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LIFE CYCLE ANALYSIS OF NATURAL GAS EXTRACTION AND POWER GENERATION: U.S. 2020 EMISSIONS PROFILE

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Disclaimer

Errata

Date: January 24, 2025

This update revises the reported proportions of natural gas (NG) delivered to each downstream delivery region from various upstream production techno-basins in Exhibit 2-3 and Appendix H of the report. This revision does not affect any of the results or conclusions of the study.

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LIST OF EXHIBITS

ACRONYMS AND ABBREVIATIONS

AF	Activity factor
AGR	Acid gas removal
ANGA	America's Natural Gas Alliance
ANL	Argonne National Laboratory
AP-42	Air Pollutant Emissions Factors
API	American Petroleum Institute
AR4	Fourth Assessment Report
AR5	Fifth Assessment Report
AR6	Sixth Assessment Report
bbl	Barrel
boe	Barrel of oil equivalent
Bcf	Billion cubic feet
Btu	British thermal unit
CBM	Coalbed methane
CCS	Carbon capture and storage
CH_4	Methane
CO	Carbon monoxide
CO_2	Carbon dioxide
CO_2e	Carbon dioxide equivalents
conv	Conventional
DI	DrillingInfo
DOE	Department of Energy
EF	Emission factor
EGDB	Energy Resources Program Geochemistry Laboratory Database
EIA	Energy Information Administration
EPA	Environmental Protection Agency
EUR	Estimated ultimate recovery
ft	Feet
g	Gram
gal	Gallon
GHG	Greenhouse gas
GHGI	Inventory of U.S. Greenhouse Gas Emissions and Sinks
GHGRP	Greenhouse Gas Reporting Program
GoM	Gulf of Mexico
GOR	Gas-to-oil ratio
GWP	Global warming potential
H_2S	Hydrogen sulfide
HF	Hydraulically fractured
HHV	Higher heating value
HP	Horsepower
HPh	Horsepower-hour
hr	Hour
ID	Identification
IPCC	Intergovernmental Panel on Climate Change
kg	Kilogram
km	Kilometer
kWh	Kilowatt hour
L	Liter
LA	Louisiana
lb	Pound
LCA	Life cycle analysis
LDC	Local distribution company
M&R	Metering and regulating
m	Meter
m^2	Square meter
Mcf	Thousand cubic feet
MJ	Mega joule
MMBtu	Million British thermal unit
MMcf	Million cubic feet
MMscf	Million standard cubic feet
mol%	Mole percent
MWh	Megawatt hour
N/A	Not applicable/available
N_2	Nitrogen
N_2O	Nitrous oxide
NETL	National Energy Technology Laboratory
NG	Natural gas
NGCC	Natural gas combined cycle
NGL	Natural gas liquid
NO_X	Oxides of nitrogen
p2.5	2.5 percentile
p97.5	97.5 percentile
PA DEP	Pennsylvania Department of Environmental Protection
PRV	Pressure relief valve
psi	Per square inch of pressure
scf	Standard cubic foot
scfh	Standard cubic foot per hour
SF_6	Sulfur hexafluoride

SO_2	Sulfur dioxide
Tcf	Trillion cubic feet
T-D	Transmission-distribution
T&D	Transmission and distribution
T&S	Transport and storage
TDS	Total dissolved solids
TNME	Throughput normalized methane emission rate
TOC	Total organic carbon
tonne	Metric ton
TX	Texas
U.S.	United States
USDA	United States Department of Agriculture
USGS	United States Geological Survey
VOC	Volatile organic compound
yr	Year

FOREWORD

This report analyzes the U.S. natural gas (NG) supply chain and studies the impact associated with an average unit of NG traversing from the upstream production basins to the downstream delivery regions. This work aims to be a stepping stone towards greater inclusion of measurement-informed data into the life cycle modeling framework. In recent years, the U.S. Department of Energy (DOE) has sponsored multiple field measurement studies aimed at improving the accuracy of emissions estimates from various sources including gathering and boosting stations, transmission stations, and marginal wells, which have been incorporated into this work. These measurement studies are helping life cycle analysis (LCA) models transition from traditional engineering-based calculations towards an approach that utilizes real time NG flow and emissions measurement data, and these improvements will continue to occur as DOE and other institutions sponsor more comprehensive field-level emissions measurement campaigns. It is worth noting that this work is a research product subject to modeling assumptions and uncertainties and is not meant to serve as an authoritative assessment of NG life cycle inventory.

The Environmental Protection Agency's (EPA) Greenhouse Gas Reporting Program (GHGRP) serves as the foundational dataset for this LCA study due to the availability of detailed facility-level emissions data across all stages of the NG supply chain. However, GHGRP data have certain limitations (such as reporting gaps related to methane emissions from "other large release events" and a facility-level reporting threshold of 25,000 metric tons of carbon dioxide [CO_2] equivalent or more per year) that are carried over to this work. This report works to address known limitations with additional emissions measurement data, engineering calculations, and extrapolation of existing data to fill gaps in reported data. In addition, EPA has also finalized revisions to the GHGRP that will address some of these limitations through improved approaches to reporting large release events and abnormal methane leaks, as well as but not limited to revisions to existing emission calculation methodologies to include the use of new measurement technologies [1]. This report recognizes the uncertainties associated with the underlying data, and the modeling framework, assumptions, methods, and references have been documented to ensure model transparency. The objective of this analysis is to calculate the U.S. average emissions from NG produced and delivered in the year 2020. The confidence intervals provided in this work represent the confidence around the average value, not the probability that a randomly selected unit of NG has a given greenhouse gas (GHG) emission profile. As such, the uncertainty estimates provided are just as important as the average values and should be considered when third parties use these estimates. Any users of these estimates should ensure that the characterization of uncertainty fits their goals and that the uncertainty is incorporated into their analyses.

As the state of science that informs our understanding of emissions across the NG supply chain continues to evolve, the NETL NG model will also continue to include new data from empirical measurement efforts, changes to EPA's GHGRP, and other resources to improve the understanding of both GHG emissions to the atmosphere as well as other releases to air, water, and land. Understanding the broader range of environmental releases is necessary to help inform effective mitigation and business strategies towards a sustainable future.

EXECUTIVE SUMMARY

Natural gas (NG) is considered a cleaner burning and more flexible alternative to other fossil fuels today. It is used in residential, commercial, industrial, and transportation applications in addition to having an expanding role in power production. This analysis expands upon previous life cycle analyses (LCAs) of NG systems performed by the Department of Energy's (DOE) National Energy Technology Laboratory (NETL) [2, 3, 4]. While this report discusses greenhouse gas (GHG) emissions in detail, it recognizes the importance of other impact categories and provides a complete inventory of emissions to air and water, water consumption, and land use change, enabling the assessment of other key impacts by researchers. These environmental burdens are detailed for all supply chain steps from NG production through NG distribution.

For the "production through distribution" life cycle boundary, the GHG emissions intensity from the United States (U.S.) NG supply chain for the year 2020 is 8.8 g carbon dioxide equivalents (CO_2e)/MJ (with a 95 percent mean confidence interval of 5.7–12.7 g CO_2e/MJ, using the Intergovernmental Panel on Climate Change [IPCC] Sixth Assessment Report [AR6] 100-yr global warming potential [GWP] values, higher heating value [HHV] basis), whereas, for the "production through transmission network" life cycle boundary, the GHG emissions from the U.S. NG supply chain are 7.8 g CO_2e/MJ (with a 95 percent mean confidence interval of 4.9–11.5 g CO_2e/MJ, IPCC AR6 100-yr GWP, HHV basis). The top contributors to carbon dioxide (CO_2) and methane (CH_4) emissions are combustion exhaust and venting from compressor systems. Compressor systems are prevalent in most supply chain stages, so compressors are significant contributors to overall life cycle emissions.

Emission rates are highly variable across the entire supply chain. The national average CH_4 emission rate (kg CH_4/kg NG delivered) for the "production through distribution" life cycle boundary is 0.74 percent, with a 95 percent mean confidence interval ranging 0.51–1.02 percent, whereas for the "production through transmission network" life cycle boundary, the national average CH_4 emission rate is 0.56 percent, with a 95 percent mean confidence interval ranging 0.37–0.80 percent. **Exhibit ES-1** and **Exhibit ES-2** depict the "production through distribution"-stage life cycle CO_2e (IPCC AR6, 100-yr GWP) and CH_4 emissions from the 2020 U.S. average NG supply chain, respectively.

Exhibit ES-1. Life cycle GHG emissions from the 2020 U.S. average NG supply chain, "production through distribution" life cycle boundary

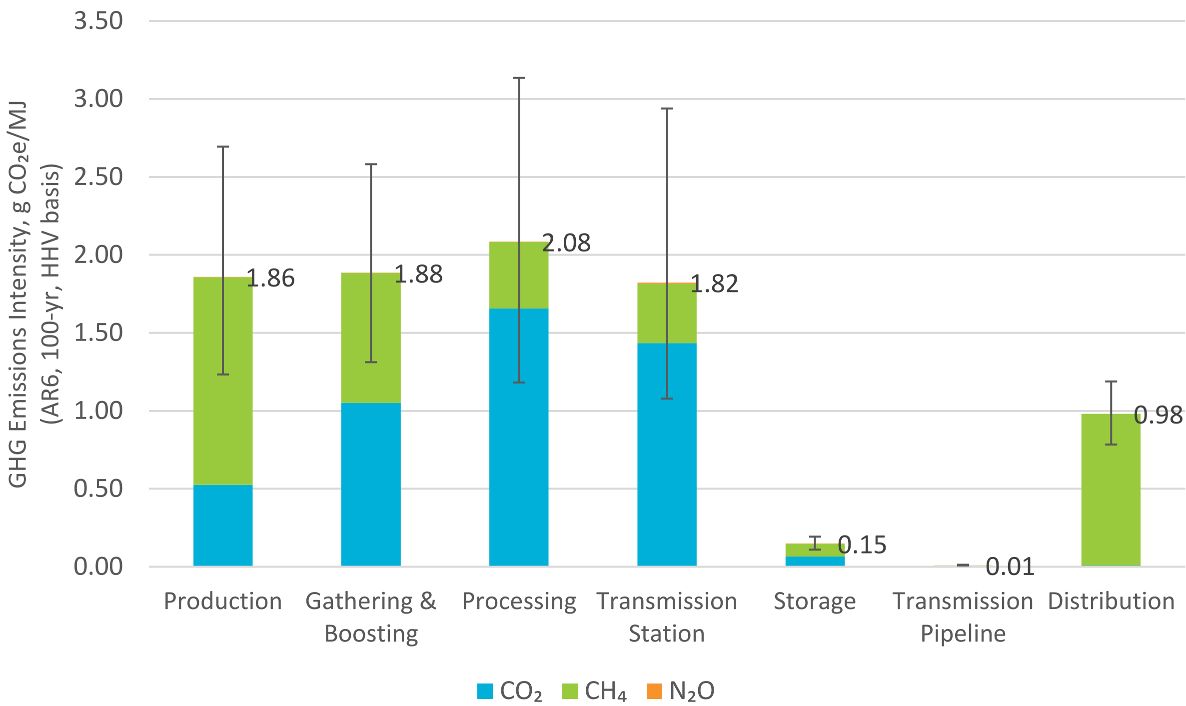
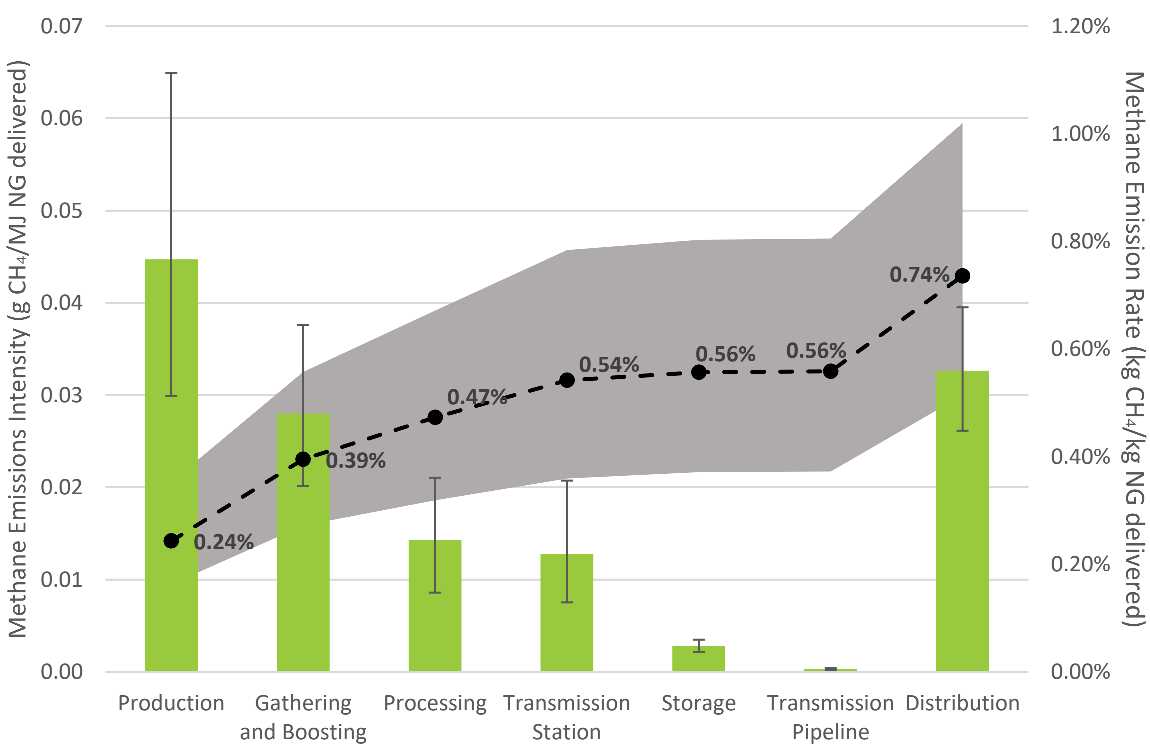


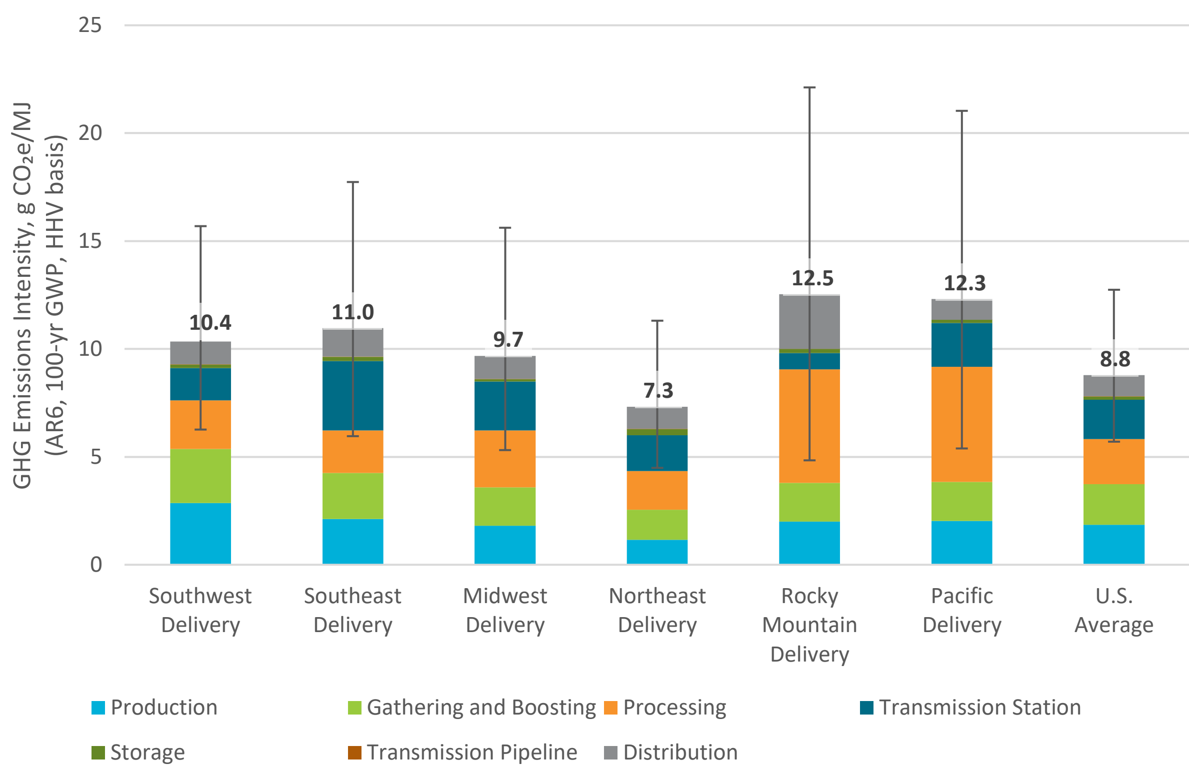
Exhibit ES-2. Life cycle CH_4 emissions from the 2020 U.S. average NG supply chain, "production through distribution" life cycle boundary



An NG consumption-weighted national average profile was estimated using the percent of gas estimated to flow through the transmission network and through the distribution network to consumers and using the "production through distribution" and "production through transmission network" life cycle boundary results. The NG consumption weighted national average GHG emissions intensity is 8.3 g CO_2e/MJ (with a mean confidence interval of 5.3–12.2 g CO_2e/MJ, AR6 100-yr GWP, HHV basis), and the CH_4 emissions rate is 0.65 percent, with a 95 percent mean confidence interval ranging 0.45–0.92 percent.

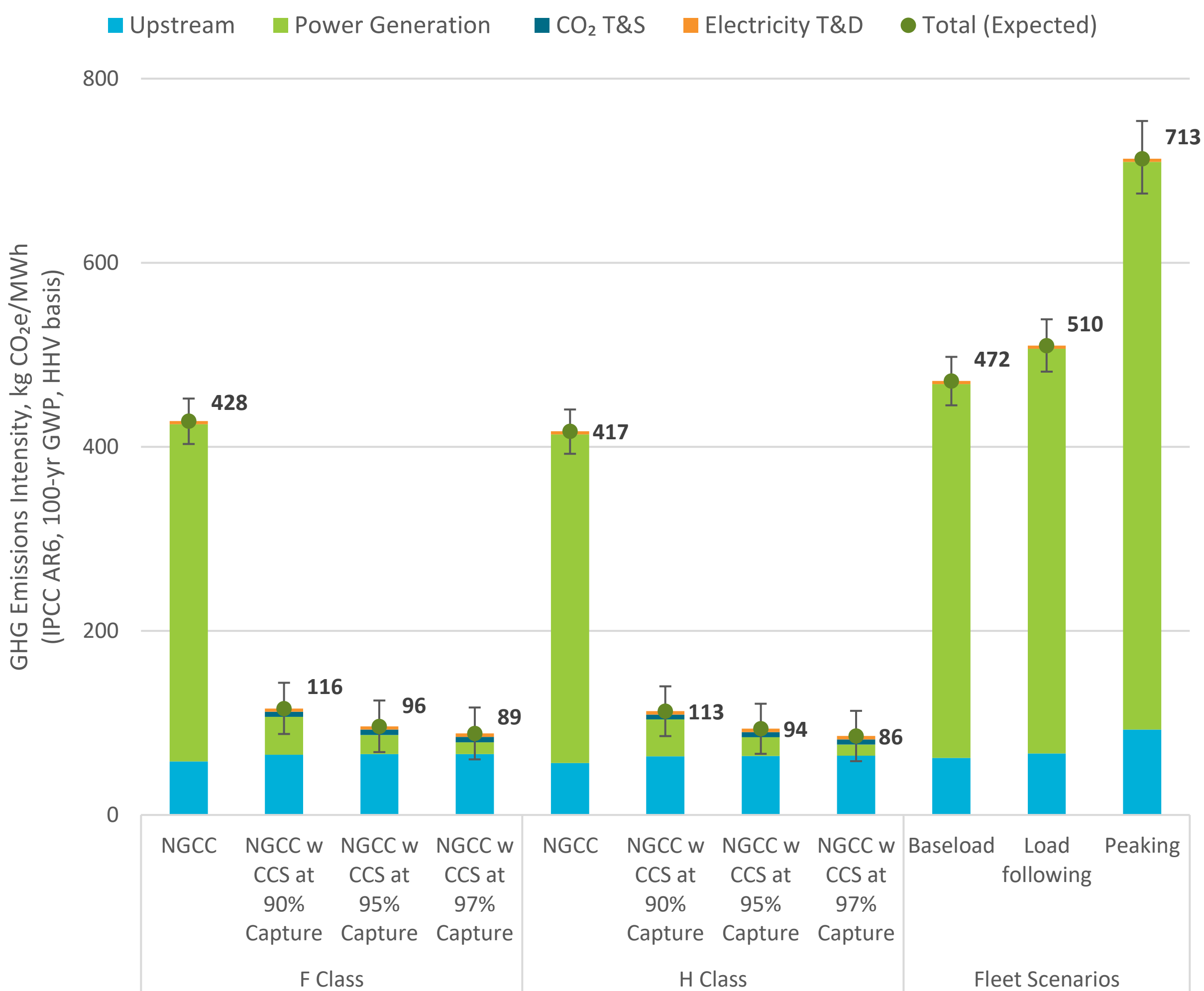
The regionalization of transmission- and distribution-stage data in this work helps facilitate understanding of the variation in GHG intensity of NG delivered to different downstream regions, as shown in **Exhibit ES-3**. The Rocky Mountain region has the highest expected "production through distribution"-stage GHG emissions intensity (12.5 g CO_2e/MJ, AR6 100-yr GWP, HHV basis), and the Northeast has the lowest (7.3 g CO_2e/MJ, AR6 100-yr GWP, HHV basis). All six regional scenarios depict wide variability in emissions intensity, with significant overlap of the mean confidence intervals.

Exhibit ES-3. GHG emissions intensity for six regional delivery scenarios from all production basins, "production through distribution" life-cycle boundary, g CO_2e/MJ (IPCC AR6, 100-year GWP, HHV basis)



This analysis also includes an expanded system boundary for domestic U.S. NG that compares the life cycle GHG emissions from advanced (both F-Class and H-Class) and fleet NG-fired power plants. The results of the expanded system are expressed in terms of electricity delivered to consumers and include all life cycle stages from NG production through electricity transmission and distribution. In terms of 100-year GWP, upstream NG[1] accounts for 13–14 percent of life cycle GHG emissions for power plants *without* carbon capture systems. For advanced NG power plants that capture CO_2 and transport it by pipeline to saline aquifer storage sites, upstream NG accounts for 57, 69, and 75 percent of life cycle GHG emissions for F-Class and 56, 68, and 75 percent of life cycle GHG emissions for H-Class at 90, 95, and 97 percent carbon capture cases, respectively, when using 100-year GWPs. **Exhibit ES-4** provides the 2020 domestic U.S. average life cycle GHG emissions through power transmission and distribution.

Exhibit ES-4. Life cycle GHG emissions through end use, IPCC AR6 100-year GWP



T&S = transport and storage; T&D = transmission and distribution

As shown in **Exhibit ES-4**, on a 100-year GWP timeframe, the expected life cycle GHG emissions from the natural gas combined cycle (NGCC) with carbon capture and storage (CCS) scenario are 73–79 percent lower than the NGCC without CCS scenario for both F- and H-Class, depending

[1] Refers to all stages upstream of the power plant gate, including production, gathering and boosting, processing, transmission station, underground storage, and transmission pipeline ("production through transmission network" life cycle boundary)

on the CO_2 capture rate employed. Comparison of NGCC plants with and without CCS illustrates a trade-off caused by environmental controls. CCS-equipped plants require energy to capture and compress CO_2. This energy demand reduces the overall efficiency of the power plant. Compared to the other power plant scenarios, NGCC with CCS has low CO_2 emissions at the power plant but higher upstream emissions than NGCC *without* CCS because it requires more NG to generate and deliver the same amount of electricity.

This work also compared these revised 2020 NG supply chain GHG intensity results with earlier work by NETL (representative of 2017 year operations) as well as the U.S. Environmental Protection Agency's (EPA) Inventory of U.S. Greenhouse Gas Emissions and Sinks (GHGI) for the year 2020 [5, 6]. The emissions intensity of the 2020 U.S. average profile has decreased by 32 percent on a Fifth Assessment Report (AR5) 100-year GWP basis relative to 2017 year operations. This reduction in GHG emissions intensity is due to a combination of multiple factors, including (1) changes in production shares resulting in a greater proportion of gas coming from Appalachian Shale; (2) operational changes in the NG supply chain over the three-year period; (3) modeling changes incorporated into this study, including the energy allocation of burdens between NG and NG supply chain co-products, regionalization of processing-stage data, and regionalization of transmission- and distribution-stage data; and (4) modeling updates to reflect 2020 operating year conditions and the latest state of the science, such as revision of liquids unloading throughput normalized methane emission rate values, updated emissions factors for gathering- and boosting-stage equipment, and updated emission factors for commercial and industrial meters in the distribution stage. Based on the degree of changes to the NETL modeling approach, GHGRP reporting changes, and updates to reflect the current state of the science, it is difficult to assess whether the actual emissions intensity has increased or decreased since the last study. The reported results improve accuracy based on supplementing industry-reported data with field-level measured data. New scientific understandings from measurement campaigns and improved reporting requirements will continue to improve the accuracy and understanding of U.S. NG supply emissions by techno-basin.

The methane emissions intensity for the gathering-and-boosting and transmission network stages is estimated to be 29 percent and 61 percent lower, respectively, in this work as compared to methane intensities calculated using EPA's GHGI, whereas the distribution-stage methane emissions intensity is estimated to be 133 percent higher. This is primarily due to the incorporation of various measurement-informed studies in this work and differing modeling approaches between the two data sources.

1 Introduction

Natural gas (NG) is a cleaner-burning and more flexible alternative to other fossil fuels today. It is used in residential, commercial, industrial, and transportation applications in addition to its expanding role in power production. However, the primary component of NG is methane (CH_4), a greenhouse gas (GHG) that, depending on timeframe, is 29.8–82.5 times as potent as carbon dioxide (CO_2) [7].

This analysis expands upon previous life cycle analyses (LCAs) of NG systems performed by the Department of Energy's (DOE) National Energy Technology Laboratory (NETL) [2, 3, 4]. It describes in detail the GHG emissions due to production, gathering and boosting, processing, transmission, storage, and distribution of domestic United States (U.S.) NG to consumers. Life cycle emission inventories are created for the 2020 average NG production mix. It is worth noting that this work is a research product subject to modeling assumptions and uncertainties and is not meant to serve as an authoritative assessment of natural gas life cycle inventory.

This analysis also includes an expanded system boundary for domestic U.S. NG that compares the life cycle GHG emissions from advanced and fleet NG-fired power plants. The results for this expanded system are expressed in terms of a unit of electricity delivered to the end user and include all life cycle stages from fuel extraction through electricity transmission and distribution. This comparison provides perspective on the scale of fuel extraction and delivery emissions relative to subsequent emissions from power generation and electricity transmission.

There are many opportunities to decrease the GHG emissions from NG extraction, delivery, and power production, including the reduction of fugitive CH_4 emissions at wells and the implementation of advanced combustion technologies and CCS. GHGs are not the only metric that should be considered when comparing energy options, so this analysis also includes a full inventory of air emissions, water use and quality, and land use.

2 Scope and Boundaries

LCA is a systematic approach that calculates the environmental burdens of a product or system. NETL's NG life cycle model is a compilation of unit processes in which parameters are scaled to reflect a functional unit of NG that accounts for uncertainty across multiple scenarios. An LCA requires a functional unit, boundaries, scenarios, and metrics.

2.1 Functional Unit

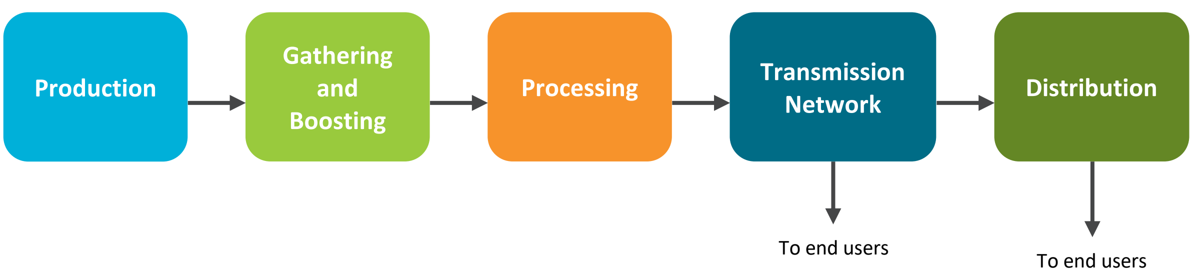
A functional unit is necessary to provide a common basis for scaling life cycle stages and, in some instances, to compare scenarios. The functional unit for this analysis is 1 megajoule[2] (MJ) of NG delivered to the consumer through the distribution network, where the consumer is a combination of commercial, residential, industrial, and power sector end users.

This analysis also uses alternative functional units of 1 MJ of NG delivered directly to end users (typically industrial and power sectors) via transmission pipeline (production through transmission network) and 1 MWh of electricity consumed by an end user to provide perspective on the environmental burdens associated with one of the largest consumers of NG, electric power generation.

2.2 Boundaries

This is a cradle-to-gate analysis that begins with all construction and operation activities necessary to extract NG from the earth, including intermediate gathering, processing, and transport steps and ending with the delivery of NG to large- and small-scale users. These stages are illustrated in **Exhibit 2-1**.

Exhibit 2-1. Supply chain stages that compose the overall study boundary



Note: The transmission network stage includes the transmission station, storage, and transmission pipeline stages

There are five stages in the supply chain:

- **Production:** An NG production site has a well pad that holds permanent equipment and provides room for development and maintenance activities. The construction of NG wells requires a well casing that provides strength to the well bore and prevents contamination of the geological formations that surround the gas reservoir. For offshore

[2] The results in this work are on a higher heating value (HHV) basis, using an HHV of 54.3 MJ/kg (or 1037 BTU/scf), and an NG density of 0.044 lb/scf.

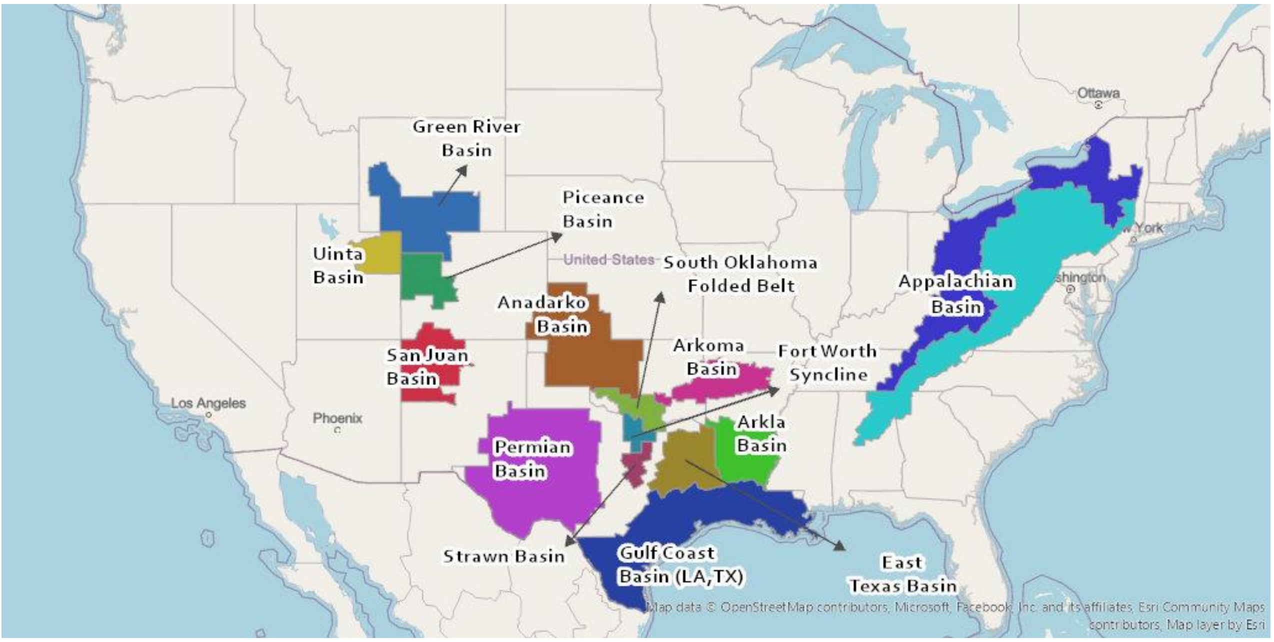
extraction, a platform is also required. Well completions are the activities following well drilling and preceding production and, in the case of unconventional wells, involve the injection and flowback of water to stimulate production. Liquids unloading is an intermittent practice employed to maintain the flow of gas from NG-producing wells, which may yield emissions of methane. Other sources of emissions include the gas vented from pneumatically controlled devices and fugitive emissions from flanges, connectors, open-ended lines, and valves. When vapor recovery units are feasible, vented gas is captured for sale or use; otherwise, vented gas is released to the atmosphere or directed to flare. Production operations also include the combustion of NG and diesel as fuel for driving compressors and other equipment.

- **Gathering and Boosting:** NG gathering and boosting networks receive NG from multiple wells and transport it to gas treatment or processing plants, or, in some cases, directly to transmission pipelines. Gathering and boosting sites include acid gas removal (AGR) sites, dehydrators, compressors, pneumatic devices, tanks, and pumps.
- **Processing:** An NG processing facility removes impurities from NG, which improves its heating value and prepares it for pipeline transmission. NG processing facilities may include AGR, dehydration, natural gas liquid (NGL) recovery, and compression. When feasible, vapor recovery units capture vented gas for sale or use; otherwise, vented gas is released to the atmosphere or directed to flares. The size and complexity of processing plants are variable; in some cases, processing plants are located near production sites, while in other cases, a central processing facility receives NG from gathering systems.
- **Transmission Stations/Storage/Transmission Pipelines (Transmission Network):** An NG transmission system is a network of large pipelines that transports NG from processing facilities to the city gate (the point at which NG is consumed by end users directly or transferred to local distribution companies). A typical NG transmission pipeline is between 24 and 36 inches in diameter and is constructed of carbon steel [8]. Transmission pipelines operate at high pressures (around 200–1,500 psi) [9]. Transmission compression stations are located along NG transmission pipelines and use compressors to boost the pressure of NG. These stations consist of centrifugal and reciprocating compressors; most pipeline compressors are powered by NG, but some are powered by electricity. The transmission network also includes subsurface storage facilities, for example, stations that may inject and withdraw gas from subsurface salt domes or other geological formations. Storage facilities may feature pneumatic devices and compressors and may yield fugitive emissions from flanges, connectors, open-ended lines, and valves for both the storage station and wellhead.
- **Distribution:** NG distribution networks transport NG from the city gate stations to commercial, residential, and some industrial consumers. Distribution pipelines operate at pressure ranges from 0.25 to 200 psi [10]. This analysis uses the distribution portion of the supply chain only for the upstream functional unit; distribution is not included for the functional unit of electricity as NG power plants primarily receive NG directly from transmission pipelines.

2.3 Scenarios

This analysis explores 29 distinct scenarios. The scenarios include 14 onshore production *basins* (shown in **Exhibit 2-2**) with their respective *extraction technologies*, for a total of 27 onshore scenarios, as well as two offshore production scenarios for the Gulf of Mexico (GoM) and offshore Alaska. The results include a national average based on a production-weighted aggregation of the onshore and offshore scenarios.

Exhibit 2-2. Basins that account for the majority of U.S. NG production



Five types of extraction technologies are considered:

- *Conventional (conv)* NG is extracted via vertical wells in high permeability formations that do not require stimulation technologies (for example, hydraulic fracturing) for primary production.
- *Coalbed methane (CBM)* is extracted from wells drilled into coal seams that require the removal of naturally occurring water before they are productive.
- *Shale gas* is extracted from low permeability formations that require hydraulic fracturing and horizontal drilling.
- *Tight gas* is extracted from non-shale, low-permeability formations that require hydraulic fracturing and directional drilling.
- *Associated gas* is found with petroleum (either dissolved in oil or in a gas cap in a petroleum formation) and is produced by oil wells.[3]

[3] The associated gas scenario is not modeled separately as part of this update. Instead, associated gas production shares are embedded into the various onshore techno-basin scenarios modeled in this work. Please see **Appendix G** for additional details.

Exhibit 2-3 shows the 2020 production shares[4] for the 27 onshore and 2 offshore scenarios. These production shares are based on filtered Environmental Protection Agency (EPA) Greenhouse Gas Reporting Program (GHGRP) production data for 2020, complemented by Energy Information Administration (EIA) production statistics for offshore NG in 2020 [11, 12]. The complete methodology for estimation of production shares using GHGRP and EIA data is discussed in **Appendix G**. The 14 onshore production regions in **Exhibit 2-3** do not represent *all* onshore production regions; they represent the most productive onshore regions, which account for 75 percent of total U.S. NG marketed production in 2020. **Exhibit 2-3** extrapolates the production shares of these 14 onshore regions to represent all onshore production (around 97.0 percent of total U.S. production). The balance of U.S. NG production is represented by offshore NG (3.0 percent).

Multiple studies have highlighted the importance of accounting for methane emissions from marginal or low-production wells (wells with an average production of less than 15 barrels of oil equivalent [boe]/day) to develop an accurate emissions inventory for the petroleum and NG supply chain [13, 14]. This report relies on field-level measurement work to account for the high methane emission rates (production-normalized) from marginal gas production wells (mean methane emission rate of 1.2 percent) [13]. In support of an ancillary bounding analysis to represent marginal well methane emissions in the 2020 U.S. average life cycle emissions profile, several assumptions were made. The lower bound for share of NG production from marginal well sites was selected as 5.5 percent [14], and the upper bound was selected as 8 percent [13]. Results of this bounding analysis are shown in the Results section (see **Section 6.4**).

Exhibit 2-3. NG production shares by well type and geography

Geography	Well Type					
	Conv	Shale	Tight	CBM	Offshore	Total
Onshore Production						
Anadarko	1.83%	2.64%	1.90%	-	-	6.36%
Appalachian[1, 2]	-	38.68%	-	-	-	38.68%
Arkla	3.30%	5.78%	0.90%	-	-	9.98%
Arkoma[2]	0.55%	1.76%	-	-	-	2.31%
East Texas	0.81%	0.70%	3.78%	-	-	5.30%
Fort Worth[2]	-	0.89%	-	-	-	0.89%
Green River	0.06%	-	2.64%	-	-	2.70%
Gulf Coast	2.72%	3.52%	0.77%	-	-	6.98%
Permian[2]	9.76%	7.09%	-	-	-	16.85%
Piceance[2]	-	-	1.87%	-	-	1.87%
San Juan[2]	-	1.08%	-	0.93%	-	2.01%
South Oklahoma[2]	-	0.95%	-	-	-	0.95%
Strawn[2]	-	1.52%	-	-	-	1.52%

[4] In this work, production share represents the volume of NG produced for sales in each techno-basin as a share of total U.S. marketed NG production in 2020.

Geography	Well Type					
	Conv	Shale	Tight	CBM	Offshore	Total
Uinta	0.03%	-	0.59%	-	-	0.62%
Subtotal: Onshore	*19.06%*	*64.61%*	*12.45%*	*0.93%*	-	*97.05%*
Offshore Production						
Offshore GoM	-	-	-	-	2.81%	2.81%
Offshore Alaska	-	-	-	-	0.14%	0.14%
Subtotal: Offshore	-	-	-	-	*2.95%*	*2.95%*
Total						
Total[3]	**19.06%**	**64.61%**	**12.45%**	**0.93%**	**2.95%**	**100%**

[1] The Appalachian techno-basin scenario modeled in this work represents aggregated GHGRP-reported data for Appalachian basin 160 and Appalachian basin 160A (Eastern Overthrust).
[2] These basins represent aggregated shale and tight production shares classified under either the shale or tight category (depending on the basin), to limit the number of scenarios modeled in this work.
[3] Due to rounding errors, the subtotals for onshore wells and the totals for all well types do not exactly match the sums of values reported for individual well types.

2.4 Metrics

This analysis is a comprehensive LCA that accounts for emissions to air and water, water use, and land use. Air emissions comprise GHG emissions, criteria air pollutants, and other air emissions of concern. Water emissions comprise total dissolved solids (TDS), various metals and minerals, and radionuclides. Water use accounts for the withdrawal and discharge of water used for well stimulation (i.e., hydraulic fracturing) and the discharge of produced water, which is the water produced along with the NG from NG formations. Land use accounts for the area of land affected by NG infrastructure, as well as the GHG emissions caused by the removal of above-ground biomass and fluxes in soil and root carbon.

In this analysis, impact assessment is limited to the application of global warming potential (GWP) to all inventoried GHG emissions. The primary GHG emissions results are reported on a common-mass basis of carbon dioxide equivalents (CO_2e) using the GWPs of each gas from the Intergovernmental Panel on Climate Change (IPCC) Sixth Assessment Report (AR6) [7]. The default GWP used is the 100-year timeframe, but in some cases, results for the 20-year timeframe are presented as well. All GHG results in this analysis are expressed as 100-year GWPs unless specified otherwise. **Exhibit 2-4** shows the GWPs used for the GHGs that were inventoried. It is worth noting that all GHG emissions results are also provided on an alternate GWP basis (IPCC Fourth Assessment Report [AR4] and Fifth Assessment Report [AR5], 100- and 20-year) in **Appendix E** (available in the release package published along with this report).

Exhibit 2-4. IPCC GWP factors from AR4, AR5, and AR6 (kg CO_2e/kg of GHG emitted)

GHG	AR4 (20-year)	AR4 (100-year)	AR5 (20-year)	AR5 (100-year)	AR6 (20-year)	AR6 (100-year)
CO_2	1	1	1	1	1	1
CH_4	72	25	86	36	82.5	29.8
N_2O	289	298	268	298	273	273
SF_6	16,300	22,800	17,783	26,087	18,300	25,200

2.5 Timeframe

The objective of this analysis is to represent the 2020 U.S. NG supply chain from a life-cycle perspective. During the development of this analysis, 2020 was the most recent year represented by key data sources, which include the GHGRP, Enverus (formerly DrillingInfo) Desktop tool [15], and EIA. These sources provide information on equipment counts, emission events, and NG throughput for all supply chain stages.

The results of this analysis are representative of *activities* that happened in 2020. In some instances, the *emissions* from those activities do not occur within a single year. There are three types of activities in the NG supply chain that affect the long-term performance of wells or induce emissions that are released for more than one year:

- Well construction is an activity that happens within a single year but makes lifetime production of NG possible. This analysis calculates the fuel consumption for drilling, steel and concrete requirements for wellbores and casings, and direct and upstream emissions associated with fuels and construction materials used for wells producing gas in 2020. These environmental burdens are divided by the estimated ultimate recovery (EUR) of the constructed wells (as discussed in **Section 3.2**) to apportion well construction burdens to each unit of NG produced during a well's lifetime.

- Well stimulation events are episodic events that, like well construction, happen once or twice in a well's lifetime and make lifetime production of NG possible. This analysis calculates the water consumption associated with stimulation of wells that were producing gas in 2020 (as discussed in **Section 3.3**). These environmental burdens are normalized by the EUR of the producing wells, which again uniformly apportions the environmental burdens from well stimulation to each unit of NG produced during a well's lifetime.

- Land use change represents the transformation of land from its current form to an industrial application (e.g., the transformation of grassland to a well pad or the transformation of forest to a pipeline right-of-way). Additionally, when agricultural land is converted to industrial applications, *indirect* land use change accounts for new agricultural land that is established elsewhere to make up for the displaced agricultural land. Land use change disturbs the balance of carbon in above-ground biomass, roots, and soil, thus inducing a multi-year flux of CO_2 and CH_4 emissions (as discussed in **Section 3.10**). For land use change that is induced by production, this analysis estimates the lifetime land use change emissions from production sites that were operating in

2020, and then divides the emissions by the EUR of the production sites. For land use change that is induced by gathering and boosting systems, data limitations prevent the modeling of 2020 activity specifically (the year in which a given gathering and boosting system was constructed is unknown). Due to this data limitation, this analysis apportions the land area for gathering and boosting systems to the lifetime throughput of gathered NG; this method implies that there is no temporal variability for gathering and boosting land use burdens.

3 DATA

The data used in this analysis comprise all stages of the NG supply chain: production, gathering and boosting, processing, transmission, storage, and distribution. This section aims to provide an overview of the available data to establish a background for the discussion in **Section 4** regarding the use and connectivity of these data across the various NG supply chain stages in the LCA modeling framework.

3.1 NATURAL GAS COMPOSITION

The composition of NG affects the profile of air emissions upon venting and flaring of NG. NG composition data were obtained from the United States Geological Survey (USGS) Energy Resources Program Geochemistry Laboratory Database (EGDB). EGDB contains over 200,000 data samples, providing chemical analyses of produced NG, coal, water, and other samples [16]. The data represent individual well samples that USGS analyzed for chemical composition. The data vary geographically and are available for the 14 basins of this analysis. There is no time stamp on the data. Given that the composition of NG in a formation does not change over decadal time scales, historical data in EGDB are representative of NG compositions in 2020.

The EGDB data were stratified by location (county, state, country, latitude, and longitude) and then aligned to NG production basins. Each record contains a gas composition profile for a single well. These records were filtered as follows:

1. Gas species that were reported as multi-component categories were deleted from each record. (This comprised three categories: oxygen and argon, undifferentiated C5+, and undifferentiated C6+.)
2. Gas species that were reported for a minority of records were removed. (This comprised nine species: 1-butene, benzene, cis-2-butene, ethylene, hydrogen sulfide [H_2S], iso-butene, neo-pentane, n-heptane, and n-hexane.)
3. Records with a total mol% of 99–101 percent were retained. Records that fell outside of this range represented an incomplete or overstatement of emission fraction and were discarded.
4. Records with total hydrocarbon mole fractions of less than 50 percent were discarded because they are not representative of oil or NG wells; they are more likely marketable sources of CO_2 or helium.

After these filters were applied, the total records were reduced from 13,875 to 9,362 (a 33 percent reduction in record count). This reduction in records was necessary to remove ambiguous, under-reported, or non-representative data and affected each basin disproportionately. **Exhibit 3-1** shows the original and filtered record count for each basin.

Exhibit 3-1. NG records reduction due to data filtering

Basin	Record Count in Raw Data	Record Count After Filtering
Anadarko	2,958	2,203
Appalachian	380	362
Arkla	205	68
Arkoma	512	360
East Texas	267	69
Fort Worth	74	62
Green River	444	240
Gulf Coast	1,511	895
Permian	753	434
Piceance	319	181
San Juan	853	481
South Oklahoma	158	136
Strawn	17	15
Uinta	167	121

In addition to the above filtering, two criteria were used to convert ambiguous data points to zeros. Gas species with an entry of "<0.01" were changed to 0 mol%, and gas species with blank entries (i.e., no data) were changed to 0 mol%. Each filtered data record was normalized to represent an NG composition profile of exactly 100 mol%. Mole fractions were then converted to mass fractions.

The standard error of the mean was calculated for the gas compositions in each basin, allowing the computation of a 95 percent confidence interval for the mean composition of each gas species. (**Section 5.2** provides more background on the theory behind standard error of the mean.) For this analysis, understanding the uncertainty in parameter averages is appropriate because the objective is to calculate average life cycle emissions, not the probability that a single well will have a specific emission profile. For instance, the Appalachian basin includes wells in the Marcellus region that have high shares of heavy hydrocarbons that are separated as NG liquids; this analysis accounts for these wells in its profile of Appalachian NG production but aggregates them with other Appalachian wells that have dry gas. Standard error of the mean allows aggregation of these wells in a way that robustly accounts for variability within a basin.

The NG compositions for each basin are shown in **Exhibit 3-2**.

Exhibit 3-2. Produced NG compositions for 14 production basins (mass fractions)

Basin	Statistic	Air	Argon	Carbon Dioxide	Ethane	Helium	Hydrogen	iso-Butane	iso-Pentane	Methane	n-Butane	Nitrogen	n-Pentane	Oxygen	Propane
Anadarko	Mean	0.00E+00	4.75E-04	0.00E+00	9.71E-02	6.99E-04	3.73E-05	1.16E-02	7.92E-03	6.69E-01	2.36E-02	1.18E-01	7.02E-03	1.61E-03	6.28E-02
	p2.5	0.00E+00	3.80E-04	0.00E+00	9.49E-02	6.60E-04	3.00E-05	1.13E-02	7.61E-03	6.63E-01	2.30E-02	1.13E-01	6.80E-03	1.40E-03	6.14E-02
	p97.5	0.00E+00	5.71E-04	0.00E+00	9.93E-02	7.38E-04	4.47E-05	1.20E-02	8.22E-03	6.75E-01	2.42E-02	1.23E-01	7.25E-03	1.82E-03	6.42E-02
Appalachian	Mean	7.39E-03	2.25E-04	9.22E-04	8.04E-02	3.03E-05	6.80E-05	5.23E-03	2.88E-03	8.36E-01	9.57E-03	3.02E-02	3.27E-03	1.18E-03	2.99E-02
	p2.5	2.57E-03	0.00E+00	4.23E-04	7.35E-02	2.67E-05	5.32E-05	4.41E-03	2.40E-03	8.23E-01	8.25E-03	2.47E-02	2.73E-03	7.93E-04	2.61E-02
	p97.5	1.22E-02	4.58E-04	1.42E-03	8.73E-02	3.39E-05	8.27E-05	6.04E-03	3.36E-03	8.49E-01	1.09E-02	3.57E-02	3.81E-03	1.57E-03	3.36E-02
Arkla	Mean	0.00E+00	3.38E-05	7.41E-03	4.72E-02	8.38E-05	1.39E-05	8.06E-03	4.58E-03	8.49E-01	8.51E-03	5.41E-02	3.33E-03	1.64E-03	1.63E-02
	p2.5	0.00E+00	0.00E+00	3.15E-03	2.69E-02	6.53E-05	4.79E-06	3.02E-03	2.35E-03	8.14E-01	4.42E-03	4.40E-02	1.87E-03	6.38E-04	8.58E-03
	p97.5	0.00E+00	1.01E-04	1.17E-02	6.78E-02	1.02E-04	2.32E-05	1.31E-02	6.83E-03	8.84E-01	1.26E-02	6.43E-02	4.81E-03	2.64E-03	2.40E-02
Arkoma	Mean	9.15E-04	2.48E-04	6.37E-04	3.13E-02	2.37E-04	7.85E-05	6.48E-04	6.55E-04	9.20E-01	1.38E-03	3.35E-02	5.80E-04	3.03E-03	6.40E-03
	p2.5	0.00E+00	1.69E-04	1.20E-04	2.71E-02	2.21E-04	6.36E-05	4.10E-04	4.15E-04	9.12E-01	8.86E-04	2.75E-02	3.40E-04	2.23E-03	5.09E-03
	p97.5	1.90E-03	3.28E-04	1.15E-03	3.55E-02	2.52E-04	9.35E-05	8.86E-04	8.95E-04	9.29E-01	1.87E-03	3.95E-02	8.20E-04	3.83E-03	7.70E-03
East Texas	Mean	0.00E+00	6.67E-05	1.04E-02	9.00E-02	1.72E-04	8.73E-05	5.22E-03	1.75E-03	7.81E-01	4.43E-02	4.25E-02	6.10E-03	2.10E-03	1.58E-02
	p2.5	0.00E+00	0.00E+00	5.61E-03	6.51E-02	2.50E-05	0.00E+00	3.68E-03	1.02E-03	7.36E-01	1.47E-03	3.22E-02	2.26E-03	1.20E-03	1.04E-02
	p97.5	0.00E+00	1.58E-04	1.52E-02	1.15E-01	3.18E-04	1.95E-04	6.75E-03	2.47E-03	8.27E-01	8.71E-02	5.28E-02	9.93E-03	3.01E-03	2.12E-02
Fort Worth	Mean	0.00E+00	3.06E-05	0.00E+00	1.59E-01	3.18E-04	3.77E-05	1.71E-02	1.06E-02	6.15E-01	3.16E-02	6.13E-02	9.34E-03	1.58E-03	9.43E-02
	p2.5	0.00E+00	0.00E+00	0.00E+00	1.27E-01	2.31E-04	1.31E-05	1.48E-02	8.35E-03	5.86E-01	2.70E-02	4.50E-02	7.79E-03	9.13E-04	8.20E-02
	p97.5	0.00E+00	9.07E-05	0.00E+00	1.92E-01	4.06E-04	6.23E-05	1.94E-02	1.28E-02	6.44E-01	3.62E-02	7.76E-02	1.09E-02	2.24E-03	1.07E-01
Green River	Mean	4.99E-02	7.43E-05	5.51E-03	7.96E-02	5.16E-05	2.55E-05	1.15E-02	7.09E-03	7.66E-01	1.33E-02	2.29E-02	4.27E-03	1.76E-03	3.84E-02
	p2.5	3.74E-02	2.35E-05	4.01E-03	6.84E-02	3.04E-05	1.60E-05	9.46E-03	5.76E-03	7.46E-01	1.08E-02	1.59E-02	3.36E-03	8.76E-04	3.29E-02
	p97.5	6.24E-02	1.25E-04	7.01E-03	9.08E-02	7.29E-05	3.49E-05	1.35E-02	8.42E-03	7.85E-01	1.58E-02	2.99E-02	5.18E-03	2.64E-03	4.39E-02
Gulf Coast	Mean	4.03E-03	4.29E-05	5.68E-03	7.22E-02	2.58E-06	2.35E-05	1.15E-02	5.87E-03	8.35E-01	1.17E-02	1.40E-02	4.68E-03	1.61E-03	3.32E-02
	p2.5	2.49E-03	2.12E-05	4.02E-03	6.78E-02	2.12E-06	1.65E-05	1.08E-02	5.41E-03	8.28E-01	1.07E-02	1.26E-02	4.30E-03	1.32E-03	3.09E-02
	p97.5	5.57E-03	6.45E-05	7.33E-03	7.66E-02	3.05E-06	3.05E-05	1.23E-02	6.33E-03	8.43E-01	1.27E-02	1.55E-02	5.05E-03	1.90E-03	3.55E-02
Permian	Mean	0.00E+00	1.27E-04	2.24E-02	1.17E-01	1.69E-04	2.78E-05	1.02E-02	6.75E-03	6.88E-01	1.97E-02	7.23E-02	5.88E-03	2.30E-03	5.52E-02
	p2.5	0.00E+00	7.38E-05	1.23E-02	1.07E-01	1.45E-04	1.83E-05	9.32E-03	6.06E-03	6.71E-01	1.79E-02	6.24E-02	5.28E-03	1.66E-03	5.06E-02
	p97.5	0.00E+00	1.80E-04	3.24E-02	1.27E-01	1.92E-04	3.73E-05	1.11E-02	7.45E-03	7.05E-01	2.14E-02	8.23E-02	6.48E-03	2.95E-03	5.97E-02

Basin	Statistic	Air	Argon	Carbon Dioxide	Ethane	Helium	Hydrogen	iso-Butane	iso-Pentane	Methane	n-Butane	Nitrogen	n-Pentane	Oxygen	Propane
Piceance	Mean	7.05E-02	1.49E-04	3.82E-02	1.19E-01	1.40E-04	3.29E-05	1.08E-02	6.88E-03	6.61E-01	1.22E-02	3.54E-02	3.87E-03	1.01E-03	4.05E-02
	p2.5	5.43E-02	3.19E-06	2.71E-02	9.43E-02	9.74E-05	2.14E-06	8.92E-03	4.75E-03	6.29E-01	1.00E-02	2.53E-02	3.09E-03	4.77E-04	3.11E-02
	p97.5	8.66E-02	2.95E-04	4.93E-02	1.44E-01	1.83E-04	6.36E-05	1.27E-02	9.00E-03	6.93E-01	1.43E-02	4.55E-02	4.65E-03	1.55E-03	4.99E-02
San Juan	Mean	8.77E-02	6.70E-05	3.11E-02	7.73E-02	6.95E-05	3.65E-05	9.96E-03	5.22E-03	7.19E-01	1.24E-02	1.17E-02	3.70E-03	9.81E-04	4.11E-02
	p2.5	7.41E-02	2.38E-05	2.60E-02	7.08E-02	2.63E-05	4.46E-06	8.97E-03	4.63E-03	7.07E-01	1.12E-02	8.24E-03	3.26E-03	6.12E-04	3.75E-02
	p97.5	1.01E-01	1.10E-04	3.62E-02	8.39E-02	1.13E-04	6.86E-05	1.10E-02	5.80E-03	7.30E-01	1.35E-02	1.51E-02	4.14E-03	1.35E-03	4.48E-02
South Oklahoma	Mean	0.00E+00	8.83E-05	0.00E+00	1.41E-01	1.66E-04	2.40E-05	8.33E-03	5.51E-03	7.10E-01	2.07E-02	5.39E-02	6.87E-03	2.67E-03	5.11E-02
	p2.5	0.00E+00	8.85E-06	0.00E+00	1.18E-01	1.23E-04	1.50E-05	6.99E-03	4.34E-03	6.87E-01	1.74E-02	4.18E-02	5.68E-03	1.83E-03	4.37E-02
	p97.5	0.00E+00	1.68E-04	0.00E+00	1.63E-01	2.08E-04	3.30E-05	9.67E-03	6.67E-03	7.34E-01	2.40E-02	6.61E-02	8.06E-03	3.52E-03	5.85E-02
Strawn	Mean	0.00E+00	2.97E-04	0.00E+00	1.28E-01	3.98E-04	4.66E-05	9.40E-03	6.61E-03	7.08E-01	1.78E-02	7.17E-02	4.08E-03	2.07E-03	5.16E-02
	p2.5	0.00E+00	0.00E+00	0.00E+00	9.08E-02	2.89E-04	7.22E-08	4.40E-03	2.58E-03	6.56E-01	1.00E-02	5.53E-02	1.56E-03	1.75E-04	2.98E-02
	p97.5	0.00E+00	6.95E-04	0.00E+00	1.66E-01	5.08E-04	9.30E-05	1.44E-02	1.06E-02	7.59E-01	2.56E-02	8.81E-02	6.61E-03	3.97E-03	7.34E-02
Uinta	Mean	4.31E-02	1.03E-04	1.69E-02	5.76E-02	1.33E-05	2.11E-05	8.19E-03	5.40E-03	8.08E-01	9.56E-03	1.52E-02	4.09E-03	1.83E-03	3.04E-02
	p2.5	2.98E-02	9.08E-06	1.09E-02	4.82E-02	9.15E-06	1.10E-05	6.55E-03	4.01E-03	7.86E-01	7.34E-03	6.70E-03	2.87E-03	2.28E-04	2.41E-02
	p97.5	5.65E-02	1.97E-04	2.29E-02	6.69E-02	1.74E-05	3.12E-05	9.82E-03	6.80E-03	8.30E-01	1.18E-02	2.36E-02	5.31E-03	3.43E-03	3.67E-02

p2.5 = 2.5 percentile; p97.5 = 97.5 percentile

3.2 Estimated Ultimate Recovery

Processes such as well construction, well stimulation, and land use change, which are accompanied by episodic venting or water flows, occur only once or twice during the life of a well. To account for the environmental impacts of these operations, this analysis has normalized the environmental burdens of these events over a well's EUR, which estimates the total oil or gas production expected over a well's lifetime. Enverus provides two distinct estimates of EUR by well [15, 17]. The *best effort forecast* calculates EUR by assessing individual trends for different periods within the production history. Trends are ranked based on how recently they occurred and the number of data points to which they conform. The highest ranked trend is used for the forecast. The *full forecast* comprises the entire production history to determine a fit. This method requires the specification of an initial production decline rate (D_i) and an exponent (the *b factor*) that describes whether the production curve exhibits hyperbolic or exponential decline. As part of this work, comparing EUR estimated using the *best effort forecast* to the *full forecast* demonstrated no bias, indicating that averages estimated from either method should be sufficiently similar in order to justify either EUR estimation method for modeling. The NG LCA model used EUR estimated by the *best effort forecast*.

The EUR data were filtered to exclude wells producing a relatively high share of oil. This analysis excludes wells with a gas-to-oil ratio (GOR) less than 100 Mcf/bbl, which is consistent with EPA methods [18]. GOR was calculated based on the most recent 12 months of production.

Filtered EUR estimates were then grouped by scenario (basin and well type) for all wells active in 2020 using the bootstrapping technique described in **Section 5.2**. **Exhibit 3-3** shows the EUR parameters used in NETL's NG life cycle model (the "NG model"), which include the weighted means, the p2.5, and the p97.5 confidence intervals for the mean value.

Exhibit 3-3. NG EUR by basin and well type

Basin	Well Type	Mean EUR (Mcf)	p2.5 EUR (Mcf)	p97.5 EUR (Mcf)
Anadarko	Conv	2.86E+06	2.61E+06	3.15E+06
	Shale	1.28E+07	1.13E+07	1.48E+07
	Tight	7.28E+06	6.28E+06	8.32E+06
Appalachian	Shale	1.81E+07	1.77E+07	1.84E+07
Arkla	Shale	2.01E+07	1.91E+07	2.12E+07
	Conv	1.94E+07	1.81E+07	2.09E+07
	Tight	8.05E+06	7.20E+06	9.03E+06
Arkoma	Conv	4.91E+06	4.44E+06	5.39E+06
	Shale	5.95E+06	5.33E+06	6.66E+06
East Texas	Conv	1.32E+07	1.02E+07	1.69E+07
	Shale	2.10E+07	2.00E+07	2.20E+07
	Tight	5.63E+06	4.69E+06	6.96E+06
Fort Worth	Shale	2.96E+06	2.87E+06	3.05E+06

Basin	Well Type	Mean EUR (Mcf)	p2.5 EUR (Mcf)	p97.5 EUR (Mcf)
Green River	Conv	5.41E+08	4.67E+08	6.03E+08
	Tight	3.59E+06	3.35E+06	3.93E+06
Gulf Coast	Conv	7.38E+06	6.71E+06	8.08E+06
	Shale	7.21E+06	6.73E+06	7.74E+06
	Tight	7.14E+06	6.35E+06	7.95E+06
Permian	Conv	1.42E+07	1.05E+07	1.83E+07
	Shale	9.42E+06	8.89E+06	1.00E+07
Piceance	Tight	1.66E+06	1.60E+06	1.72E+06
San Juan	CBM	6.63E+06	6.33E+06	6.98E+06
	Shale	9.21E+06	3.02E+06	1.50E+07
South Oklahoma	Shale	1.08E+07	9.73E+06	1.19E+07
Strawn	Shale	4.35E+06	4.18E+06	4.53E+06
Uinta	Tight	2.04E+06	1.83E+06	2.35E+06
	Conv	1.18E+06	1.01E+06	1.41E+06

The same process was performed for the oil EUR data from Enverus [15] using data from the same wells as above. **Exhibit 3-4** shows the parameters for oil EUR.

Exhibit 3-4. Oil EUR by basin and well type

Basin	Well Type	Mean EUR (bbl)	p2.5 EUR (bbl)	p97.5 EUR (bbl)
Anadarko	Conv	2.46E+04	2.11E+04	2.86E+04
	Shale	1.09E+05	9.26E+04	1.30E+05
	Tight	4.93E+04	4.10E+04	5.83E+04
Appalachian	Shale	1.78E+04	1.66E+04	1.92E+04
Arkla	Shale	8.54E+01	4.42E+01	1.38E+02
	Conv	7.54E+02	5.70E+02	9.52E+02
	Tight	3.84E+04	3.37E+04	4.31E+04
Arkoma	Conv	1.05E+03	6.46E+02	1.61E+03
	Shale	1.43E+03	5.48E+02	2.47E+03
East Texas	Conv	9.16E+03	7.23E+03	1.16E+04
	Shale	7.18E+02	2.74E+02	1.30E+03
	Tight	3.55E+04	2.30E+04	5.54E+04
Fort Worth	Shale	7.41E+03	6.88E+03	8.01E+03
Green River	Conv	1.09E+03	5.59E+02	2.05E+03
	Tight	3.39E+04	3.05E+04	3.81E+04
Gulf Coast	Conv	1.28E+05	1.11E+05	1.45E+05

Basin	Well Type	Mean EUR (bbl)	p2.5 EUR (bbl)	p97.5 EUR (bbl)
	Shale	1.91E+05	1.73E+05	2.12E+05
	Tight	8.77E+04	6.79E+04	1.08E+05
Permian	Conv	2.54E+05	2.17E+05	2.93E+05
	Shale	4.71E+05	4.35E+05	5.10E+05
Piceance	Tight	4.63E+03	4.41E+03	4.86E+03
San Juan	Conv	9.32E+03	7.82E+03	1.11E+04
	Shale	3.30E+03	1.15E+03	7.21E+03
	CBM	1.12E+02	7.90E+01	1.51E+02
South Oklahoma	Shale	1.13E+05	8.89E+04	1.44E+05
Strawn	Shale	2.90E+02	2.48E+02	3.36E+02
Uinta	Tight	8.96E+03	7.83E+03	1.03E+04
	Conv	4.66E+03	4.08E+03	5.24E+03

The oil and gas EUR parameters are used to allocate burdens between oil and NG. These burdens are energy-allocated within the NG model.

3.3 Vented and Fugitive Emissions

Vented emissions are emissions intentionally released to air, and fugitive emissions are unintentional emissions from equipment malfunctions or infrastructure that is not performing as designed. These two types of emissions occur throughout the NG supply chain. The GHGRP and Inventory of U.S. Greenhouse Gas and Sinks (GHGI) are two data sources that account for most vented and fugitive emissions [12, 19]. These data sources are discussed in the following sections. NETL uses other data sources to account for emissions from liquids unloading and produced water tanks.

3.3.1 Greenhouse Gas Reporting Program

This analysis uses GHGRP and GHGI for the 2020 reporting year to account for the vented and fugitive emissions from the NG supply chain [12, 19]. The GHGRP has an emissions reporting threshold of 25,000 metric tonnes per year of CO_2e per facility (in terms of 100-year IPCC AR4 GWP). Facilities that fall below this threshold are not required to report to the GHGRP [12]. Insufficient data are available for facilities that are below the reporting threshold; this analysis extrapolates the data for the GHGRP facilities to represent the non-GHGRP facilities. Under GHGRP reporting, a facility is typically defined as any physical property, plant, building, structure, source, or piece of stationary equipment located on one or more contiguous or adjacent properties in actual physical contact or separated solely by a public roadway or other public right-of-way and under common ownership or common control that emits or may emit any greenhouse gas [20]. However, for certain NG supply chain stages, the definition of a facility requires additional clarification, as discussed in the bullet points below [21].

- **Production**

  A facility in this stage refers to all petroleum or NG equipment on a single well pad or associated with a single well pad and CO_2 EOR operations that are under common ownership or common control, including leased, rented, or contracted activities by an onshore petroleum and NG production owner or operator, and that are located in a single hydrocarbon basin. Where a person or entity owns or operates more than one well in a basin, then all onshore petroleum and NG production equipment associated with all wells that the person or entity owns or operates in the basin would be considered one facility.

- **Gathering and Boosting**

  A facility in this stage refers to all gathering pipelines and other equipment located along those pipelines that are under common ownership or common control by a gathering and boosting system owner or operator and that are located in a single hydrocarbon basin. Where a person owns or operates more than one gathering and boosting system in a basin (for example, separate gathering lines that are not connected), then all gathering and boosting equipment that the person owns or operates in the basin would be considered one facility. Any gathering and boosting equipment that is associated with a single gathering and boosting system, including leased, rented, or contracted activities, is considered to be under common control of the owner or operator of the gathering and boosting system that contains the pipeline.

- **Processing, Transmission Station, Storage**

  It is worth noting that that the definition of a "facility" in the processing, transmission station, and storage stages of the natural gas supply chain is not reported explicitly under the GHGRP. As a result, "facility" definitions for these three stages are assumed to align with the general definition of a facility discussed above (i.e., any physical property, plant, building, structure, source, or stationary equipment located on one or more contiguous or adjacent properties in actual physical contact or separated solely by a public roadway or other public right-of-way and under common ownership or common control, that emits or may emit any greenhouse gas).

- **Transmission Pipelines**

  A facility in this stage refers to the total U.S. mileage of natural gas transmission pipelines owned and operated by an onshore natural gas transmission pipeline owner or operator. The facility does not include pipelines that are part of any other industry segment.

- **Distribution**

  A facility in this stage refers to the collection of all distribution pipelines and metering-regulating stations that are operated by a local distribution company (LDC) within a single state that is regulated as a separate operating company by a public utility commission or that is operated as an independent, municipally-owned distribution system.

The GHGRP data were retrieved as a series of comma-separated value files from EPA's Envirofacts database [22]. The data consist of facility-level activity and emissions from well completions and workovers, the steady state operation of equipment, and routine maintenance practices such as the blowdown of equipment or pipelines. In addition to activity and emission data, NG throughput data are provided for facilities (except for processing facilities and transmission stations, for which throughput is not reported[5]).

Exhibit 3-5 summarizes the representativeness of the GHGRP data used in this work for NG production [12]. These data represent conventional and unconventional extraction technologies in 14 onshore production basins. In total, they represent 27.3 trillion cubic feet (Tcf) of production; this is 25 percent lower than EIA estimates, which show 36.2 Tcf of marketed NG production in 2020 [11]. This discrepancy between GHGRP data used in this analysis and EIA data is due to various reasons including the GHGRP reporting threshold of 25,000 metric tonnes of CO_2e emissions per facility and omission of smaller production basins from this work.[6] The reporting threshold results in a considerable number of low-producing facilities (and wells) not being accounted for by GHGRP. These low-producing or marginal wells are an area of active research, and this analysis accounts for these wells by assuming a range of production shares, as discussed in **Section 2.3** and **Section 6.4**.

Exhibit 3-5. Representativeness of GHGRP production data[7]

Basin	GHGRP			
	Well Type	Produced NG (Mcf)	Marketed NG (Mcf)	Marketed Oil (bbl)
160/160A – Appalachian[1, 2]	Shale	1.13E+10	1.09E+10	4.12E+07
220 – Gulf Coast	Conv	8.40E+08	7.67E+08	5.04E+07
	Shale	1.12E+09	9.90E+08	2.28E+08
	Tight	2.36E+08	2.17E+08	1.94E+07
230 – Arkla	Conv	9.36E+08	9.29E+08	3.77E+05
	Shale	1.63E+09	1.63E+09	8.74E+04
	Tight	2.54E+08	2.53E+08	1.68E+06
260 – East Texas	Conv	2.31E+08	2.28E+08	1.24E+06
	Shale	1.99E+08	1.98E+08	1.25E+03
	Tight	1.08E+09	1.06E+09	5.55E+06
345 – Arkoma[2]	Conv	1.65E+08	1.55E+08	4.04E+04
	Shale	4.96E+08	4.95E+08	8.60E+03
350 – South Oklahoma Folded Belt[2]	Shale	2.69E+08	2.67E+08	1.39E+07

[5] Throughput values for the processing stage are derived using Form EIA-757 data (see **Section 4.5**), and for transmission stations are estimated using a compressor horsepower-hour per thousand cubic feet of NG relationship derived using EPA's GHGI and EIA's NG delivery data [6, 68].

[6] The NG production basins modeled in this analysis account for 89 percent of NG produced for sales reported to GHGRP for the 2020 data year, which represents 75 percent of total U.S. marketed NG production. Certain smaller NG production basins are omitted to limit the number of scenarios studied in this work. Accounting for all basins reporting to GHGRP leads to an increase in data coverage to 84 percent of total U.S. marketed NG production. As part of future efforts, the inclusion of smaller production basins will be evaluated.

[7] Produced NG represents gross NG withdrawals (i.e., full well-stream volume), whereas marketed NG represents gross withdrawals less gas used for repressuring, quantities vented and flared, etc.

Basin	GHGRP			
	Well Type	Produced NG (Mcf)	Marketed NG (Mcf)	Marketed Oil (bbl)
360 – Anadarko	Conv	5.32E+08	5.14E+08	9.60E+06
	Shale	7.54E+08	7.43E+08	6.08E+07
	Tight	5.87E+08	5.34E+08	2.62E+07
415 – Strawn[2]	Shale	4.26E+08	4.26E+08	2.82E+04
420 – Fort Worth[2]	Shale	2.58E+08	2.49E+08	6.40E+05
430 – Permian[2]	Conv	2.88E+09	2.75E+09	5.54E+08
	Shale	2.07E+09	1.99E+09	2.87E+08
535 – Green River	Conv	2.71E+08	1.74E+07	5.68E+04
	Tight	7.60E+08	7.43E+08	9.82E+06
575 – Uinta	Conv	7.22E+06	7.17E+06	4.58E+04
	Tight	1.71E+08	1.66E+08	1.36E+06
580 – San Juan[2]	CBM	2.76E+08	2.63E+08	1.72E+05
	Shale	3.14E+08	3.03E+08	2.95E+06
595 – Piceance[2]	Tight	5.28E+08	5.27E+08	1.15E+06
Total	**All**	**2.86E+10**	**2.73E+10**	**1.32E+09**

[1] The Appalachian techno-basin modeled in this work represents aggregated GHGRP-reported data for Appalachian basin 160 and Appalachian basin 160A (Eastern Overthrust).
[2] These basins represent aggregated shale and tight production shares classified under either the shale or tight category (depending on the basin) to limit the number of scenarios modeled in this work.

Exhibit 3-6 summarizes the representativeness of the GHGRP data for NG gathering and boosting [12]. It represents 285 gathering and boosting facilities that align with the 14 onshore production basins within the scope of this analysis. GHGRP defines a gathering and boosting facility as a gathering and boosting network owned by an operator in an entire basin, not a single gathering and boosting station. These data have two limitations:

- The count of gathering and boosting stations within a facility (as defined under GHGRP) is not available.
- Gathering and boosting facilities cannot be further stratified into facilities that support specific production technologies (conventional, shale, tight, and CBM extraction).

Exhibit 3-6. Representativeness of GHGRP gathering and boosting data

Basin	Gas Received (Mcf)	Gas Transferred (Mcf)	Marketed Production (Mcf)
160/160A – Appalachian	1.51E+10	1.42E+10	1.09E+10
220 – Gulf Coast (LA, TX)	4.55E+09	3.38E+09	1.97E+09
230 – Arkla	2.55E+09	2.06E+09	2.81E+09
260 – East Texas	2.08E+09	1.81E+09	1.49E+09
345 – Arkoma	1.12E+09	1.02E+09	6.51E+08
350 – South Oklahoma Folded Belt	5.24E+08	5.09E+08	2.80E+08

Basin	Gas Received (Mcf)	Gas Transferred (Mcf)	Marketed Production (Mcf)
360 – Anadarko	2.47E+09	2.25E+09	1.79E+09
415 – Strawn	7.00E+08	5.47E+08	4.31E+08
420 – Fort Worth	4.39E+08	4.00E+08	2.69E+08
430 – Permian	9.04E+09	8.08E+09	4.74E+09
535 – Green River	1.10E+09	1.08E+09	7.60E+08
575 – Uinta	2.16E+08	2.10E+08	1.74E+08
580 – San Juan	9.52E+08	9.64E+08	7.13E+08
595 – Piceance	1.04E+09	1.18E+09	5.28E+08
Total	**4.19E+10**	**3.77E+10**	**2.75E+10**

The GHGRP appears to double-count gathering and boosting stage NG throughput. GHGRP shows that 43.2 Tcf of NG was gathered by the gathering and boosting stations in the United States in 2020 [12]. This is greater than the 36.2 Tcf of total marketed NG production in the United States in 2020 as reported by EIA [11]. As per EPA, the reported quantities of gas received frequently exceed the amount of gas produced in a basin as the "volume of gas received might be counted more than once as it moves from one system to another system within the same basin (i.e., is received multiple times)." To mitigate this double-counting, this analysis scales down the gathering and boosting stage throughput for all basins by 16 percent, except for Permian, Gulf Coast, and Anadarko, which are not adjusted. This method is consistent with the gathering and boosting adjustments proposed by EPA for GHGI [19].

Exhibit 3-7 summarizes the representativeness of the GHGRP data for processing, transmission and storage, and distribution. It compares the GHGRP parameters to corresponding parameters used by the GHGI and EIA. Key comparisons between processing, transmission and storage, and distribution are as follows [12, 19]:

- **Processing:** GHGRP does not provide NG throughput data for processing facilities, so the throughput representativeness of the GHGRP data is unknown. On a facility-count basis, GHGRP represents 69 percent of the facility count accounted for by the GHGI.
- **Transmission Stations:** GHGRP does not provide throughput data for transmission, so the throughput representativeness of the GHGRP data is unknown. On a facility-count basis, GHGRP represents 28 percent of transmission compressor stations (when compared to GHGI data).
- **Storage:** On a capacity basis, GHGRP represents 46 percent of the storage capacity (when compared to EIA data).
- **Transmission Pipelines:** GHGI and EIA do not provide adequate points of comparison to the GHGRP delivered volumes by transmission pipeline. On a pipeline mileage basis, GHGRP represents 63 percent and 62 percent of the pipeline length reported by GHGI and EIA, respectively.

- **Distribution:** Based on EIA data, 14.7 Tcf of NG was estimated to be delivered by LDCs to consumers in 2020. Thus, GHGRP represents 88 percent of U.S. NG distribution.

Through statistical bootstrapping of GHGRP parameters, the GHGRP data are extrapolated to be representative of an average unit of NG traversing the various stages of the U.S. NG supply chain. **Section 5.2** discusses the process of statistical bootstrapping in detail and highlights that this analysis aims to understand the emissions profile associated with an average unit of U.S. NG while accounting for the uncertainty around the mean, as opposed to explaining the emissions intensity associated with a randomly selected unit of NG.

The GHGRP data for venting are shown in **Exhibit 3-8** through **Exhibit 3-12**, and the GHGRP data for fugitives are shown in **Exhibit 3-13** through **Exhibit 3-15** [12]. The mean values represent production-weighted averages. In the average activity factors, wells that produce more gas in the study year are assigned a greater weighting. The 95 percent confidence intervals represent those for the mean. The method for generating them is discussed in **Section 5**.

Exhibit 3-8 through **Exhibit 3-12** show venting data for all supply chain stages. The production, gathering, and processing stages comprise too much data to be shown here. Thus, **Exhibit 3-8** shows data only for Appalachian shale production, **Exhibit 3-9** shows data only for Appalachian gathering and boosting, and

Exhibit 3-10 shows data only for Appalachian shale processing. In addition, **Exhibit 3-11** and **Exhibit 3-12** show data for U.S. average transmission through distribution stages. **Appendix A** (available in the release package published along with this report) provides venting data for production, gathering and boosting, and processing in all upstream study regions. It also provides regionalized transmission through distribution stage venting data for the various downstream study regions (Midwest, Northeast, Southwest, Southeast, Rocky Mountain, and Pacific).

Exhibit 3-7. Representativeness of GHGRP processing, transmission and storage, and distribution data

Stage		Parameter	Unit	GHGRP							GHGI	EIA
				Pacific	Rocky Mountain	Southwest	Southeast	Midwest	Northeast	Total		
Processing		NG processed	Mcf							**N/A**	N/A	2.47E+10
		Facilities	count							**462**	667	N/A
Transmission & Storage	Transmission stations	Compressor stations	count	27	38	154	202	156	67	**644**	2,267	N/A
	Storage	NG withdrawn	Mcf	1.03E+08	4.34E+07	3.32E+09	5.25E+08	4.23E+08	2.55E+08	**1.60E+09**	N/A	3.76E+09
		NG storage capacity	Mcf	3.38E+08	1.20E+08	9.24E+09	1.18E+09	1.66E+09	4.42E+08	**4.26E+09**	N/A	9.26E+09
	Transmission pipelines	NG delivered	Mcf							**4.62E+10**	N/A	N/A
		Pipeline length	miles							**1.91E+05**	3.02E+05	3.06E+05
Distribution		NG delivered	Mcf	1.89E+09	8.39E+08	1.11E+09	1.93E+09	4.52E+09	2.66E+09	**1.30E+10**	N/A	1.47E+10

Exhibit 3-8. Vented emissions from production (Appalachian shale)

Emission Source		Parameter Type	Unit	p2.5	Mean	p97.5
Hydraulically fractured (HF) completions and workovers	HF completions (flaring)	CH_4 emissions	tonnes/facility-yr	6.34E-03	5.00E-01	1.10E+00
	HF completions (no flaring)	CH_4 emissions	tonnes/facility-yr	9.13E+01	2.09E+02	3.52E+02
	HF workovers (flaring)	CH_4 emissions	tonnes/facility-yr	N/A	N/A	N/A
	HF workovers (no flaring)	CH_4 emissions	tonnes/facility-yr	N/A	N/A	N/A
Conventional completions and workovers	Conventional completions (flaring)	CH_4 emissions	tonnes/facility-yr	N/A	N/A	N/A
	Conventional completions (no flaring)	CH_4 emissions	tonnes/facility-yr	N/A	N/A	N/A
	Conventional workovers (flaring)	CH_4 emissions	tonnes/facility-yr	N/A	N/A	N/A
	Conventional workovers (no flaring)	CH_4 emissions	tonnes/facility-yr	9.38E-01	2.23E+00	3.98E+00
Pneumatic devices	High bleed	Activity factor (AF)	hr/yr	0.00E+00	2.10E+02	9.41E+02
			count/facility	0.00E+00	2.24E+00	1.01E+01
		Emission factor (EF)	kg CH_4/hr-device		7.16E-01	
	Intermittent bleed	AF	hr/yr	4.84E+03	6.06E+03	7.20E+03
			count/facility	2.52E+03	3.63E+03	4.84E+03
		EF	kg CH_4/hr-device		2.59E-01	
	Low bleed	AF	hr/yr	6.53E+03	7.54E+03	8.40E+03
			count/facility	3.65E+02	6.33E+02	9.28E+02
		EF	kg CH_4/hr-device		2.67E-02	
	Pneumatic pumps	AF	hr/yr	2.18E+03	3.58E+03	5.01E+03
			count/facility	3.03E+01	5.80E+01	9.62E+01
		EF	kg CH_4/hr-device		2.55E-01	
Dehydrators	Small glycol	CH_4 emissions	kg CH_4/facility-yr	2.46E+02	6.88E+02	1.22E+03
	Desiccant	CH_4 emissions	kg CH_4/facility-yr	5.57E+01	2.38E+02	4.37E+02
	Large glycol	CH_4 emissions	kg CH_4/facility-yr	2.24E+05	4.23E+05	6.47E+05
AGR		CO_2 emissions	tonnes CO_2/yr	N/A	N/A	N/A
Reciprocating compressors		AF	count/facility	3.15E+01	5.52E+01	7.99E+01
Compressor blowdowns		AF	wells/facility	9.43E+02	1.27E+03	1.59E+03
			compressor/well		1.06E-01	
		EF	kg CH_4/ compressor-yr		7.74E+01	
Pressure relief valve (PRV) upset		AF	count/facility	9.43E+02	1.27E+03	1.59E+03
		EF	kg CH_4/event		7.00E-01	
Vessel blowdowns		AF	wells/facility	9.43E+02	1.27E+03	1.59E+03
			heater/well		2.17E-01	
			separator/well		6.72E-01	
			dehydrator/well		3.75E-02	
		EF	kg CH_4/vessel-yr		1.60E+00	

Exhibit 3-9. Vented emissions from gathering and boosting (Appalachian shale)

Emission Source		Parameter Type	Unit	p2.5	Mean	p97.5
Pneumatic devices	High bleed	AF	count/facility	1.19E+01	1.69E+01	2.23E+01
			hr/yr	3.55E+03	4.63E+03	5.75E+03
		EF	kg CH_4/hr-device	3.62E-01	7.24E-01	1.09E+00
	Intermittent bleed	AF	count/facility	2.50E+02	3.45E+02	4.41E+02
			hr/yr	7.08E+03	7.83E+03	8.42E+03
		EF	kg CH_4/hr-device	1.45E-01	2.43E-01	3.42E-01
	Low bleed	AF	count/facility	7.73E+01	1.12E+02	1.51E+02
			hr/yr	4.73E+03	5.72E+03	6.81E+03
		EF	kg CH_4/hr-device	4.69E-02	6.84E-02	8.99E-02
	Pneumatic pumps	AF	count/facility	5.47E+01	8.46E+01	1.15E+02
			hr/yr	4.72E+03	5.64E+03	6.55E+03
		EF	kg CH_4/hr-device	6.01E-02	1.67E-01	2.74E-01
Dehydrators	Small glycol	CH_4 emissions	tonnes/facility-yr	5.35E-01	9.77E-01	1.56E+00
	Desiccant	CH_4 emissions	tonnes/facility-yr	2.35E-02	1.48E-01	3.08E-01
	Large glycol	CH_4 emissions	tonnes/facility-yr	5.95E+02	8.25E+02	1.09E+03
AGR		CO_2 emissions	tonnes/yr	0.00E+00	3.20E+00	7.60E+00
		EF	scf CH_4/hr-device	2.03E+00	3.61E+00	5.19E+00
Blowdowns	Other	CH_4 emissions	tonnes/facility-yr	4.53E+00	7.32E+00	1.02E+01
	Compressors	CH_4 emissions	tonnes/facility-yr	3.21E+02	4.70E+02	6.34E+02
	Emergency shutdowns	CH_4 emissions	tonnes/facility-yr	1.46E+02	2.38E+02	3.36E+02
	Facility piping	CH_4 emissions	tonnes/facility-yr	8.21E+01	1.91E+02	3.44E+02
	Pig launching and receiving	CH_4 emissions	tonnes/facility-yr	4.37E+01	6.00E+01	7.98E+01
	Pipeline venting	CH_4 emissions	tonnes/facility-yr	1.61E+01	2.68E+01	3.92E+01
	Scrubbers/strainers	CH_4 emissions	tonnes/facility-yr	1.15E+01	1.86E+01	2.65E+01

Exhibit 3-10. Vented emissions from processing (Appalachian shale)

Emission Source		Parameter Type	Unit	p2.5	Mean	p97.5
Gas processing	AGR	CO_2 emissions	tonnes/facility-yr	0.00E+00	5.01E+01	1.31E+02
		EF	kg CH_4/kg NG	3.73E-05		
	Desiccant dehydrator	CH_4 emissions	tonnes/facility-yr	0.00E+00	8.60E-02	2.06E-01
	Large glycol dehydrators	CH_4 emissions	tonnes/facility-yr	0.00E+00	2.63E-01	7.71E-01
Blowdowns	Other	CH_4 emissions	tonnes/facility-yr	N/A	N/A	N/A
	Compressors	CH_4 emissions	tonnes/facility-yr	1.04E+00	8.83E+00	2.10E+01
	Emergency shutdowns	CH_4 emissions	tonnes/facility-yr	0.00E+00	6.21E-02	1.83E-01
	Facility piping	CH_4 emissions	tonnes/facility-yr	8.64E-03	1.30E-01	3.07E-01
	Pig launching and receiving	CH_4 emissions	tonnes/facility-yr	1.04E-01	4.19E+00	1.12E+01
	Scrubbers/strainers	CH_4 emissions	tonnes/facility-yr	4.44E-03	3.83E-02	9.45E-02
Flaring		AF	scf sent to flare/facility-yr	0.00E+00	1.19E+07	3.19E+07
Compressors	Centrifugal	Energy	HPh/facility-yr	6.82E+06	3.10E+07	6.25E+07
		CH_4 emissions	tonnes/facility-yr	3.58E-02	3.82E-01	8.88E-01
	Reciprocating	Energy	HPh/facility-yr	1.59E+08	3.24E+08	5.47E+08
		CH_4 emissions	tonnes CH_4/yr	2.98E+01	9.69E+01	2.04E+02
Equipment leaks		CH_4 emissions	tonnes CH_4/yr	1.48E+01	2.69E+01	4.15E+01

Exhibit 3-11. Vented emissions from transmission stations, storage, and transmission pipelines (U.S. average)

Stage	Emission Source		Parameter Type	Unit	p2.5	Mean	p97.5
Transmission Station	Pneumatic devices	High bleed	AF	count/facility	1.08E+00	1.39E+00	1.73E+00
			EF	kg CH_4/ controller-yr	7.25E+02	8.41E+02	9.58E+02
		Intermittent bleed	AF	count/facility	3.24E+01	3.58E+01	3.94E+01
			EF	kg CH_4/ controller-yr	1.86E+02	2.23E+02	2.72E+02
		Low bleed	AF	count/facility	1.46E+00	1.86E+00	2.32E+00
			EF	kg CH_4/ controller-yr	5.55E+01	6.55E+01	7.70E+01
	Blowdowns	Other	CH_4 emissions	tonnes/facility-yr	1.05E+01	1.85E+01	2.81E+01
		Compressors	CH_4 emissions	tonnes/facility-yr	4.12E+01	4.78E+01	5.49E+01
		Emergency shutdowns	CH_4 emissions	tonnes/facility-yr	7.23E+00	1.54E+01	2.58E+01
		Facility piping	CH_4 emissions	tonnes/facility-yr	1.07E+01	1.66E+01	2.37E+01
		Pig launching and receiving	CH_4 emissions	tonnes/facility-yr	4.89E-01	8.15E-01	1.19E+00
		Pipeline venting	CH_4 emissions	tonnes/facility-yr	3.45E+00	5.96E+00	8.95E+00
		Scrubbers/strainers	CH_4 emissions	tonnes/facility-yr	5.31E-01	9.18E-01	1.39E+00
	Dehydrators	Dehydrator vents	EF	kg CH_4/MMcf		1.81E+00	
			AF	MMcf sent to dehydrator/facility-yr		1.19E+06	
	Compressors	Centrifugal	Energy	HPh/facility-yr	1.33E+08	1.47E+08	1.62E+08
			CH_4 emissions	tonnes/facility-yr	1.13E+02	1.42E+02	1.75E+02
		Reciprocating	Energy	HPh/facility-yr	3.02E+07	3.46E+07	3.90E+07
			CH_4 emissions	tonnes/facility-yr	2.38E+02	2.94E+02	3.54E+02
	Flaring	Flare stacks	CH_4 emissions	tonnes/facility-yr	1.50E-03	2.37E-02	6.16E-02

Stage	Emission Source		Parameter Type	Unit	p2.5	Mean	p97.5
Storage	Pneumatic devices	High bleed	AF	count/facility	5.11E+00	1.44E+01	2.61E+01
			AF	hr/yr	1.52E+03	2.44E+03	3.55E+03
		Intermittent bleed	AF	count/facility	4.39E+01	5.92E+01	7.47E+01
			AF	hr/yr	6.27E+03	7.50E+03	8.72E+03
		Low bleed	AF	count/facility	5.40E+00	9.97E+00	1.48E+01
			AF	hr/yr	3.38E+03	4.49E+03	5.57E+03
	Compressors	Centrifugal	Energy	HPh/facility-yr	1.25E+06	6.21E+06	1.80E+07
			CH_4 emissions	tonnes/facility-yr	6.74E-01	3.85E+00	1.00E+01
		Reciprocating compressor	Energy	HPh/facility-yr	3.41E+07	4.78E+07	6.44E+07
			CH_4 emissions	tonnes/facility-yr	6.20E+01	1.53E+02	3.23E+02
	Dehydrators	Dehydrator vents	EF	kg CH_4/MMcf dehydrated		2.26E+00	
			AF	MMcf dehydrated/facility-yr		1.85E+06	
	Station venting		EF	kg CH_4/station-yr		8.40E+04	
			AF	station/facility		1.00E+00	
	Flaring	CH_4 emissions	CH_4 emissions	tonnes/facility-yr	1.35E-03	6.44E-02	1.61E-01
Transmission Pipeline	All other pipeline segments with a physical volume greater than or equal to 50 cubic feet		CH_4 emissions	tonnes/facility-yr	5.72E+02	1.31E+03	2.17E+03
	Emergency shutdowns including pipeline incidents		CH_4 emissions	tonnes/facility-yr	4.31E+01	1.40E+02	2.52E+02
	Equipment replacement or repair		CH_4 emissions	tonnes/facility-yr	2.35E+02	4.03E+02	5.98E+02
	New construction or modification of pipelines including commissioning and change of service		CH_4 emissions	tonnes/facility-yr	5.93E+02	9.17E+02	1.30E+03
	Operational precaution during activities		CH_4 emissions	tonnes/facility-yr	4.03E+01	1.20E+02	2.32E+02
	Pipeline integrity work		CH_4 emissions	tonnes/facility-yr	1.02E+03	1.46E+03	1.93E+03
	Traditional operations or pipeline maintenance		CH_4 emissions	tonnes/facility-yr	4.88E+02	8.80E+02	1.39E+03

Exhibit 3-12. Vented emissions from distribution (U.S. average)

Emission Source	Parameter Type	Unit	Mean
PRV releases	AF	miles/kg NG	4.86E-06
	EF	kg CH_4/mile	9.63E-01
Pipeline blowdowns	AF	miles/kg NG	8.30E-06
	EF	kg CH_4/mile	1.96E+00
Mishaps (dig ins)	AF	miles/kg NG	8.30E-06
	EF	kg CH_4/mile	3.06E+01

Exhibit 3-13 through **Exhibit 3-15** show fugitive emission parameters for all supply chain stages. The production, gathering, and processing stages comprise too much data to be shown here, so **Exhibit 3-13** shows fugitive data only for Appalachian shale production, and **Exhibit 3-14** shows fugitive data only for Appalachian gathering and boosting, and processing. It is worth noting that gathering- and boosting-stage fugitive emissions are classified into gas service and gathering pipelines emissions categories. Gas service equipment solely supports the NG value stream, whereas gathering pipelines support both the lease condensate and NG value streams [23]. In addition, **Exhibit 3-15** shows fugitive data for U.S. average transmission through distribution stages. **Appendix A** (available in the release package published along with this report) provides fugitive data for production, gathering and boosting, and processing in all upstream study regions. It also provides regionalized transmission- through distribution-stage fugitive data for the various downstream study regions (Midwest, Northeast, Southwest, Southeast, Rocky Mountain, and Pacific).

In some cases, zeroes are reported to the GHGRP for fugitive emission parameters [12]. As shown in **Exhibit 3-13**, no flanges are reported for Appalachian shale production; flanges are a type of connector, so some producers include flanges in their counts for connectors. In other instances (as shown by the detailed parameter tables in **Appendix A** [available in the release package published along with this report]), zero emissions are reported for non-zero equipment counts; this exemplifies instances where operators reported equipment counts even though they did not detect any leaks.

Exhibit 3-13. Fugitive emissions from production (Appalachian shale)

Emission Source	Parameter Type	Unit	p2.5	Mean	p97.5
Connectors	AF	count/facility	1.80E+04	2.97E+04	4.18E+04
	AF	hr/yr	3.75E+03	5.36E+03	6.82E+03
	EF	kg CH_4/device-hr	5.74E-05	6.69E-05	8.24E-05
Flanges	AF	count/facility	N/A	N/A	N/A
	AF	hr/yr	N/A	N/A	N/A
	EF	kg CH_4/device-hr	N/A	N/A	N/A
Open-ended lines	AF	count/facility	1.80E+02	3.36E+02	5.20E+02
	AF	hr/yr	3.74E+03	5.36E+03	6.82E+03

Emission Source	Parameter Type	Unit	p2.5	Mean	p97.5
	EF	kg CH_4/device-hr	1.17E-03	1.37E-03	1.68E-03
PRVs	AF	count/facility	4.44E+01	1.03E+02	1.76E+02
	AF	hr/yr	3.74E+03	5.35E+03	6.82E+03
	EF	kg CH_4/device-hr	6.77E-04	8.36E-04	1.12E-03
Valves	AF	count/facility	4.13E+03	6.77E+03	9.52E+03
	AF	hr/yr	3.75E+03	5.36E+03	6.82E+03
	EF	kg CH_4/device-hr	5.21E-04	6.05E-04	7.44E-04
Other	AF	count/facility	N/A	N/A	N/A
	AF	hr/yr	N/A	N/A	N/A
	EF	kg CH_4/device-hr	N/A	N/A	N/A

Exhibit 3-14. Fugitive emissions from gathering and boosting and from processing (Appalachian shale)

Stage	Emission Source		Parameter Type	Unit	p2.5	Mean	p97.5
Gathering and Boosting	Gas Service	Connectors	EF	scf/hr/ component	3.00E-03		
			Number of components	count/facility	1.40E+04	2.04E+04	2.71E+04
			Operating hours	hr/yr	6.59E+03	7.35E+03	8.07E+03
		Open-ended lines	CH_4 emissions	tonnes/facility-yr	3.25E-01	4.58E-01	6.06E-01
		PRVs	EF	scf/hr/ component	1.41E+00		
			Number of components	count/facility	2.91E+01	4.05E+01	5.37E+01
			Operating hours	hr/yr	6.14E+03	7.00E+03	7.77E+03
		Valves	EF	scf/hr/ component	4.20E-02		
			Number of components	count/facility	3.55E+03	5.21E+03	6.95E+03
			Operating hours	hr/yr	6.59E+03	7.35E+03	8.07E+03
	Pipelines	Cast iron gathering pipeline	CH_4 emissions	tonnes/facility-yr	N/A	N/A	N/A
		Plastic/composite gathering pipeline	CH_4 emissions	tonnes/facility-yr	1.71E+01	3.53E+01	6.14E+01
		Protected steel gathering pipeline	CH_4 emissions	tonnes/facility-yr	5.34E+01	8.42E+01	1.26E+02
		Unprotected steel gathering pipeline	CH_4 emissions	tonnes/facility-yr	5.02E+01	8.28E+01	1.17E+02
Processing	Equipment leaks		CH_4 emissions	tonnes/facility-yr	1.48E+01	2.69E+01	4.15E+01

Exhibit 3-15. Fugitive emissions from transmission through distribution (U.S. average)

Stage	Emission Source	Parameter Type	Unit	p2.5	Mean	p97.5
Transmission Station	Transmission storage leaks	CH_4 emissions	tonnes/facility-yr	6.10E+00	7.60E+00	9.25E+00
	Equipment leaks	CH_4 emissions	tonnes/facility-yr	1.65E+01	1.88E+01	2.11E+01
Storage	Station leaks	CH_4 emissions	tonnes/facility-yr	2.10E+01	3.27E+01	4.60E+01
	Well leaks	CH_4 emissions	tonnes/facility-yr	2.13E+01	3.06E+01	4.15E+01
Transmission Pipeline	Pipeline fugitives	AF	miles/facility	6.12E+03	7.21E+03	8.29E+03
		EF	kg CH_4/kg NG-mile		2.10E-11	
Distribution	Transmission-distribution (T-D) transfer stations (above ground)	CH_4 emissions	tonnes/facility-yr	5.31E+00	9.79E+00	1.57E+01
	T-D transfer stations (below ground)	CH_4 emissions	tonnes/facility-yr	2.43E+01	3.33E+01	4.39E+01
	Distribution mains	CH_4 emissions	tonnes/facility-yr	4.58E+03	5.44E+03	6.37E+03
	Residential meters	AF	device/facility-kg NG		2.06E-04	
		EF	kg CH_4/device		1.49E+00	
	Commercial meters	AF	device/facility-kg NG		2.32E-05	
		EF	kg CH_4/device	3.53E+01	5.74E+01	8.25E+01
	Industrial meters	AF	device/facility-kg NG		7.62E-07	
		EF	kg CH_4/device	6.48E+01	1.18E+02	1.80E+02

Note: The “distribution mains” category includes emissions from cast iron, plastic, protected steel, and unprotected steel distribution pipelines.

3.3.2 Inventory of U.S. Greenhouse Gas Emissions and Sinks

There are emission sources in the NG supply chain for which the GHGRP does not account but for which the GHGI does account. **Exhibit 3-16** shows the EFs and AFs for these emission sources, as well as the corresponding NG throughput for each emission source. **Exhibit 3-17** provides the EFs and AFs for the various emission sources that have been newly incorporated in the NETL NG model based on comparison with EPA’s GHGI [6] as discussed in **Section 9.1**.

Exhibit 3-16. GHGI EFs and AFs and corresponding NG throughput for 2020 data year

Stage (or substage)	Emission Source	Vent	Fugitive	Emissions				NG Throughput	
				GHGI Emission Factor	Unit (annualized)	Activity Factor	Unit	Throughput	Unit
Production	Well drilling	•		51	kg CH_4/completed well	*	Completed well	EUR*	Bcf/well-life
	Compressor blowdowns	•		77	kg CH_4/compressor	0.106	Compressor/well	Annual production*	Mcf/basin-yr
						*	Well		
	PRV upsets	•		0.7	kg CH_4/PRV	*	Well	Annual production*	Mcf/basin-yr
	Vessel blowdowns	•		1.6	kg CH_4/vessel	*	Well	Annual production*	Mcf/basin-yr
Gathering	Mishaps	•		14	kg CH_4/mile	81	Well/facility	Annual production*	Mcf/basin-yr
						0.67	Mile/well		
Processing	Pneumatics	•		3,173	kg CH_4/facility	1	Facility	Regionalized throughput*	Bcf/facility-yr
Transmission	Dehydrator vents	•		1.8	kg CH_4/MMscf NG dehydrated	1.44E+06	MMscf NG	Regionalized throughput*	Tcf transmission
Storage	Dehydrator vents	•		2.3	kg CH_4/MMscf dehydrated	1.99E+06	MMscf dehydrated	Regionalized storage capacity	Tcf capacity
	Station venting	•		84,000	kg CH_4/station	*	Bcf station capacity	Regionalized storage capacity	Tcf capacity
Distribution	Customer meters (residential)		•	1.5	kg CH_4/meter	2.06E-04	Meter/kg NG	Regionalized NG distributed volume	Tcf distributed
	PRV upsets	•		0.9	kg CH_4/mile	4.86E-06	Mile/kg NG	Regionalized NG distributed volume	Tcf distributed
	Pipeline blowdowns	•		0.9	kg CH_4/mile	8.30E-06	Mile/kg NG	Regionalized NG distributed volume	Tcf distributed
	Mishaps (dig ins)	•		30	kg CH_4/mile	8.30E-06	Mile/kg NG	Regionalized NG distributed volume	Tcf distributed

*In some instances, throughput is variable across basins and extraction technologies. This variability is based on NETL's stratification of the data by basins and extraction technologies. Variability in AFs is based on stratification of GHGRP data as shown in **Exhibit 3-8** through **Exhibit 3-15** [12].

Exhibit 3-17. GHGI EFs and AFs for newly incorporated emission categories for 2020 data year

Stage	Emission Source	Parameter Type	Unit	Value
Production	Separators	AF	separators count	2.91E+05
		CH_4 EF	kg/separator	3.83E+02
		CO_2 EF	kg/separator	6.08E+01
	Meters/piping	AF	meters count	3.44E+05
		CH_4 EF	kg/meter	2.03E+02
		CO_2 EF	kg/meter	2.93E+01
Gathering and Boosting	Atmospheric tanks	AF	tanks count	4.36E+04
		CH_4 EF	kg/tank	5.61E+03
		CO_2 EF	kg/tank	2.16E+04
	Yard piping	AF	station count	7.43E+03
		CH_4 EF	kg/station	1.26E+04
		CO_2 EF	kg/station	1.51E+03
Transmission and Storage	Metering & regulating (M&R) – transmission company interconnect	AF	station count	2.69E+03
		CH_4 EF	kg/station	2.80E+04
		CO_2 EF	kg/station	8.25E+02
	M&R – farm taps & direct sales	AF	station count	7.97E+04
		CH_4 EF	kg/station	2.19E+02
		CO_2 EF	kg/station	6.46E+00

3.3.3 Liquids Unloading

The GHGRP accounts for emissions from liquids unloading, but this analysis uses an alternate approach for calculating these emissions. Data from recent measurement campaigns demonstrate that the emissions from liquids unloading are dominated by a small fraction of wells with high unloading frequencies [24].

NETL simulated liquids-unloading emissions using an engineering-based equation that accounts for different plunging technologies, well characteristics, and formation characteristic. The following equations represent the NG emission rates for wells that unload without plunger lifts (**Equation 3-1**) and with plunger lifts **(Equation 3-2**).

$$E_{non-plunger} = [(V \times (0.37 \times 10^{-3}) \times CD^2 \times WD \times SP) + V\,(SFR \times (HR - 1.0) \times Z)]$$ ***Equation 3-1***

$$E_{plunger-lift} = [(V \times (0.37 \times 10^{-3}) \times TD^2 \times WD \times SP) + V\,(SFR \times (HR - 0.5) \times Z)]$$ ***Equation 3-2***

Where:

V = venting frequency

CD = casing diameter

TD = tubing diameter

WD = well depth

SP = shut-in pressure

SFR = standard flow rate

HR = venting duration

Z = dimensionless constant

Equation 3-1 and **Equation 3-2** calculate the whole gas emissions from unloading events. In addition to these equations, it is necessary to apply the volumetric fraction of CH_4 in produced NG and volumetric density of CH_4 to convert whole gas emissions to CH_4 emissions. It is also necessary to use co-production allocation to apportion liquids-unloading emissions between oil and NG. Here, the unloading emission rates are expressed in terms of throughput normalized methane emission rate (TNME), which divides CH_4 emissions by the corresponding NG production rate.

Data from the American Petroleum Institute (API) and America's Natural Gas Alliance (ANGA) (now defunct; merged with API in 2015), Enverus (formerly DI Desktop), the 2020 GHGRP, and peer-reviewed literature are used to parameterize key model inputs [25, 15, 12]. Well-level GHGRP and Enverus data are each grouped and joined by county and well type, and these grouped data are used to estimate emissions using **Equation 3-1** and **Equation 3-2**. County-level emission estimates are then further aggregated to the basins and National Energy Modeling System regions.

Exhibit 3-18 shows the basin-level TNME for liquids unloading, organized by conventional and unconventional extraction technologies. Additional information can be found in **Appendix D** (available in the release package published along with this report).

Exhibit 3-18. TNME for liquids unloading by basin and conventional and unconventional wells

Basin	TNME – Conventional			TNME – Unconventional		
	p2.5	Mean	p97.5	p2.5	Mean	p97.5
Anadarko	0.155%	0.158%	0.160%	0.024%	0.025%	0.026%
Appalachian	--	--	--	0.067%	0.069%	0.072%
Arkla	0.051%	0.053%	0.054%	0.059%	0.064%	0.069%
Arkoma	0.447%	0.455%	0.463%	0.131%	0.133%	0.136%
East Texas	0.072%	0.076%	0.079%	0.044%	0.046%	0.048%
Fort Worth	--	--	--	0.096%	0.101%	0.105%
Green River	0.056%	0.059%	0.062%	--	--	--
Gulf Coast	0.038%	0.041%	0.043%	0.029%	0.030%	0.030%
Permian	0.003%	0.004%	0.004%	--	--	--
Piceance	--	--	--	0.044%	0.047%	0.049%
San Juan	--	--	--	0.030%	0.031%	0.032%

Basin	TNME – Conventional			TNME – Unconventional		
	p2.5	Mean	p97.5	p2.5	Mean	p97.5
South Oklahoma	--	--	--	0.014%	0.014%	0.015%
Strawn	--	--	--	0.015%	0.017%	0.018%
Uinta	0.095%	0.101%	0.106%	--	--	--

3.3.4 Produced Water Tanks

Produced water tanks may emit CH_4 entrained in water that is co-extracted with NG or lifted from wellbores during liquids unloading. CH_4 is not highly soluble in water, so CH_4 concentration in water in produced water tanks is expected to be lower than CH_4 concentration in condensates in condensate storage tanks. Nonetheless, for completeness, this analysis includes CH_4 emissions from produced water tanks and applies an EF of 0.0142 kg CH_4 per barrel of water sent to produced water tanks [26].

3.3.5 Offshore Extraction

Emissions from offshore production are estimated using GHGRP data [12]. GHGRP reports fugitive and venting emissions from various sources. Fugitive emission sources include open-ended lines, connectors, flanges, valves, pumps, and other sources. The offshore venting emissions captured by the model include emissions sources such as dehydrators and pneumatic pumps. In addition to fugitives and venting, flaring emissions reported by GHGRP are also incorporated into the model for offshore production. **Exhibit 3-19** provides the fugitive and venting emissions data for the Alaska and GoM offshore scenarios.

Exhibit 3-19. Offshore venting and fugitive emissions

Emission Category	Emission Source	Unit	Alaska Offshore	GoM Offshore
Fugitive Emissions	Open-ended lines	tonnes CH_4/yr	0.00E+00	2.18E-02
	Connectors	tonnes CH_4/yr	2.21E+00	1.33E+00
	Flanges	tonnes CH_4/yr	9.17E+00	4.08E+00
	Valves	tonnes CH_4/yr	5.96E+01	3.52E+01
	Pumps	tonnes CH_4/yr	7.37E-02	1.35E-02
	Others	tonnes CH_4/yr	1.28E+02	4.39E+01
Venting Emissions	Dehydrators	tonnes CH_4/yr	2.63E+00	1.26E+00
	Pneumatic pumps	tonnes CH_4/yr	5.91E-01	3.29E+01

3.4 Combustion Emissions

The flaring of vented NG, which converts the various hydrocarbons in NG (including CH_4) to CO_2, is preferable to venting, from a GHG perspective. Flaring is prevalent in the production stage. Combustion emissions also come from fuel combusted in compressors, heaters, and other equipment across the NG supply chain.

3.4.1 Flaring

The combustion products of flaring at NG production and processing sites include CO_2, CH_4, and nitrous oxide (N_2O). Processed NG has a higher share of CH_4 than production gas because it has been treated to remove acid gas, water, and NGLs (in the form of non-methane volatile organic compounds) [27]. The mass composition of NG is used to calculate the composition of vented and flared gas. Flaring is modeled with a 98 percent destruction efficiency, meaning that 98 percent of carbon in the flared gas is converted to CO_2 [28]. The CH_4 emissions from flaring are equal to the 2 percent portion of gas that is not converted to CO_2; N_2O emissions from flaring are based on EPA air pollutant emissions factors (AP-42) for stationary combustion sources [26, 29]. Flaring activity for each basin is calculated as the ratio of NG flared to the total amount of NG sent to be flared, as reported in the GHGRP dataset [12]. Additional emission species (oxides of nitrogen [NO_X], carbon monoxide, lead, N_2O, particulate matter, sulfur dioxide [SO_2], total organic carbon [TOC], volatile organic compounds [VOCs], etc.) are calculated for fuel combustion based on EPA AP-42 EFs for flaring [29].

The emissions from NG flaring vary with NG composition, which itself varies by production basin and varies across the steps of the NG supply chain. NETL's NG life-cycle model calculates a unique combustion emissions profile, as discussed in the above paragraph, for each modeling iteration, so a deterministic table of NG flaring emissions is not available.

3.4.2 Natural Gas Combustion for Process Energy

This work models combustion of fuel in compressors and other equipment used throughout the NG supply chain, such as well drilling and completion equipment, workover equipment, dehydrators, generators, boilers, and process heaters. GHGRP comprises activity for three combustion categories [12]:

- Internal fuel combustion units that are not compressor-drivers with a rated heat capacity greater than 1 MMBtu/hr
- External fuel combustion units with a rated heat capacity greater than 5 MMBtu/hr
- Internal fuel combustion units of any heat capacity that are compressor drivers

Exhibit 3-20 through **Exhibit 3-22** represent the combustion activity for production, gathering and boosting, and distribution supply chain stages, respectively, based on GHGRP data [30]. This analysis uses EPA AP-42 EFs to calculate non-GHG emissions to air for the preceding three combustion categories. These EFs are shown in **Exhibit 3-23** [29].

Exhibit 3-20. Fuels combusted at NG production facilities

Techno-basin	p2.5/ mean/ p97.5	NG Combusted by Compressor Drivers (Mcf/facility-yr)	NG Combusted by External Combustion Equipment with Capacity of <1 MMBtu/hr (Mcf/facility-yr)	NG Combusted by External Combustion Equipment with Capacity of <5 MMBtu/hr (Mcf/facility-yr)	Diesel Combusted in Equipment with Capacity of <1 MMBtu/hr (gal/facility-yr)	Diesel Combusted in Equipment with Capacity of <5 MMBtu/hr (gal/facility-yr)
Appalachian – shale	p2.5	4.99E+05	2.08E+05	0.00E+00	0.00E+00	0.00E+00
	mean	1.16E+06	4.08E+05	2.67E+03	0.00E+00	1.41E+05
	p97.5	1.96E+06	6.41E+05	1.04E+04	0.00E+00	5.46E+05
Gulf – conv	p2.5	1.01E+06	2.34E+04	0.00E+00	0.00E+00	0.00E+00
	mean	2.32E+06	4.78E+04	0.00E+00	0.00E+00	0.00E+00
	p97.5	3.97E+06	7.16E+04	0.00E+00	0.00E+00	0.00E+00
Gulf – shale	p2.5	4.71E+05	9.13E+04	0.00E+00	0.00E+00	0.00E+00
	mean	9.36E+05	7.71E+05	2.96E+04	0.00E+00	8.25E-01
	p97.5	1.51E+06	1.66E+06	6.71E+04	0.00E+00	2.50E+00
Gulf – tight	p2.5	8.08E+05	3.21E+03	0.00E+00	0.00E+00	0.00E+00
	mean	1.35E+06	6.46E+04	0.00E+00	0.00E+00	0.00E+00
	p97.5	2.00E+06	1.41E+05	0.00E+00	0.00E+00	0.00E+00
Arkla – conv	p2.5	1.05E+05	0.00E+00	0.00E+00	0.00E+00	0.00E+00
	mean	6.24E+05	9.86E+03	0.00E+00	0.00E+00	0.00E+00
	p97.5	1.10E+06	2.34E+04	0.00E+00	0.00E+00	0.00E+00
Arkla – shale	p2.5	3.92E+04	2.47E+04	0.00E+00	0.00E+00	0.00E+00
	mean	9.11E+04	4.65E+04	0.00E+00	0.00E+00	0.00E+00
	p97.5	1.42E+05	6.76E+04	0.00E+00	0.00E+00	0.00E+00
Arkla – tight	p2.5	3.28E+05	2.94E+02	0.00E+00	0.00E+00	0.00E+00
	mean	1.42E+06	7.24E+03	2.36E+03	0.00E+00	0.00E+00
	p97.5	2.27E+06	2.16E+04	2.56E+04	0.00E+00	0.00E+00
East Texas – conv	p2.5	1.47E+04	2.67E+03	0.00E+00	0.00E+00	0.00E+00
	mean	4.15E+05	6.22E+03	0.00E+00	0.00E+00	0.00E+00
	p97.5	7.52E+05	9.04E+04	0.00E+00	0.00E+00	0.00E+00
East Texas – shale	p2.5	2.03E+04	0.00E+00	0.00E+00	0.00E+00	0.00E+00
	mean	2.03E+04	0.00E+00	0.00E+00	0.00E+00	0.00E+00
	p97.5	2.03E+04	0.00E+00	0.00E+00	0.00E+00	0.00E+00
East Texas – tight	p2.5	3.90E+05	4.83E+03	0.00E+00	0.00E+00	0.00E+00
	mean	7.22E+05	1.51E+05	0.00E+00	0.00E+00	0.00E+00
	p97.5	1.06E+06	3.21E+05	0.00E+00	0.00E+00	0.00E+00

Techno-basin	p2.5/ mean/ p97.5	NG Combusted by Compressor Drivers (Mcf/facility-yr)	NG Combusted by External Combustion Equipment with Capacity of <1 MMBtu/hr (Mcf/facility-yr)	NG Combusted by External Combustion Equipment with Capacity of <5 MMBtu/hr (Mcf/facility-yr)	Diesel Combusted in Equipment with Capacity of <1 MMBtu/hr (gal/facility-yr)	Diesel Combusted in Equipment with Capacity of <5 MMBtu/hr (gal/facility-yr)
Arkoma – conv	p2.5	1.34E+05	8.84E+03	0.00E+00	0.00E+00	0.00E+00
	mean	2.75E+05	2.08E+04	0.00E+00	0.00E+00	0.00E+00
	p97.5	3.38E+05	2.65E+04	0.00E+00	0.00E+00	0.00E+00
Arkoma – shale	p2.5	1.60E+05	0.00E+00	0.00E+00	0.00E+00	0.00E+00
	mean	2.63E+05	7.29E+02	4.62E+00	0.00E+00	0.00E+00
	p97.5	3.36E+05	1.41E+03	2.25E+01	0.00E+00	0.00E+00
South Oklahoma – shale	p2.5	3.03E+05	0.00E+00	0.00E+00	0.00E+00	0.00E+00
	mean	5.27E+05	2.84E+04	0.00E+00	0.00E+00	0.00E+00
	p97.5	7.05E+05	8.96E+04	0.00E+00	0.00E+00	0.00E+00
Anadarko – conv	p2.5	1.48E+06	0.00E+00	0.00E+00	0.00E+00	0.00E+00
	mean	3.16E+06	2.64E+03	0.00E+00	0.00E+00	0.00E+00
	p97.5	4.96E+06	9.61E+03	0.00E+00	0.00E+00	0.00E+00
Anadarko – shale	p2.5	9.17E+05	0.00E+00	0.00E+00	0.00E+00	0.00E+00
	mean	1.75E+06	1.46E+05	0.00E+00	0.00E+00	0.00E+00
	p97.5	2.46E+06	4.86E+05	0.00E+00	0.00E+00	0.00E+00
Anadarko – tight	p2.5	5.88E+05	0.00E+00	0.00E+00	0.00E+00	0.00E+00
	mean	1.02E+06	1.06E+04	0.00E+00	0.00E+00	0.00E+00
	p97.5	1.51E+06	3.75E+04	0.00E+00	0.00E+00	0.00E+00
Strawn – shale	p2.5	2.07E+06	0.00E+00	0.00E+00	0.00E+00	0.00E+00
	mean	2.89E+06	0.00E+00	0.00E+00	0.00E+00	0.00E+00
	p97.5	3.56E+06	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Fort Worth – shale	p2.5	1.35E+05	0.00E+00	0.00E+00	0.00E+00	0.00E+00
	mean	1.86E+06	0.00E+00	0.00E+00	0.00E+00	0.00E+00
	p97.5	2.19E+06	0.00E+00	0.00E+00	0.00E+00	0.00E+00
Permian – conv	p2.5	1.20E+06	3.05E+04	0.00E+00	0.00E+00	0.00E+00
	mean	1.70E+06	7.71E+04	2.46E+02	0.00E+00	0.00E+00
	p97.5	2.23E+06	1.34E+05	8.55E+02	0.00E+00	0.00E+00
Permian – shale	p2.5	1.50E+06	8.63E+04	0.00E+00	0.00E+00	0.00E+00
	mean	2.04E+06	3.04E+05	6.27E+02	0.00E+00	0.00E+00
	p97.5	2.55E+06	6.55E+05	4.86E+03	0.00E+00	0.00E+00
Green River – conv	p2.5	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
	mean	3.11E+02	0.00E+00	0.00E+00	0.00E+00	0.00E+00
	p97.5	7.40E+03	0.00E+00	0.00E+00	0.00E+00	0.00E+00

Techno-basin	p2.5/ mean/ p97.5	NG Combusted by Compressor Drivers (Mcf/facility-yr)	NG Combusted by External Combustion Equipment with Capacity of <1 MMBtu/hr (Mcf/facility-yr)	NG Combusted by External Combustion Equipment with Capacity of <5 MMBtu/hr (Mcf/facility-yr)	Diesel Combusted in Equipment with Capacity of <1 MMBtu/hr (gal/facility-yr)	Diesel Combusted in Equipment with Capacity of <5 MMBtu/hr (gal/facility-yr)
Green River – tight	p2.5	2.74E+04	0.00E+00	0.00E+00	0.00E+00	0.00E+00
	mean	8.95E+05	3.26E+04	1.06E+03	0.00E+00	0.00E+00
	p97.5	1.54E+06	6.93E+04	2.09E+03	0.00E+00	0.00E+00
Uinta – conv	p2.5	0.00E+00	2.35E+04	0.00E+00	0.00E+00	0.00E+00
	mean	0.00E+00	2.35E+04	0.00E+00	0.00E+00	0.00E+00
	p97.5	0.00E+00	2.35E+04	0.00E+00	0.00E+00	0.00E+00
Uinta – tight	p2.5	0.00E+00	0.00E+00	0.00E+00	0.00E+00	0.00E+00
	mean	5.33E+03	9.65E+03	0.00E+00	0.00E+00	0.00E+00
	p97.5	1.72E+04	4.11E+04	0.00E+00	0.00E+00	0.00E+00
San Juan – CBM	p2.5	1.53E+06	0.00E+00	0.00E+00	0.00E+00	0.00E+00
	mean	3.80E+06	2.47E+04	0.00E+00	0.00E+00	0.00E+00
	p97.5	5.24E+06	8.12E+04	0.00E+00	0.00E+00	0.00E+00
San Juan – shale	p2.5	1.33E+06	0.00E+00	0.00E+00	0.00E+00	3.09E+05
	mean	1.33E+06	0.00E+00	0.00E+00	0.00E+00	3.09E+05
	p97.5	1.33E+06	0.00E+00	0.00E+00	0.00E+00	3.09E+05
Piceance – tight	p2.5	2.00E+03	3.12E+04	0.00E+00	0.00E+00	0.00E+00
	mean	6.39E+03	5.07E+04	9.86E+03	0.00E+00	6.70E+02
	p97.5	1.55E+04	6.51E+04	1.77E+04	0.00E+00	1.20E+03

Exhibit 3-21. Fuels combusted at gathering facilities

Basin	p2.5/ mean/ p97.5	NG Combustion in External Fuel Combustion Units with a Rated Heat Capacity >5 MMBtu/hr (Mcf/facility-yr)	NG Combustion in Internal Fuel Combustion Units of any Heat Capacity that are Compressor-Drivers (Mcf/facility-yr)	NG Combustion in Internal Fuel Combustion Units that are not Compressor-Drivers, with a Rated Heat Capacity >1 MMBtu/hr (Mcf/facility-yr)
Appalachian	p2.5	1.64E+04	8.73E+06	1.01E+05
	mean	3.27E+04	1.20E+07	2.09E+05
	p97.5	5.31E+04	1.53E+07	3.59E+05
Gulf	p2.5	1.06E+05	2.38E+06	9.62E+04
	mean	1.98E+05	3.20E+06	4.54E+05
	p97.5	3.07E+05	4.08E+06	1.10E+06

Basin	p2.5/ mean/ p97.5	NG Combustion in External Fuel Combustion Units with a Rated Heat Capacity >5 MMBtu/hr (Mcf/facility-yr)	NG Combustion in Internal Fuel Combustion Units of any Heat Capacity that are Compressor-Drivers (Mcf/facility-yr)	NG Combustion in Internal Fuel Combustion Units that are not Compressor-Drivers, with a Rated Heat Capacity >1 MMBtu/hr (Mcf/facility-yr)
Arkla	p2.5	5.79E+04	3.91E+05	6.56E+01
	mean	5.01E+05	7.07E+05	3.53E+03
	p97.5	1.03E+06	1.06E+06	1.10E+04
East Texas	p2.5	5.74E+02	1.46E+06	0.00E+00
	mean	4.47E+04	2.96E+06	7.37E+03
	p97.5	9.09E+04	4.69E+06	2.21E+04
Arkoma	p2.5	0.00E+00	3.80E+06	2.61E+04
	mean	3.36E+04	8.34E+06	9.23E+04
	p97.5	9.60E+04	1.38E+07	1.74E+05
South Oklahoma	p2.5	0.00E+00	1.66E+06	0.00E+00
	mean	0.00E+00	2.61E+06	4.31E-01
	p97.5	0.00E+00	3.85E+06	1.30E+00
Anadarko	p2.5	7.44E+03	6.63E+06	5.31E+04
	mean	1.87E+04	8.68E+06	1.38E+05
	p97.5	3.59E+04	1.05E+07	2.41E+05
Strawn	p2.5	1.25E+04	1.53E+04	0.00E+00
	mean	5.12E+04	2.78E+06	6.49E+03
	p97.5	1.12E+05	4.03E+06	2.87E+04
Fort Worth	p2.5	0.00E+00	2.02E+06	0.00E+00
	mean	2.55E+04	3.46E+06	9.80E+03
	p97.5	1.01E+05	4.90E+06	3.70E+04
Permian	p2.5	8.07E+04	7.78E+06	1.41E+05
	mean	1.81E+05	1.02E+07	5.63E+05
	p97.5	3.03E+05	1.31E+07	1.14E+06
Green River	p2.5	1.50E+04	1.44E+06	2.58E+04
	mean	6.96E+04	3.22E+06	6.69E+04
	p97.5	1.41E+05	4.93E+06	1.07E+05
Uinta	p2.5	0.00E+00	1.17E+06	1.77E+04
	mean	0.00E+00	1.83E+06	6.99E+04
	p97.5	0.00E+00	2.35E+06	1.48E+05
San Juan	p2.5	0.00E+00	8.93E+06	7.72E+03
	mean	0.00E+00	1.37E+07	2.90E+04
	p97.5	0.00E+00	1.77E+07	5.41E+04

Basin	p2.5/ mean/ p97.5	NG Combustion in External Fuel Combustion Units with a Rated Heat Capacity >5 MMBtu/hr (Mcf/facility-yr)	NG Combustion in Internal Fuel Combustion Units of any Heat Capacity that are Compressor-Drivers (Mcf/facility-yr)	NG Combustion in Internal Fuel Combustion Units that are not Compressor-Drivers, with a Rated Heat Capacity >1 MMBtu/hr (Mcf/facility-yr)
Piceance	p2.5	2.03E+03	6.03E+05	3.00E+04
	mean	6.47E+03	1.84E+06	6.77E+04
	p97.5	1.22E+04	3.27E+06	1.07E+05

Exhibit 3-22. Combustion emissions from NG distribution equipment

Techno-basin	p2.5/ mean/ p97.5	NG Combustion in External Fuel Combustion Units with a Rated Heat Capacity >5 MMBtu/hr (tonnes CO_2/facility-yr)	NG Combustion in Internal Fuel Combustion Units of any Heat Capacity that are Compressor-Drivers (tonne CO_2/facility-yr)	NG Combustion in Internal Fuel Combustion Units that Are Not Compressor-Drivers, with a Rated Heat Capacity >1 MMBtu/hr (tonne CO_2/facility-yr)
National Average	p2.5	1.51E+03	2.14E+02	3.46E-01
	mean	2.36E+03	1.02E+03	1.68E+00
	p97.5	3.30E+03	2.09E+03	4.81E+00

Exhibit 3-23. NG combustion EFs

Emission Species	Internal Engine, Turbine (kg/scf)	Internal Engine, Reciprocating (kg/scf)	External Boiler, <10 million Btu/hr (kg/scf)
Carbon Dioxide	5.06E-02	5.38E-02	5.38E-02
Methane	3.95E-06	6.30E-04	1.03E-06
Nitrous Oxide	1.38E-06	0.00E+00	9.84E-07
Acenaphthene	8.07E-13	8.07E-13	8.07E-13
Acenaphthylene	8.07E-13	8.07E-13	8.07E-13
Acetaldehyde	1.84E-08	2.97E-06	0.00E+00
Acrolein	2.94E-09	2.43E-06	0.00E+00
Ammonia	0.00E+00	0.00E+00	1.44E-06
Anthracene	1.08E-12	1.08E-12	1.08E-12
Arsenic	8.97E-11	8.97E-11	8.97E-11
Barium	1.97E-09	1.97E-09	1.97E-09
Benzene	5.52E-09	9.42E-10	9.42E-10
Benz(a)anthracene	1.38E-09	8.07E-13	8.07E-13
Benzo(a)pyrene	5.38E-13	5.38E-13	5.38E-13
Benzo(b)fluoranthene	8.07E-13	8.07E-13	8.07E-13
Benzo(g,h,i)perylene	5.38E-13	5.38E-13	5.38E-13

Emission Species	Internal Engine, Turbine (kg/scf)	Internal Engine, Reciprocating (kg/scf)	External Boiler, <10 million Btu/hr (kg/scf)
Benzo(k)fluoranthene	8.07E-13	8.07E-13	8.07E-13
Beryllium	5.38E-12	5.38E-12	5.38E-12
1,3-Butadiene	1.98E-10	0.00E+00	0.00E+00
N-Butane	9.42E-07	9.42E-07	9.42E-07
Cadmium	3.19E-09	4.93E-10	4.93E-10
Carbon Monoxide	3.77E-05	1.79E-04	3.77E-05
Chromium	6.12E-09	6.28E-10	6.28E-10
Chrysene	8.07E-13	8.07E-13	8.07E-13
Cobalt	3.77E-11	3.77E-11	3.77E-11
Copper	3.18E-08	3.81E-10	3.81E-10
Dibenzo(a,h)anthracene	5.38E-13	5.38E-13	5.38E-13
Dichlorobenzene	5.38E-10	5.38E-10	5.38E-10
Dimethylbenz(a)anthracene	7.18E-12	7.18E-12	7.18E-12
Ethane	1.39E-06	1.39E-06	1.39E-06
Ethylbenzene	1.47E-08	0.00E+00	0.00E+00
Fluoranthene	5.52E-10	1.35E-12	1.35E-12
Fluorene	1.26E-12	1.26E-12	1.26E-12
Formaldehyde	3.26E-07	3.36E-08	3.36E-08
Indeno(1,2,3-cd)pyrene	8.07E-13	8.07E-13	8.07E-13
Isomers of Xylene	2.94E-08	1.01E-07	0.00E+00
Lead	2.24E-10	2.24E-10	2.24E-10
Manganese	3.69E-08	1.70E-10	1.70E-10
Mercury	3.05E-09	5.24E-09	1.17E-10
2-Methylnaphthalene	1.08E-11	1.08E-11	1.08E-11
3-Methylcholanthrene	8.07E-13	8.07E-13	8.07E-13
Molybdenum	4.93E-10	4.93E-10	4.93E-10
N-Hexane	8.07E-07	8.07E-07	8.07E-07
N-Pentane	1.17E-06	1.17E-06	1.17E-06
Naphthalene	5.98E-10	2.74E-10	2.74E-10
Nickel	5.29E-08	9.42E-10	9.42E-10
NO_X	1.47E-04	1.27E-03	4.49E-05
Phenanthrene	7.63E-12	7.63E-12	7.63E-12
Phenol	5.84E-09	0.00E+00	0.00E+00
Particulate Matter <2.5 microns	8.52E-07	4.49E-06	8.52E-07
Polycyclic Aromatic Hydrocarbon	1.01E-09	0.00E+00	0.00E+00
Propylene Oxide	1.33E-08	0.00E+00	0.00E+00

Emission Species	Internal Engine, Turbine (kg/scf)	Internal Engine, Reciprocating (kg/scf)	External Boiler, <10 million Btu/hr (kg/scf)
Propane	7.18E-07	7.18E-07	7.18E-07
Pyrene	2.24E-12	2.24E-12	2.24E-12
Selenium	1.08E-11	1.08E-11	1.08E-11
Sulfur Dioxide	2.69E-07	2.69E-07	2.69E-07
Toluene	5.98E-08	1.53E-09	1.53E-09
TOC	5.06E-06	0.00E+00	4.93E-06
Vanadium	1.03E-09	1.03E-09	1.03E-09
VOC	9.66E-07	5.20E-05	2.47E-06
Zinc	1.30E-08	1.30E-08	1.30E-08

For processing, transmission, and storage, an engineering approach is used to calculate the quantity of fuel combusted for compression. This approach calculates the compression energy from the GHGRP-reported horsepower and operating times for turbines (used by centrifugal compressors) and reciprocating engines (used by reciprocating compressors) [12]. The thermal efficiencies for turbines and reciprocating engines are used to equate compression energy with the heat content of the NG combusted by turbine and reciprocating engines. The thermal efficiencies and key EFs for turbines and reciprocating engines are shown in **Exhibit 3-24** [31, 32, 33, 34].

Exhibit 3-24. Parameters for turbines and reciprocating engines used as compressor drivers

Combustion Technology	Parameter	Unit	Value
Turbines	Thermal efficiency, HHV basis	dimensionless	26%
	CO_2 EF	kg CO_2/scf	0.0506
	CH_4 EF	kg CH_4/scf	3.95E-06
Reciprocating engines	Thermal efficiency, HHV basis	dimensionless	37.5%
	CO_2 EF	kg CO_2/scf	0.0538
	CH_4 EF	kg CH_4/scf	6.30E-04

3.5 Water Withdrawal

Shale gas and tight gas wells require stimulation by hydraulic fracturing prior to production. Stimulation water is the only type of water withdrawal accounted for in this analysis.

This analysis calculated stimulation water volumes from FracFocus, which is a hydraulic fracturing chemical registry managed by the Ground Water Protection Council and Interstate Oil and Gas Compact Commission [35]. The data are reported for individual wells and include fracture dates, locations, water input volume, and hydraulic fracturing fluid composition. There was no supporting information to distinguish between shale and tight wells; due to this data limitation, the stimulation volumes for shale gas and tight gas wells within a basin are modeled using the same value. Based on 2020 reporting year data, the stimulation volume parameters for the various basins are summarized in **Exhibit 3-25**.

Exhibit 3-25. Hydraulic fracturing stimulation water volumes by basin

Basin	Unit	p2.5	Mean	p97.5
Appalachian	gal/well	2.67E+05	1.51E+07	8.57E+07
Gulf Coast	gal/well	0.00E+00	1.31E+07	3.50E+07
Arkla	gal/well	0.00E+07	2.26E+07	4.58E+07
East Texas	gal/well	0.00E+00	2.57E+07	6.26E+07
Arkoma	gal/well	1.82E+04	1.65E+07	2.37E+07
South Oklahoma	gal/well	1.00E+06	1.85E+06	2.34E+06
Anadarko	gal/well	0.00E+00	1.21E+07	2.86E+07
Strawn	gal/well	4.85E+05	4.48E+06	1.10E+07
Fort Worth	gal/well	1.03E+04	4.46E+05	7.66E+06
Permian	gal/well	0.00E+00	1.72E+07	4.87E+07
Uinta	gal/well	3.56E+05	1.16E+07	2.54E+07
Green River	gal/well	1.64E+05	5.76E+05	1.51E+06
San Juan	gal/well	1.00E+06	1.85E+06	2.34E+06
Piceance	gal/well	1.59E+06	8.84E+06	2.43E+07

NG producers acquire water from fresh, brackish, or recycled sources. To develop parameters for water sourced for stimulation of shale gas and tight gas wells, this analysis uses data from EPA's report on the potential impacts of hydraulic fracturing on drinking water resources [36]. This analysis inventories the volume of water that comes from fresh (surface and underground) and other (brackish and recycled) water sources but does not account for the energy and emissions from the handling and transport of the water well sites. Past work by NETL showed that the energy use and air emissions from upstream water handling and transport are negligible in the context of the entire NG supply chain [2]; for simplicity, these energy requirements and emissions were not accounted for in this analysis. Due to unavailability of updated data sources, the shares of fresh and other water sources used for well stimulation remain unchanged from the 2019 NG baseline report [4]. These shares are shown in **Exhibit 3-26**.

Exhibit 3-26. Shares of water sources used for well stimulation

Basin	Fresh Water (Surface and Ground Water)	Other Water (Recycled and Brackish Water)
Appalachian	81.0%	19.0%
Gulf Coast	80.0%	20.0%
Arkla	100%	0%
East Texas	95.0%	5.0%

Arkoma	50.0%	50.0%
South Oklahoma	100%	0%
Anadarko	50.0%	50.0%
Strawn	92.0%	8.0%
Fort Worth	92.0%	8.0%
Permian	44.0%	56.0%
Green River	5.0%	95.0%
Uinta	5.0%	95.0%
San Juan	100%	0%
Piceance	5.0%	95.0%

3.6 Water Discharge From Wells

It is worth noting that due to unavailability of updated data sources, no revisions were made to this section as part of the report update. The data remain unchanged from the 2019 NG baseline report [4]. Water is discharged as produced water (which is produced during steady-state well operation and comes from water that naturally occurs in a formation) and flowback water (which is first injected during well stimulation and flows out of the well during completion).

3.6.1 Produced Water Discharge from Wells

For conventional wells, this analysis uses produced water data compiled by Argonne National Laboratory (ANL), which includes data on produced water volumes and water management practices in the oil and gas industry [37]. These data were collected from state and federal oil and gas agencies and represent 2007 operations. The data cover 31 states, 8 of which reported water-to-gas ratios and gas production data. For CBM wells, this analysis uses produced water data from the National Research Council, which provides data for the San Juan basin for the 2008 production year [38]. **Exhibit 3-27** shows the produced water rates for CBM and conventional NG wells.

Exhibit 3-27. Produced water volumes for CBM and conventional NG wells

Formation	Unit*	Parameter
CBM	bbl produced water/Mcf produced NG	0.038
	gal produced water/Mcf produced NG	1.6
Conventional	bbl produced water/Mcf produced NG	0.064
	gal produced water/Mcf produced NG	2.7

*Conversion factor: 1 bbl = 42 gal

To develop parameters for produced water from shale gas and tight gas wells, this analysis uses flow rates from EPA's report on the potential impacts of hydraulic fracturing on drinking water resources [36]. Geographically specific data were not available for produced water volumes, so one parameter was developed for all shale gas wells and another for all tight gas wells. The data were published in 2016 and represent long-term produced water rates. **Exhibit 3-28** shows the produced water rates for shale and tight NG wells.

Exhibit 3-28. Produced water volume for shale and tight gas wells

Formation	Unit	Minimum	Expected	Maximum
Shale gas	gal/day-well	0.83	820	12,000
Tight gas	gal/day-well	15	390	8,200

3.6.2 Flowback Water Discharge from Wells

This analysis calculates flowback water volumes for shale gas and tight gas wells as a percentage of hydraulic fracturing water input. EPA's report on the impacts of hydraulic fracturing on drinking water resources provides data on the volume of flowback water that exits the well as a percentage of average water use per well for various geographical regions [36]. The vintage of the source data ranges from 2009 to 2016. Most of these geographical regions align with the basins of this analysis. For instances in which data do not align geographically, this analysis uses average flowback rates, as provided by EPA.

Flowback water volumes are calculated as a percentage of the initial volume used to stimulate the well. Parameters describe the distribution of values and were developed for specific scenarios where data were available (specific to basin and formation) and defaulted to an average formation (shale or tight) value where specific data were unavailable. The key parameters for calculating flowback volume are summarized in **Exhibit 3-29** and represent the percentages of water inputs that return to the surface as flowback water.

Exhibit 3-29. Flowback water return rates

Basin – Formation	Minimum	Expected	Maximum
Average – shale	1%	33%	57%
Average – tight	0%	10%	60%
Appalachian – shale	7%	10%	22%
Arkla – shale	-	5%	-
Arkla – tight	-	5%	-
Arkoma – shale	1%	10%	57%
East Texas – shale	9%	20%	29%
Fort Worth – shale	9%	20%	29%
Permian – shale	6%	-	20%
Strawn – shale	6%	-	20%

3.7 Water Composition

It is worth noting that, due to unavailability of updated data sources, no revisions were made to this section as part of the report update. The data remain unchanged from the 2019 NG baseline report [4]. This analysis developed water emission parameters using the USGS

Produced Waters Geochemical Database [39]. The database holds locations, well types, and physical and chemical assays for over 100,000 water formations in the United States. This analysis stratified the data by basin and well type. The following decisions were applied to address data limitations:

- If less than 15 percent of the reported water formations had data for a specific emission species, the data were insufficient for the development of a parameter for the emission species and were excluded from the analysis.
- In instances where data were not available for a well type in a basin, different well types within the same basin were used as proxies. For example, shale gas data for the Gulf Coast were unavailable, so tight gas water quality data for the Gulf Coast were used as a proxy.
- The data do not consistently delineate flowback and produced water samples, so the same composition parameters are used for both produced water and flowback water.

3.8 WATER SPILL PROBABILITIES AND FATES

It is worth noting that, due to unavailability of updated data sources, no revisions were made to this section as part of the report update. The data remain unchanged from the 2019 NG baseline report [4]. To model releases of water to the environment, this analysis uses an EPA report on hydraulic fracturing spills [40]. EPA's report reviewed 457 hydraulic fracturing-related spills in 11 different states to characterize volumes spilled, volumes released to environmental receptors (soil or surface water), types of spilled materials, and sources of spills. There are multiple sources of spills, so this analysis reviewed the EPA data and determined that flowback water and produced water are the top two sources of spilled water from NG production. Compared to other sources of water, flowback water and produced water represent larger volumes of water with higher probabilities of release. This analysis applies the following decisions to address data limitations:

- The data for spill probabilities are representative of hydraulic fracturing activity but are applied to other well types. (In contrast, the *volume* of water that can be discharged, as discussed above, does vary among basins and well types).
- Due to data limitations on the exact pathways and fates of surface spills, subsurface migration of surface spills to groundwater are not considered.
- In instances where a spill goes to both environmental receptors (soil and surface water), the data do not provide the share of water that goes to each receptor. Due to this data limitation, the sum of environmental receptor probabilities is 1.08. The probabilities could be normalized to force their combined probability to exactly 1, but doing so would understate the emissions to each receptor. In this analysis, a slight overstatement of environmental receptor probability was chosen.

The probabilities used to calculate releases to the environment are summarized in **Exhibit 3-30**.

Exhibit 3-30. Spill probabilities for water from NG wells

Parameter	Probability
Probability that a spill occurs	0.01–0.1
Probability that a spill reaches an environmental receptor	0.65
Probability that an environmental receptor is soil	0.97
Probability that an environmental receptor is surface water	0.11

Additional parameters can be found in **Appendix B** (available in the release package published along with this report).

3.9 Wastewater Management

It is worth noting that, due to unavailability of updated data sources, no revisions were made to this section as part of the report update. The data remain unchanged from the 2019 NG baseline report [4], The data for regional wastewater management practices for the NG sector are sparse. This analysis uses three data sources to characterize wastewater management:

- Pennsylvania is the only state with sufficient data points to develop parameters for wastewater disposal [41, 42]; these data are used to represent water management for gas produced from the Appalachian basin.
- A USGS factsheet on water produced from CBM is used to characterize the wastewater management for CBM produced in the San Juan basin [43].
- The wastewater management parameters for the remaining scenarios were developed from ANL's produced water report [37]. The ANL produced water report data were organized by state activity, so this analysis mapped the state data into NG production basins. For basins in one state, the state data were used to represent the entire basin; for basins that span multiple states, the data for the multiple states were averaged to account for each basin.

If water does not have high levels of TDS or other pollutants, it can be conveyed to a municipal wastewater treatment facility, treated via the facility's process, and discharged to surface waters. A typical municipal wastewater treatment process requires approximately 449 kWh per million liters per day of wastewater that is treated (conservative estimate) [44]. Municipal wastewater treatment is partially effective at treating flowback water pollutants and provides zero benefit in terms of reduction of mass loadings for ionic constituents, including salts and other dissolved solids. Crystallization is necessary when flowback water contains pollutants in concentrations that are too high to be treated by municipal wastewater treatment. Crystallization evaporates wastewater, leaving residual solids behind. The residual solids can then be disposed of in a landfill or other facility, pursuant to local regulations and requirements. A crystallizer unit sufficient to treat flowback water volumes has a typical energy requirement of approximately 54 kWh per 1,000 liters of water treated [45]. When converting to a mass basis, this electricity requirement is 0.054 kWh per kg water.

Disposal in a deep injection well is another option for water management. Injection wells allow placement of water in an underground formation such as sandstone or limestone. This analysis quantifies the energy use and emissions associated with water injection by applying engineering calculations that are a function of injection well depth, well diameter, and formation pressure [46].

Additional parameters can be found in **Appendix B** (available in the release package published along with this report).

3.10 LAND USE CHANGE EMISSIONS

The development of land for NG production and gathering and boosting incurs direct land use changes. For instances in which these changes displace agriculture, indirect land use changes also occur.

3.10.1 Direct Land Use Change

It is worth noting that, due to unavailability of updated data sources, no revisions were made to this section as part of the report update. The data and methodology remain unchanged from the 2019 NG baseline report [4]. This analysis evaluates GHG emissions from land use change based on EPA's method for the quantification of GHG emissions, in support of the Renewable Fuel Standards [47]. EPA's method quantifies GHG emissions that are expected to result from land use changes from forest, grassland, savanna, shrubland, wetland, perennial, or mixed land use types to agricultural, cropland, grassland, savanna, or perennial land use types. Relying on an evaluation of historic land use change completed by Winrock International, EPA calculated a series of GHG EFs for the following criteria: change in biomass carbon stocks, lost forest sequestration, annual soil carbon flux, CH_4 emissions, NO_X emissions, annual peat emissions, and fire emissions [48]. These criteria would result from land conversion over a range of timeframes. EPA's analysis also includes calculated reversion factors for the reversion of land use from agricultural cropland, grassland, savanna, and perennial to forest, grassland, savanna, shrub, wetland, perennial, or mixed land uses. Emission factors considered for reversion were change in biomass carbon stocks, change in soil carbon stocks, and annual soil carbon uptake over a variety of timeframes. Each of these EFs for land conversion and reversion was included, for a total of 756 global countries and regions within countries, including the 48 contiguous states.

The 14 onshore basins in this analysis have unique profiles of land types (grassland and forest). **Exhibit 3-31** shows the direct CO_2 EFs from land use change for each basin of this analysis. The factors differ between permanent (no reversion) and temporary (reversion) land use change. This analysis models all well pads and gathering and boosting stations as permanently converted sites; it models gathering and boosting pipelines as temporary land use change.

Exhibit 3-31. Land use change EFs for NG basins

Basin	No Reversion	Reversion		
	Grassland (kg CO_2/m^2)	Forest (kg CO_2/m^2)	Grassland (kg CO_2/m^2)	Forest (kg CO_2/m^2)
Anadarko	2.82	28.3	-3.00	-4.26
Appalachian	4.63	56.7	-3.38	23.33
Arkla	2.58	38.2	-2.80	6.05
Arkoma	2.49	42.3	-2.72	10.39
East Texas	2.26	26.3	-2.53	-5.18
Fort Worth	2.26	26.3	-2.53	-5.18
Green River	1.77	35.3	-2.11	4.67
Gulf Coast	2.42	32.3	3.54	-15.67
Permian	2.26	26.3	-2.53	-5.18
Piceance	1.92	30.8	-2.24	-0.14
San Juan	1.28	22.0	-1.69	-4.73
South Oklahoma	2.82	28.3	-3.00	-4.26
Strawn	2.26	26.3	-2.53	-5.18
Uinta	2.06	23.2	-2.36	-5.41

3.10.2 Indirect Land Use Change

The land use method used in this analysis does not calculate direct land use change emissions for agricultural conversion, but it does calculate a net change from indirect effects (i.e., displacement of agricultural land to another region). The EF for displaced agricultural land is 24.6 kg CO_2/m^2 of displaced agriculture [49]. This is the only EF used by the indirect land use calculations because the exact location of replaced agricultural land is unknown.

The shares of land types of each basin were developed from Organization for Economic Co-operation and Development data on land cover for the latest available reporting year (i.e., 2019) [50]. The data are provided on a state level; this analysis transformed the state data to basin level using state-to-basin mapping. Three land types are profiled: forest, grassland, and cropland. **Exhibit 3-32** shows the land use profile for each basin in this analysis.

Exhibit 3-32. Land use types for NG basins

Basin	Fraction of Land Use		
	Grassland	Forest	Agriculture
Anadarko	0.559	0.190	0.252
Appalachian	0.074	0.724	0.202
Arkla	0.098	0.676	0.226
Arkoma	0.189	0.537	0.274
East Texas	0.290	0.477	0.233
Fort Worth	0.290	0.477	0.233

Basin	Fraction of Land Use		
	Grassland	Forest	Agriculture
Green River	0.229	0.688	0.082
Gulf Coast	0.194	0.576	0.230
Permian	0.290	0.477	0.233
Piceance	0.326	0.515	0.159
San Juan	0.253	0.719	0.029
South Oklahoma	0.559	0.190	0.252
Strawn	0.290	0.477	0.233
Uinta	0.065	0.894	0.041

3.11 Land Use Area

The development of new NG wells incurs land use change at production sites and induces the expansion of gathering and boosting networks. This analysis characterizes land use change for both the production and the gathering and boosting stages. Other supply chain stages (processing through distribution) are crucial to the handling and delivery of NG but are assumed to largely comprise existing facilities and pipelines that do not incur land use change burdens within the temporal boundaries of this analysis. As part of future modeling updates, the land use burdens associated with new transmission pipelines will be evaluated.

3.11.1 Land Use Area (Production)

The land area for NG well pads ranges 1,000–20,200 m^2 per well pad. CBM wells are on the low end of this range. Shale gas and tight gas wells are on the high end of this range, except for shale gas wells in the Appalachian basin. The low land use intensity in the Appalachian basin is due to new technologies that minimize the land use intensity of shale wells [51]. NG production sites are permanently converted to an industrial land application. **Exhibit 3-33** shows land use areas for NG production sites, specified by production technologies and basins. It is worth noting that, due to unavailability of updated data sources, no revisions were made to the land use areas as part of the report update. The data remain unchanged from the 2019 NG baseline report [4]. Recent work by Dai et al. [52] was not incorporated into this analysis as the Dai et al. study was released during the final phases of report preparation.

Exhibit 3-33. Land use area for NG production sites

Basin	Technology	m^2/Well Pad
Anadarko	Conv	10,100
	Shale	20,200
	Tight	20,200
Appalachian	Shale	6,000
Arkla	Conv	10,100
	Shale	20,200
	Tight	20,200

Basin	Technology	m^2/Well Pad
Arkoma	Conv	10,100
	Shale	20,200
East Texas	Conv	10,100
	Shale	20,200
	Tight	20,200
Fort Worth	Shale	20,200
Green River	Conv	10,100
	Tight	20,200
Gulf Coast	Conv	10,100
	Shale	20,200
	Tight	20,200
Permian	Conv	10,100
	Shale	20,200
Piceance	Tight	20,200
San Juan	Conv	10,100
	CBM	1,000
South Oklahoma	Shale	20,200
Strawn	Shale	20,200
Uinta	Conv	10,100
	Tight	20,200

Shale gas and tight gas wells usually have multiple wells at one well pad, ranging 1–16 wells with an expected value of 5 [53]. Conventional and CBM wells were considered to have only one well per well pad, as these wells are drilled vertically, which does not allow for multiple wells at one well pad.

GHGRP data were used to estimate the number of new wells producing NG in 2020 for each scenario [12]. Data for wells completed in 2020 were taken to develop NG production and EUR estimates. A crosswalk was then created between GHGRP and Enverus data [15, 12]. All scenarios had new production site installations in 2020 except all conventional scenarios, Arkla tight, Fort Worth shale, Strawn shale, San Juan shale, and San Juan CBM. Uncertainty ranges were prescribed for the number of wells drilled at a well pad, as multiple wells at one well pad will share the land use burdens of a production site. GHGRP was also used to estimate the 2020 production share for new NG wells in each basin [12]. These production shares are consistent with the temporal boundaries discussed in **Section 2.5** and are necessary to apportion land use burdens from new wells to total NG produced in a basin. **Exhibit 3-34** shows the land areas by region and well type, apportioned to total NG produced in each basin.

Exhibit 3-34. Land areas per unit of NG produced

Basin	Technology	New Well Land Area (m^2/kg NG)	Percentage of Total 2020 Production from New Wells Completed in 2020	Normalized Area (m^2/kg NG)
Anadarko	Conv	-	-	-
	Shale	2.72E-05	0.56%	1.51E-07
	Tight	1.80E-05	0.63%	1.14E-07
Appalachian	Shale	2.68E-06	4.49%	1.21E-07
Arkla	Conv	-	-	-
	Shale	8.67E-06	6.92%	5.99E-07
	Tight	-	-	-
Arkoma	Conv	-	-	-
	Shale	1.50E-05	1.38%	2.07E-07
East Texas	Conv	-	-	-
	Shale	8.17E-06	2.40%	1.96E-07
	Tight	1.74E-05	0.28%	4.82E-08
Fort Worth	Shale	-	-	-
Green River	Conv	-	-	-
	Tight	5.61E-05	0.60%	3.39E-07
Gulf Coast	Conv	-	-	-
	Shale	6.42E-05	1.97%	1.27E-06
	Tight	3.34E-05	5.85%	1.95E-06
Permian	Conv	-	-	-
	Shale	2.94E-05	1.80%	5.30E-07
Piceance	Tight	9.33E-05	0.79%	7.36E-07
San Juan	Shale	-	-	-
	CBM	-	-	-
South Oklahoma	Shale	1.74E-05	4.13%	7.21E-07
Strawn	Shale	-	-	-
Uinta	Conv	-	-	-
	Tight	2.56E-05	0.36%	9.14E-08

3.11.2 Land Use Area (Gathering and Boosting)

It is worth noting that, due to unavailability of updated data sources, no revisions were made to this section as part of the report update. The data and methodology remain unchanged from the 2019 NG baseline report [4]. The land used by gathering and boosting systems was calculated using data from Jordaan et al., who calculated the spatial footprint of various stages of NG systems in Barnett Shale [54]. They used satellite imagery to determine the area associated with production sites, gathering pipelines, gathering sites, processing sites, transmission sites, disposal, and power plants. The total area of gathering sites in the Barnett Shale area is approximately 472,000 m^2 [54]. The total pipeline length of gathering pipelines in the area studied is approximately 2,590,000 meters (m). This analysis factors the above pipeline data by a 15.2 m (50 feet [ft]) right-of-way to arrive at a pipeline area of 39,500,500 m^2. Barnett Shale has achieved mature production levels, so the area occupied by gathering and boosting is not expected to change. To obtain a land change parameter normalized over the lifetime of production, the land change areas for pipeline and gathering sites were divided by the total economically recoverable EUR for Barnett Shale. The economically recoverable EUR of Barnett Shale is 46.5 Tcf [55]. For this analysis, Browning et al.'s EUR is used only in the calculation of gathering and boosting land use intensity because it matches the geographical boundaries of Jordaan et al.'s land area assessment. Dividing the land use area for gathering and boosting systems for Barnett Shale by the EUR for Barnett Shale gives land use change factors of 5.37E-07 m^2/kg NG and 4.49E-05 m^2/kg NG for gathering and boosting stations and gathering pipelines, respectively. The land used by gathering and boosting facilities is permanently converted with no restoration of vegetation. The land used by gathering pipelines is temporarily converted during pipeline installation and reverts to its original land type (forest or grassland) within five years.

Data for gathering and boosting land use are not available for other production regions. This analysis uses the above land use intensity factors as a proxy for the gathering and boosting land use intensities in other basins. (The same land use intensity is used for gathering and boosting across all basins, but as discussed in **Sections 3.10.1** and **3.10.2**, the land type profiles vary across basins.)

4 Modeling Approach

This analysis uses NETL's NG life cycle model to calculate energy and material flows. The development of this model required the development of unit processes, connections between supply chain stages, and choices about apportioning environmental burdens between co-products.

4.1 Unit Processes

NETL's NG life cycle model is a network of unit processes. A unit process accounts for the energy (purchased fuels and electricity) and materials (raw materials and intermediate products) at one point within a supply chain. The unit processes used in this analysis account for GHGs (and other emissions) from venting, fugitive, and combustion emission sources. Every unit process must calculate a numerator (emissions) and a denominator (a reference flow).

Unit process numerator: Most unit processes calculate emissions as the product of an EF and an AF. For example, the emissions from high-bleed pneumatic controllers are the product of an EF (in units of scf NG/device-hr) and corresponding AFs (count of devices and hours of operation). In many instances, the unit process also needs to apply the composition of the emitted NG to convert the bulk flow (NG) to specific emissions (CH_4 and CO_2).

Unit process denominator: Most unit processes use a reference flow of 1 kg of NG output. The emissions (i.e., the numerator of the unit process) are divided by the output of NG to arrive at emissions per unit of NG throughput. It is important for the denominator to represent the same boundaries as the numerator (especially spatial and temporal boundaries) because mismatched parameters will lead to erroneous emission rates.

Exhibit 4-1 through **Exhibit 4-7** list the unit processes for each supply chain stage, where **Exhibit 4-4**, **Exhibit 4-5**, and **Exhibit 4-6** represent the three substages of transmission. These exhibits also show the key data sources used to calculate the emissions for each unit process.

Exhibit 4-1. Unit processes and data sources used for NG production

ID	Unit Processes	EPA GHGRP [12]	EPA GHGI [19]	EPA [31, 32]	API [26]	API/ANGA [25]	Allen et al. [24]	FracFocus [35]	ANL [37]	USGS [16]	EPA [40]	PA DEP [41, 42]	EPA [47]	USDA [56]
1	Well construction		•											
2	Water disposal/ flowback water										•			
3	Water disposal/ produced water								•					
4	Water disposal/injection											•		
5	Water disposal/ wastewater treatment											•		
6	Water emissions/to water									•	•			

ID	Unit Processes	EPA GHGRP [12]	EPA GHGI [19]	EPA [31, 32]	API [26]	API/ANGA [25]	Allen et al. [24]	FracFocus [35]	ANL [37]	USGS [16]	EPA [40]	PA DEP [41, 42]	EPA [47]	USDA [56]
7	Water emissions/to soil									•	•			
8	Land use change/ direct/no reversion												•	•
9	Land use change/indirect												•	•
10	Hydraulic fracturing/ completions/no flaring	•												
11	Hydraulic fracturing/ completions/flaring	•												
12	Hydraulic fracturing/ workovers/no flaring	•												
13	Hydraulic fracturing/ workovers/flaring	•												
14	Conventional completion/ no flaring	•												
15	Conventional completion/flaring	•												
16	Conventional workover/ no flaring	•												
17	Conventional workover/flaring	•												
18	Pneumatic device/high bleed	•												
19	Pneumatic device/ intermittent bleed	•												
20	Pneumatic device/low bleed	•												
21	Pneumatic device/pumps	•												
22	Equipment leaks/connectors	•												
23	Equipment leaks/flanges	•												
24	Equipment leaks/ open ended lines	•												
25	Equipment leaks/other	•												
26	Equipment leaks/ pressure relief valves	•												
27	Equipment leaks/pumps	•												
28	Equipment leaks/valves	•												
29	Dehydrators/small glycol	•												
30	Dehydrators/desiccant	•												
31	Dehydrators/large glycol	•												
32	Acid gas removal	•												
33	Flare stacks	•												

ID	Unit Processes	EPA GHGRP [12]	EPA GHGI [19]	EPA [31, 32]	API [26]	API/ANGA [25]	Allen et al. [24]	FracFocus [35]	ANL [37]	USGS [16]	EPA [40]	PA DEP [41, 42]	EPA [47]	USDA [56]
34	Combustion (NG) for compressor drivers	•												
35	Combustion (NG) <1 MMBtu/hr	•												
36	Combustion (NG) <5 MMBtu/hr	•												
37	Combustion (diesel) <1 MMBtu/hr	•												
38	Reciprocating compressor venting	•												
39	Compressor blowdowns		•											
40	PRV upset		•											
41	Produced water tank venting				•		•							
42	Production vessel blowdowns		•											
43	Liquids unloading	•				•	•							

PA DEP = Pennsylvania Department of Environmental Protection; USDA = U.S. Department of Agriculture

Exhibit 4-2. Unit processes and data sources used for NG gathering and boosting

ID	Unit Process	EPA GHGRP [12]	EPA GHGI [19]	EPA AP-42 [29]	API [26]	Jordaan et al. [54]	EPA [47]	USDA [56]	GSI [57]	Zimmerle et al. [58]
44	Gathering and boosting construction					•				
45	Land use change/direct/reversion					•	•	•		
46	Land use change/indirect					•	•	•		
47	Pneumatic device/high bleed	•							•	
48	Pneumatic device/intermittent bleed	•							•	
49	Pneumatic device/low bleed	•							•	
50	Pneumatic device/pumps	•							•	
51	Gas service/connectors	•								•
52	Gas service/flanges	•								
53	Gas service/open-ended lines	•								
54	Gas service/pressure relief valves	•								•
55	Gas service/valves	•								•
56	Gathering pipelines/cast iron gathering pipeline	•								
57	Gathering pipelines/plastic/composite gathering pipeline	•								

ID	Unit Process	EPA GHGRP [12]	EPA GHGI [19]	EPA AP-42 [29]	API [26]	Jordaan et al. [54]	EPA [47]	USDA [56]	GSI [57]	Zimmerle et al. [58]
58	Gathering pipelines/protected steel gathering pipeline	•								
59	Gathering pipelines/unprotected steel gathering pipeline	•								
60	Dehydrators/small glycol	•								
61	Dehydrators/desiccant	•								
62	Dehydrators/large glycol	•								
63	Acid gas removal	•								•
64	Flaring	•								
65	Combustion/external fuel combustion units with a rated heat capacity >5 MMBtu/hr	•								
66	Combustion/internal fuel combustion units of any heat capacity that are compressor-drivers	•								
67	Combustion/internal fuel combustion units that are not compressor-drivers, with a rated heat capacity >1 MMBtu/hr	•								
68	Reciprocating compressor venting	•								•
69	Blowdowns/all other	•								
70	Blowdowns/compressors	•								
71	Blowdowns/emergency shutdowns	•								
72	Blowdowns/facility piping	•								
73	Blowdowns/pig launching and receiving	•								
74	Blowdowns/pipeline venting	•								
75	Blowdowns/scrubbers and strainers	•								
76	Mishaps		•							

Exhibit 4-3. Unit processes and data sources used for NG processing

ID	Unit Process	EPA GHGRP [12]	EPA GHGI [19]	EPA AP-42 [29]
77	Acid gas removal	•		
78	Dehydrators/desiccant	•		
79	Dehydrators/large glycol	•		
80	Blowdowns/all other equipment with a physical volume greater than or equal 50 cubic feet	•		
81	Blowdowns/compressors	•		
82	Blowdowns/emergency shutdowns	•		

ID	Unit Process	EPA GHGRP [12]	EPA GHGI [19]	EPA AP-42 [29]
83	Blowdowns/facility piping	•		
84	Blowdowns/pig launching and receiving	•		
85	Blowdowns/scrubbers and strainers	•		
86	Flaring	•		
87	Centrifugal compressor venting	•		
88	Reciprocating compressor venting	•		
89	Equipment leaks	•		
90	Combustion exhaust (compressor turbines and engines)	•		•
91	Processing pneumatics		•	

Exhibit 4-4. Unit processes and data sources used for NG transmission stations

ID	Unit Process	EPA GHGRP [12]	EPA GHGI [19]	EPA AP-42 [29]	Zimmerle et al. [59]
92	Pneumatic device/high bleed	•			
93	Pneumatic device/intermittent bleed	•			
94	Pneumatic device/low bleed	•			
95	Blowdowns/other	•			
96	Blowdowns/compressors	•			
97	Blowdowns/emergency shutdowns	•			
98	Blowdowns/facility piping	•			
99	Blowdowns/pig launching and receiving	•			
100	Blowdowns/pipeline venting	•			
101	Blowdowns/scrubbers and strainers	•			
102	Dehydrator venting		•		
103	Centrifugal compressor venting	•			•
104	Combustion exhaust for turbine-driven centrifugal compressors	•		•	
105	Reciprocating compressor venting	•			•
106	Reciprocating engine combustion exhaust	•		•	
107	Equipment leaks	•			
108	Flare stacks	•			

Exhibit 4-5. Unit processes and data sources used for NG storage

ID	Unit Process	EPA GHGRP [12]	EPA GHGI [19]	EPA AP-42 [29]
109	Pneumatic device/high bleed	•		
110	Pneumatic device/intermittent bleed	•		
111	Pneumatic device/low bleed	•		
112	Centrifugal compressor venting	•		
113	Combustion exhaust for turbine-driven centrifugal compressors	•		•
114	Reciprocating compressor venting	•		
115	Reciprocating engine combustion exhaust	•		•
116	Equipment leaks/storage station	•		
117	Equipment leaks/storage wellhead	•		
118	Dehydrator venting		•	
119	Station venting		•	

Exhibit 4-6. Unit processes and data sources used for NG transmission pipelines

ID	Unit Process	EPA GHGRP [12]	EPA GHGI [19]
120	All other pipeline segments with a physical volume greater than or equal to 50 cubic feet	•	
121	Emergency shutdowns including pipeline incidents	•	
122	Equipment replacement or repair (e.g., valves)	•	
123	New construction or modification of pipelines including commissioning and change of service	•	
124	Operational precaution during activities (e.g., excavation near pipelines)	•	
125	Pipeline integrity work (e.g., the preparation work of modifying facilities, ongoing assessments, maintenance, or mitigation)	•	
126	Traditional operations or pipeline maintenance	•	
127	Pipeline fugitives		•

Exhibit 4-7. Unit processes and data sources used for NG distribution

ID	Unit Process	EPA GHGRP [12]	EPA GHGI [19]	EPA AP-42 [29]	Moore et al. [60]	Littlefield et al. [4]
128	T-D transfer station	•				
129	Above-grade metering-regulating stations that are not above-grade T-D transfer stations	•				
130	Below-grade T-D station	•				
131	Distribution mains & services	•				
132	External fuel combustion units with a rated heat capacity >5 MMBtu/hr	•				
133	Internal fuel combustion units of any heat capacity that are compressor-drivers	•				
134	Internal fuel combustion units that are not compressor-drivers, with a rated heat capacity >1 MMBtu/hr	•				
135	Customer meters/residential		•			
136	Customer meters/commercial and industrial		•		•	•
137	PRV releases		•			
138	Pipeline blowdowns		•			
139	Mishaps/dig ins		•			

Each unit process falls into one of six categories, which are further described below:

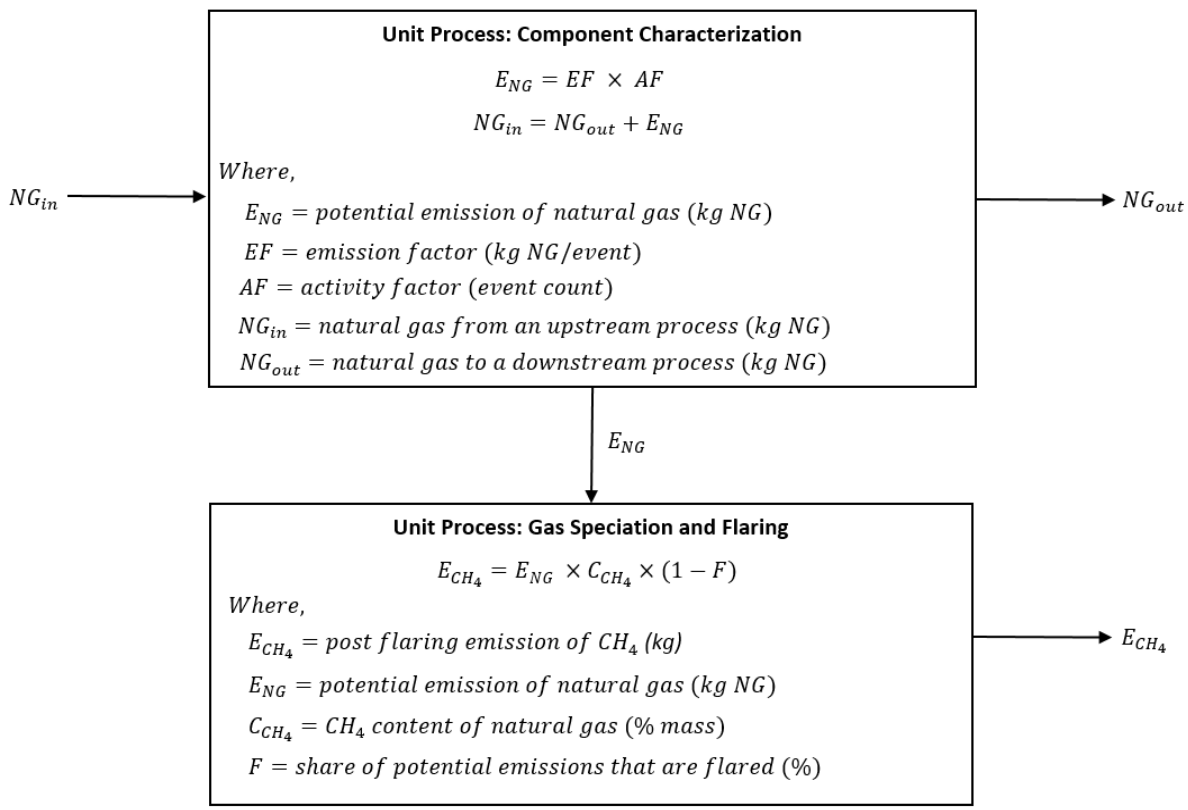
- Venting (with flaring when applicable)
- Fugitives
- NG combustion for process energy
- Land use
- Water
- Ancillary processes

4.1.1 Venting

Venting is the intentional release of emissions to air and occurs in all stages of the NG supply chain. Examples of venting include the occasional blow downs of compressors or other equipment during maintenance activities, the operation of pneumatic devices that use NG to actuate control equipment, or liquids-unloading events that remove wellbore liquids that impede NG production.

In instances where vapor recovery is feasible, gas is captured for sale or use as fuel; otherwise, vented streams can be sent to flares and combusted. Flares convert CH_4 and VOCs in NG to CO_2, which is environmentally preferable because it reduces the potential environmental impacts of the emissions. Flaring is feasible in instances where there are large or continuous vent streams, such as the potential emissions from a well completion event when large volumes of flowback water are handled or a large NG processing facility that is continuously refining product streams. Flaring is usually not feasible for episodic venting (i.e., occasional, sporadic venting) or when the vented flow rate is not sufficient to sustain flaring. For example, the emissions from pneumatic devices and liquids unloading are intermittent and spatially scattered, which makes flaring unfeasible. **Exhibit 4-8** depicts the unit process math for venting.

Exhibit 4-8. Unit process math for venting and flaring of potential emissions



As depicted in **Exhibit 4-8**, the estimation of venting (and flaring) emissions first requires the computation of the potential emission of "whole gas." Whole gas represents the complete chemical profile of NG (CH_4, CO_2, other hydrocarbons, H_2S, and inert gases such as helium or argon). In instances where an EF is in terms of CH_4 only, it is necessary to divide it by the CH_4 content in the whole gas to convert it to a quantity of whole gas. The whole gas is then factored by the flaring activity (the share of events that are controlled with flaring). Gas that is not flared is emitted as individual chemical species using the same chemical profile as the whole gas. When gas is flared, CH_4 and other hydrocarbons are converted to CO_2; H_2S is converted to SO_2; and inert gases pass through the flare. Flares are modeled with a combustion effectiveness of 98 percent [28], so 2 percent of the emissions from flare stacks represent whole gas that slips through flares without being combusted.

4.1.2 Fugitives

Fugitives are unintentional emissions from equipment malfunctions (e.g., stuck dump valves) or infrastructure that is not performing as designed (e.g., leaks from connectors, valve stems, or pipelines). Fugitive emissions are the only emission source from the NG supply chain that can be correctly referred to as leaks.

Fugitive emissions occur in all supply chain stages. Production has fugitive emissions from connectors, flanges, open-ended lines, pressure relief valves, pumps, and valves. In addition to these specific emission sources, the GHGRP data also have a fugitive emission category for "other" fugitives [12]. Gathering and boosting has fugitive emissions from equipment leaks and pipelines. Processing has fugitive emissions from equipment leaks. Transmission and storage has fugitive emissions from equipment leaks and pipeline leaks. Distribution has fugitive emissions from transmission and distribution stations, metering and regulating stations, mains and services, and customer meters.

The computation of fugitive emissions is similar to the computation of venting emissions (discussed in **Section 4.1.1**), but in no instance is flaring applied for fugitive emissions. First, whole gas emissions are calculated as the product of AFs and EFs (converting CH_4 to whole gas if necessary). Then, the whole gas emissions are speciated into individual components based on the chemical profile of the whole gas.

4.1.3 Natural Gas Combustion for Process Energy

The NG supply chain consumes a portion of product NG to fuel the engines, turbines, and other equipment that are used to move and process NG. There are three categories of equipment that consume NG for process energy: reciprocating engines, gas turbines, and external combustion units.

Reciprocating engines and gas turbines are used as prime movers for reciprocating compressors and centrifugal compressors, respectively. The fuel consumed by reciprocating engines and gas turbines is a function of their thermal efficiencies, factored by the compression efficiencies of their associated compressors. Thermal efficiency represents the efficiency at which input fuel energy is converted to output work of the engine or turbine. The compression of a gas requires work (specifically, the movement of a piston or impeller to displace gas). Compression efficiency represents the efficiency at which compressor input energy performs work on a gas. By equating gas compression with the combined efficiencies of prime movers and compressors, the corresponding fuel requirements and fuel combustion emissions can be determined.

Reciprocating engines and gas turbines have different fuel combustion characteristics. Both types of prime movers emit uncombusted hydrocarbons, including CH_4, in their exhaust gas, but reciprocating engines also emit CH_4 through piston rod packing. For reciprocating compressors, the NO_X EF is highly variable and depends on engine type (2-stroke lean-burn, 4-stroke lean-burn, and 4-stroke rich-burn) [32]. The NO_X EFs for gas turbine compressors are also variable, but of lower magnitude than those for reciprocating compressors [31].

External combustion units are used to provide process heat. Heat is necessary to regenerate solvents used by dehydrators and AGR units. Dehydration is necessary throughout the supply chain, and usually employs glycol-based solvents that remove water from the NG product stream. AGR is employed in both the gathering and boosting and the processing stages and is used to remove CO_2 and H_2S, when applicable. The removal of water and acid gases improves the heating value of NG and prevents fouling of NG infrastructure and end-use equipment.

4.1.4 Water

Water consumption accounts for the net volume of water withdrawal and discharge. Water discharges from wells can result from the flowback of water used for hydraulic fracturing as well as produced water that is naturally present in NG formations. The flowback and produced water from NG production sites is sent to injection wells for disposal, to treatment facilities, or for enhanced recovery (of oil or unspecified well products).

Water emissions account for the chemical, mineral, and quality characteristics of discharged water. Water emissions are a function of the volume, composition, and spill probability and fate of discharged water.

This analysis accounts for water consumption and water emissions for the production stage only. The production of NG uses water for well stimulation and manages flows of flowback and produced water, but subsequent stages of the "production through distribution" supply chain do not rely on significant volumes of water.

4.1.5 Land Use

Land use accounts for the area of land occupied by new infrastructure. The conversion of land from its natural state to industrial use changes the long-term carbon balance of the land, which results in GHG emissions. The land use metrics used for this analysis quantify the land area that is transformed from its original state for the installation of NG infrastructure. The transformation of land causes the direct emission of GHG emissions due to changes in above-ground biomass and soil carbon. The conversion of agricultural land causes indirect GHG emissions because new agricultural land must be developed to replace the displaced agricultural land.

This analysis accounts for land use change that is only for NG production sites and gathering and boosting infrastructure. An NG production site has a well pad that holds permanent equipment and provides room for development and maintenance activities. Gathering and boosting systems comprise gas treatment and compression facilities as well as pipelines. The drilling and completion of new wells and the expansion of gathering and development of new plays incurs land use change. The infrastructure for other stages of the supply chain is largely representative of legacy processing facilities, transmission networks, and local distribution companies that are not currently incurring land use change.

4.1.6 Ancillary Processes

Ancillary processes account for indirect contributors to the NG supply chain. These processes have cradle-to-gate burdens aggregated into a single, black box process. The ancillary processes comprise electricity, diesel (used to power engines used during well construction), and steel and concrete (used as materials for the construction of wells, production facilities, gathering pipelines, and gathering and boosting facilities). **Exhibit 4-9** summarizes 2020 data year results from EIA's Form-923 [61], which represents the mix of electricity generation technologies used for the 2020 U.S. electricity consumption mix. These data were used as inputs into NETL's Grid Mix Explorer to estimate the global warming potential of the U.S. electricity profile [62]. The diesel data are representative of NETL's life cycle model of the petroleum supply chain [63]. Steel and concrete data are representative of third-party data [64, 65].

Exhibit 4-9. Mix of primary energy sources used to generate U.S. electricity in 2020 [61]

Primary Energy Source	Year 2020 Mix
Biomass	0.96%
Coal	19.27%
Natural gas	40.48%
Geothermal	0.40%
Hydro	7.11%
Nuclear	19.69%
Other fossil	0.29%
Petroleum	0.43%
Other fuels	0.73%
Solar	2.14%
Solar thermal	0.08%
Wind	8.42%
Total	***100%***

The cradle-to-gate life cycle emissions for the four ancillary processes used in this analysis are provided in **Appendix F** (available in the release package published along with this report).

4.2 Stage Connectivity

The life cycle model used in this analysis normalizes NG system flows to a single basis, the delivery of 1 MJ of NG to consumers. The relationships among supply chain stages do not necessarily represent a single pathway with all stages connected in series. The following complexities must be resolved to normalize all emissions to a basis of 1 MJ of delivered NG:

- Most (but not all) NG goes through gathering and boosting facilities.
- Most (but not all) NG goes through processing facilities.
- NG goes through multiple transmission stations.
- Storage facilities do not represent an NG throughput but an internal loop within the transmission network with storage and withdrawal.
- Some NG is consumed at the city gate and travels only through transmission, while the remainder travels all the way through distribution.

The scaling parameters in **Exhibit 4-10** should be interpreted in the context of an average unit of NG flowing through the supply chain. For example, using the information from the "Expected" column in **Exhibit 4-10**, the pathway for U.S. average NG can be described as follows: after leaving a production site, 90 percent of NG goes through gathering and boosting stations; 75 percent then goes through a processing plant, traveling 600 miles through 10.2 transmission stations, and has a 54 percent chance of going through the distribution network.

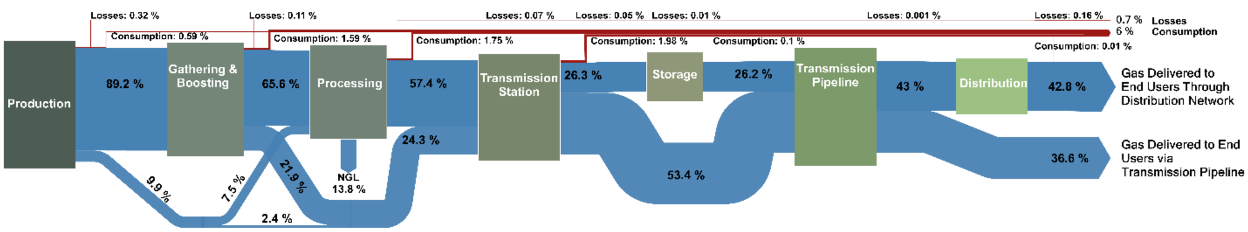
Exhibit 4-10. Stage scaling parameters

Stage (or sub-stage)		Triangular Distributions			Unit	Rationale
		Low	Expected	High		
Production			1		Facility count	NG is extracted from a well exactly one time.
Gathering and Boosting		0.8	0.9	1	Fraction	The fraction of NG that goes through gathering and boosting is based on a measurement study [66].
Processing			0.75		Fraction	This is the fraction of gas that passes through processing [23].
Transmission Station (U.S. Average)		6.8	10.2	14.4	Station count	Transmission station count is based on a literature review of inter- and intrastate transmission station counts, reconciled by average facility throughput to estimate the number of transmission stations between processing and delivery. Regionalized transmission stage scalars were also developed in this update (based on [67]).
Storage			0.33		Dimensionless	The United States has 0.33 units of storage capacity per unit of delivered NG. This factor is the ratio of total underground storage capacity (9.26 Tcf) to annual gas delivered (27.7 Tcf) [68, 69].
Transmission Pipelines (U.S. Average)		540	600	660	Pipeline miles	Data for pipeline blowdown events are translated to an EF in terms of emissions per pipeline mile, thus requiring a corresponding AF in terms of pipeline miles traveled by average NG. The average distance of transmission is 600 miles [3].
Distribution	Midwest		0.81		Fraction	The regional and U.S. average shares of NG that go through distribution are based on transmission and distribution stage regionalization work [67].
	Northeast		0.61		Fraction	
	Pacific		0.80		Fraction	
	Rocky Mountain		0.60		Fraction	
	Southeast		0.36		Fraction	
	Southwest		0.24		Fraction	
	U.S. Average		0.54		Fraction	

The scaling parameters shown in **Exhibit 4-10** are inputs to the model. When scaling the inputs and outputs for each supply chain stage, the NG model also accounts for the NG losses in each stage (NG losses comprise venting and fugitive emissions as well as NG consumed for fuel). The model has a fixed output (1 MJ of delivered NG); a loss at one point in the supply chain induces an increase in upstream flows to maintain a fixed output. Unlike the scaling parameters shown in **Exhibit 4-10,** these stage losses are calculated and applied dynamically in the model. **Appendix A** (available in the release package published along with this report) provides the regional stage-scaling factors for the transmission station and pipeline stages.

Exhibit 4-11 provides a flow diagram designed to explain the NG flows, losses, and consumption rates across the various stages of the 2020 U.S. average NG supply chain to illustrate the inter-connected nature of supply chain stages involved in delivering NG to the end user.

Exhibit 4-11. 2020 U.S. NG supply chain flow diagram, using U.S. average "production through distribution" stages



Notes:

1. The diagram represents a mass accounting of NG (which includes hydrocarbons typically associated with the natural gas supply chain, such as methane, ethane, butane, propane, etc.) and not crude or lease condensate.
2. The NGL output at the processing stage represents bulk NGLs and not a single NGL constituent (ethane, propane, etc.). Losses associated with NGL processing are not represented here.
3. The flow percentages in this diagram are intricately linked with the stage scalars reported in **Exhibit 4-10**. For example, 54% of dry NG (or 43% of total raw NG produced) passes through the distribution stage in the U.S. average scenario.

4.3 Co-product Management

The production of NG co-produces other valuable hydrocarbons (NGLs and crude oil) that share the same infrastructure as NG during production, gathering and boosting, and processing. NG is mixed with other products at the wellhead, in separator equipment, through gathering and boosting systems, and at processing facilities. An objective of most LCAs is to assign emissions to a single product or service, so it is necessary to apportion the emissions from these shared systems among the co-products. The co-production of NG, NGLs, and crude oil should not be confused with the handling of associated gas at oil wells. In instances where associated gas is flared at oil wells, the associated gas is not a part of the NG supply chain—it is a flared byproduct of the petroleum supply chain.

The co-products are in gas and liquid form, requiring the conversion of the product slate to a total energy basis, which is followed by the estimation of an energy allocation factor to allocate emissions between the co-products for the production and gathering stages, and the conversion of the total energy to an equivalent NG basis for the processing stage. The heat content of each co-product is used to make these volume/energy conversions. The following heating values (HHV basis) were used to convert products from a volume basis to an energy basis [70]:

- Crude oil and condensate = 5.8 MMBtu/bbl
- NGL = 3.7 MMBtu/bbl
- Raw NG = 1.235 MMBtu/Mcf
- Processed NG = 1.037 MMBtu/Mcf

The methodology followed by Roman-White et al., which relies on the Natural Gas Sustainability Initiative Methane Emissions Intensity protocol and ONE Future Methane Emissions Estimation protocol [71, 70, 23], was followed for allocating emissions between the various co-products of the NG supply chain for this update. In certain cases, exceptions to the protocols were made in case GHGRP data provided a high enough level of granularity that enabled partitioning (International Organization for Standardization preferred technique) [23]. Both the production and the gathering and boosting stages allocate emissions across the raw NG and crude oil and lease condensate streams, whereas the processing stage allocates emissions across the processed dry NG and NGL streams. **Exhibit 4-12** summarizes the accounting methodology for the various emission sources across the production, gathering and boosting, and processing stages.

Exhibit 4-12. Emissions accounting techniques for NG supply chain co-products

Emission Source	NETL Unit Process	Accounting Technique
Production		
Liquids unloading	Liquids unloading	Energy allocation
Pneumatic devices	Venting	Energy allocation
Reciprocating compression (compressor driver)	Compression	Partition to NG
Flare stacks	Flaring	Energy allocation
Combustion (non-compressor driver)	Combustion	Energy allocation
Equipment leaks (gas services)	Fugitives	Partition to NG
Acid gas removal	AGR	Partition to NG
Completions and workovers	Venting	Energy allocation
Dehydrators	Venting	Partition to NG
Vessel blowdowns	Venting	Energy allocation
Compressor blowdowns	Venting	Partition to NG
PRV upsets	Venting	Energy allocation
Gathering and Boosting		
Pneumatic devices	Venting	Energy allocation
Reciprocating compression (compressor driver)	Reciprocating compression	Partition to NG
Centrifugal compression venting	Centrifugal venting	Partition to NG
Flare stacks	Flaring	Energy allocation
Combustion (non-compressor driver)	Combustion	Energy allocation

Emission Source	NETL Unit Process	Accounting Technique
Acid gas removal	AGR	Partition to NG
Dehydrators	Venting	Partition to NG
Compressor blowdowns	Venting	Partition to NG
All other blowdowns	Venting	Energy allocation
Mishaps	Venting	Energy allocation
Equipment leaks (gathering pipelines)	Fugitives	Energy allocation
Equipment leaks (gas services)	Fugitives	Partition to NG
Processing		
Pneumatic devices	Venting	Energy allocation
Reciprocating compression (compressor driver)	Reciprocating compression	Partition to NG
Centrifugal compression	Centrifugal compression	Partition to NG
Flare stacks	Flaring	Energy allocation
Acid gas removal	AGR	Partition to NG
Dehydrators	Venting	Partition to NG
Blowdowns	Venting	Energy allocation
Equipment leaks	Fugitives	Energy allocation

4.4 Gathering and Boosting Stage Updates

DOE's Office of Fossil Energy and Carbon Management awarded contracts to external institutions to research quantification of methane emissions in the NG supply chain to improve the accuracy of methane emission estimates. NETL reviewed two measurement campaign projects specific to the gathering and boosting stage of the NG supply chain [57, 58]. The results of these studies improve upon the understanding of methane emissions. The measurement-informed study results have been incorporated into this study to improve the accuracy of the emissions factors. The measurement informed data replaced the GHGRP parameters used in the previous version of the NETL NG life cycle model [4].

Two types of updates were made to the parameters and unit processes in NETL's NG life cycle model [4]: the factors that align directly with the model (**Exhibit 4-13)**, and the factors that match the emission sources but are at a different parameter level (**Exhibit 4-14**). The updates were made as follows:

- The parameters in **Exhibit 4-13** were updated by changing the relevant parameters in the NG model.
- The parameters in **Exhibit 4-14** were updated by adding new parameters to the NG model. Previously, the NG model directly pulled the CH4 emissions values reported to the GHGRP [12]. Now, the NG model uses the EFs listed in **Exhibit 4-14** and the bootstrapped average of the activity data (equipment and component count and operating hours) reported to the GHGRP.

Exhibit 4-13. Factors directly aligned with NETL's model

Gathering and Boosting (GSI [57])				Parameter in NG Model Prior to Update	Revised Parameters for NG Model (95% mean confidence intervals)			
Parameter	Population EF (scf/device-hr)	Sample Count	Std dev of emission rate (scf/device-hr)		Parameter ID	Low	Expected	High
Pneumatic device, low bleed, EF	3.6	8	1.6	1.4	2_PDlb_EF	2.5	3.6	4.7
Pneumatic device, high bleed, EF	38.1	8	26.9	37.5	2_Pdhb_EF	19.1	38.1	57.1
Pneumatic device, intermittent bleed, EF	12.8	85	23.9	13.6	2_PDib_EF	7.6	12.8	18.0
Pneumatic device, pump, EF	8.8	3	4.88	13.4	2_Ppump_EF	3.2	8.8	14.4

Exhibit 4-14. Factors that match NETL's emission sources but at a different parameter level

Gathering and Boosting [58]				Representation in NG Model Prior to Update	Parameter Currently in GHGRP or GHGI	Mean Uncertainty (95% confidence interval)		
Equipment	Mean Population	Emission Factor (scfh CH_4)				Low	Expected	High
AGR unit	8	3.61		AGR CH_4 EF	3.73E-05 kg CH_4/kg NG	2.03	3.61	5.19
Compressor	435	94.4		Annual CH_4 emissions reported by operators	12.0 scfh CH_4	90.2	94.4	98.6
Gathering and Boosting (GSI [57])				Representation in NG Model Prior to Update	Parameter Currently in GHGRP or GHGI	Mean Uncertainty (95% confidence interval)		
Component	Population EF (scf/hr/comp)	Sample Count	Total Measured Emissions (scf/hr)		scf/hr/comp	Low	Expected	High
Valve	0.042	6,393	266	Annual CH_4 emissions reported by operators	1.27	N/A	0.042	N/A
Connector	0.003	43,575	113	Annual CH_4 emissions reported by operators	0.33	N/A	0.003	N/A
PRV	1.41	385	544	Annual CH_4 emissions reported by operators	1.22	N/A	1.41	N/A

4.5 Processing Stage Regionalization and Throughput Estimation

In the previous iteration of the NG report, the processing stage for each basin was modeled using U.S. average data obtained from GHGRP [12]. As part of this update, the processing stage data were regionalized by mapping each processing facility reporting to GHGRP to the nearest production basin based on its geographical coordinates. Since GHGRP does not provide the volumes of processed NG and NGLs exiting a processing facility (also referred to as facility throughput), these volumes were estimated using regionalized pre-processing composition data (as provided in **Section 3.1**) and reported recovery efficiency of NGL components from NG processing plants. **Exhibit 4-15** provides a breakdown of NG processing plants in the United States by technology employed for separating NGLs from the inlet gas stream [72]. In this analysis, the provided proportions for the absorption, refrigeration, and cryogenic technology types were extrapolated to 100 percent to represent all processing plants in the United States.

Exhibit 4-15. Breakdown of U.S. NG processing plants

Technology	Proportion of Total Plants
Absorption	1%
Refrigeration	20%
Cryogenic	68%
Refrigeration in combination with cryogenic or absorption methods	11%

Plant flow data from Form EIA-757 were used as the foundation for modeling regionalized average processing facility throughputs [73]; however, since the latest available information from the form was based on the 2017 data year, the processing facility flows were scaled up by 22 percent to account for the rise in total U.S. NG production from 2017 to 2020 [11]. An average processing stage loss factor of 3.12 percent of input flow was considered to estimate the volume of product stream (including both NG and NGLs) exiting the facility [5]. The NGL yield (gallons of NGLs per Mcf of raw gas) was estimated by means of a gas composition analysis that calculated the entrained volume of each NGL component in the raw NG produced in each basin [74]. The final outputs of the processing facility are processed dry NG and NGLs. **Exhibit 4-16** provides the recovery efficiency of each NGL component as a function of processing plant technology type [75].

Exhibit 4-16. Recovery efficiency of NGL components by processing plant technology

NGL Component	Absorption	Refrigeration	Cryogenic	Custom (estimated)
Ethane	0.15–0.30	0.80–0.85	0.85–0.90	0.83–0.88
Propane	0.65–0.75	1	1	1
Butanes	1	1	1	1
Pentanes and C5+	1	1	1	1

Note: The custom mix was estimated by weighting the recovery efficiency for each technology type by its corresponding proportion of total processing plants (as reported in **Exhibit 4-15**).

Based on the NGL recovery rates reported above, the post-processing NG compositions were estimated for each basin. **Exhibit 4-17** reports the mass compositions for post-processing NG from each basin.

Exhibit 4-17. Post-processing NG composition by basin (mass fraction)

Basin	Carbon Dioxide	Methane	Nitrogen	Ethane	iso-Butane	iso-Pentane	n-Butane	n-Pentane	Propane	Undefined VOC
Anadarko	0.00E+00	8.98E-01	8.34E-02	1.87E-02	1.75E-06	1.19E-06	3.56E-06	1.06E-06	2.84E-04	0.00E+00
Appalachian	2.45E-04	9.52E-01	3.44E-02	1.31E-02	6.69E-07	3.68E-07	1.23E-06	4.18E-07	1.15E-04	0.00E+00
Arkla	1.90E-03	9.31E-01	5.94E-02	7.44E-03	9.93E-07	5.65E-07	1.05E-06	4.11E-07	6.01E-05	0.00E+00
Arkoma	1.55E-04	9.60E-01	3.50E-02	4.68E-03	7.59E-08	7.68E-08	1.61E-07	6.80E-08	2.25E-05	0.00E+00
East Texas	2.89E-03	9.31E-01	5.07E-02	1.54E-02	6.98E-07	2.34E-07	5.93E-06	8.16E-07	6.34E-05	0.00E+00
Fort Worth	0.00E+00	8.84E-01	8.28E-02	3.29E-02	2.77E-06	1.71E-06	5.10E-06	1.51E-06	4.57E-04	0.00E+00
Green River	1.60E-03	9.55E-01	2.86E-02	1.43E-02	1.61E-06	9.95E-07	1.87E-06	5.99E-07	1.61E-04	0.00E+00
Gulf Coast	1.54E-03	9.70E-01	1.63E-02	1.20E-02	1.51E-06	7.66E-07	1.52E-06	6.10E-07	1.30E-04	0.00E+00
Permian	6.76E-03	8.91E-01	8.00E-02	2.17E-02	1.48E-06	9.83E-07	2.87E-06	8.55E-07	2.41E-04	0.00E+00
Piceance	1.23E-02	9.15E-01	4.90E-02	2.37E-02	1.68E-06	1.07E-06	1.89E-06	6.02E-07	1.89E-04	0.00E+00
San Juan	9.67E-03	9.60E-01	1.56E-02	1.48E-02	1.49E-06	7.83E-07	1.86E-06	5.56E-07	1.85E-04	0.00E+00
South Oklahoma	0.00E+00	9.05E-01	6.88E-02	2.57E-02	1.19E-06	7.89E-07	2.97E-06	9.84E-07	2.20E-04	0.00E+00
Strawn	0.00E+00	8.93E-01	8.32E-02	2.33E-02	1.33E-06	9.38E-07	2.53E-06	5.79E-07	2.20E-04	0.00E+00
Uinta	4.71E-03	9.67E-01	1.81E-02	9.90E-03	1.10E-06	7.27E-07	1.29E-06	5.50E-07	1.23E-04	0.00E+00

As part of the gas composition analysis, it was ensured that the processed NG meets pipeline quality specifications as listed in **Exhibit 4-18** [76].

Exhibit 4-18. Pipeline quality gas specifications

Characteristic	Specification
HHV	950–1200 Btu/scf
N_2 content	4–5 mol%
Total inert content (N_2 + CO_2)	4–5 mol%

Exhibit 4-19 reports the entrained volume of NGLs estimated based on the composition of raw NG (pre-processing) produced in each basin.

Exhibit 4-19. Entrained volumes of NGLs in raw NG from each basin

Basin	Entrained NGLs (gallons per Mcf)
Appalachian	1.59
Gulf Coast	1.65
Arkla	1.03
East Texas	1.98
Arkoma	0.49
South Oklahoma	3.03
Anadarko	3.13
Strawn	2.87
Fort Worth	4.42
Permian	2.86
Green River	1.96
Uinta	1.42
San Juan	2.02
Piceance	2.73

Exhibit 4-20 summarizes the estimated NG and NGL processing facility throughput values estimated for each basin.

Exhibit 4-20. Estimated processing stage facility throughputs for each basin

Basin	NG Throughput (Mcf)	NGL Throughput (bbl)
Appalachian	8.00E+07	3.20E+06
Gulf Coast	7.22E+07	3.01E+06
Arkla	3.13E+07	7.92E+05
East Texas	2.79E+07	1.41E+06
Arkoma	4.67E+07	5.54E+05
South Oklahoma	3.61E+07	2.90E+06
Anadarko	3.52E+07	2.93E+06
Strawn	3.22E+07	2.44E+06
Fort Worth	3.33E+07	4.12E+06
Permian	3.69E+07	2.81E+06
Green River	5.41E+07	2.70E+06
Uinta	1.33E+07	4.70E+05
San Juan	1.01E+08	5.19E+06
Piceance	9.95E+07	7.13E+06
Weighted Average	**4.84E+07**	**2.82E+06**

It is worth noting that the use of regional pre-processing composition data for calculating the throughput of a processing facility underestimates the proportion of NGL components in the produced NG, resulting in a higher ratio of processed dry NG (Mcf) to NGLs (17 Mcf dry NG/bbl NGL) as compared to the value estimated using total NG and NGL production in the United States for 2020 (13 Mcf dry NG/bbl NGL) [77]. Updating the ratio of processed NG to NGLs from 17 to 13 Mcf dry NG/bbl NGL would result in an increase in U.S. average GHG emissions intensity of 8 percent (IPCC AR6, 100-yr GWP basis).

4.6 Transmission and Distribution Stage Updates

Littlefield et al. [67] provide the complete methodology followed for regionalizing the transmission and distribution stages. This update aims to provide a detailed life cycle perspective on the variation of GHG emissions according to the production and delivery locations of NG. As part of this update, transmission and distribution stage GHGRP data for 2020 were disaggregated into six regions (see **Exhibit 4-21**), NG supply and demand were balanced to estimate the likely pathways and their distances between production and delivery, and new data on commercial and industrial distribution meters were incorporated. The average, straight-line transmission distance for U.S. NG ranges 25–1,693 miles across 101 likely production-to-delivery pairings [67].

Exhibit 4-21. Six regions for U.S. NG delivery

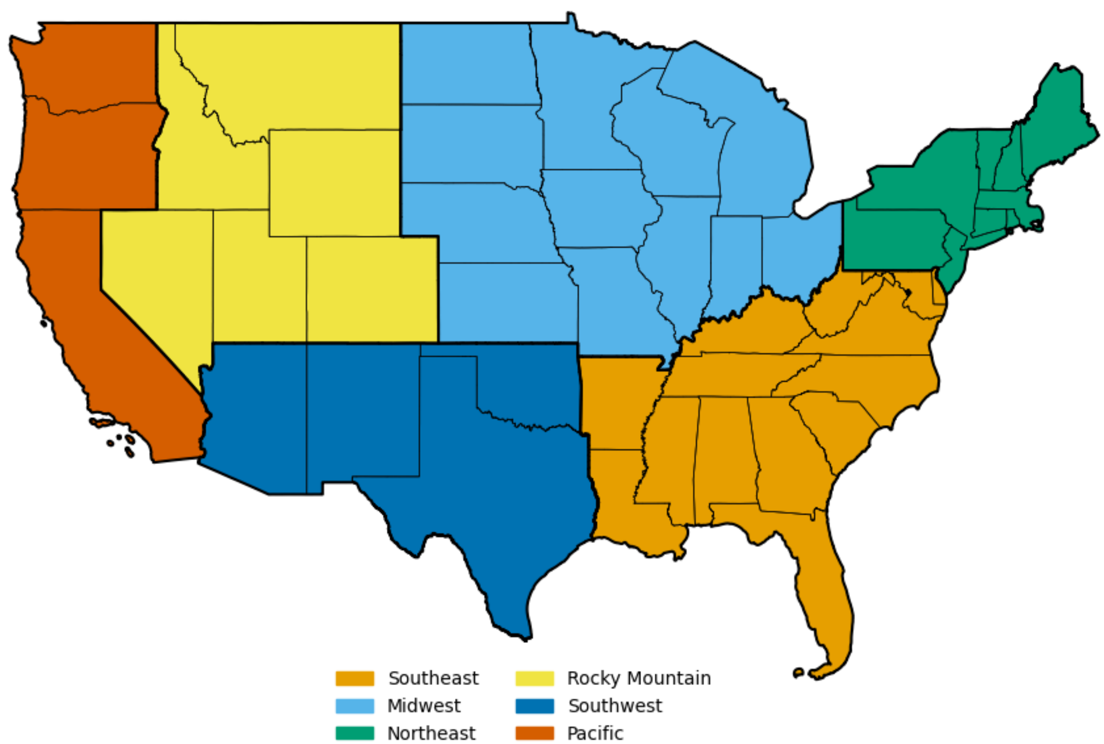


Exhibit 4-22 provides the expected transmission distances incorporated into the model from the upstream production to the downstream delivery region.

Exhibit 4-22. Expected straight-line transmission distance between production and delivery regions (miles)

Upstream ↓	Downstream →	Consumption					
		Midwest	Northeast	Pacific	Rocky Mountain	Southeast	Southwest
Processing	Midwest	265	214	-	-	-	-
	Northeast	228	245	-	-	332	-
	Pacific	-	-	25	-	-	-
	Rocky Mountain	720	-	727	237	-	711
	Southeast	-	-	-	-	166	-
	Southwest	876	1693	-	-	977	299

These distances were used to estimate regionalized transmission stage scalars for each production and delivery combination in the NG model. In addition, the regionalization work by Littlefield et al. [67] was used to estimate regionalized stage scalars for the distribution stage (see **Exhibit 4-10**), where the study relied on the Homeland Infrastructure Foundation-Level Database that provides NG local distribution company service territory and volume data. **Appendix A** (available in the release package published along with this report) provides the regional stage-scaling factors for the transmission station and pipeline stages, and **Appendix H** (available in the release package published along with this report) reports the complete list of all feasible combinations of upstream production basins and downstream transmission and distribution (delivery) regions analyzed in this work.

GHGRP-reported methane emissions from centrifugal and reciprocating compressor venting were scaled by a factor of 4.0 and 4.5, respectively, based upon work by Zimmerle et al. [59]. This is similar to the methodology followed by Roman-White et al. [23] for better characterization of emissions from GHGRP-reported venting.

This work also incorporated updated EFs for commercial and industrial customer meter sets based on work by the Gas Technology Institute for DOE [60], involving field measurement campaigns for commercial/industrial meters across six geographical regions in the United States. Moore et al. [60] explain the methodology followed for estimating updated EFs for customer meters in additional detail and highlight the discrepancy between factors estimated through their measurement campaign and the GHGI data [19]. **Exhibit 4-23** summarizes the EFs and their confidence intervals for commercial and industrial customer meter sets [60].

Exhibit 4-23. Emission factors and confidence intervals for commercial and industrial meters (kg CH_4/meter-yr)

Region	Commercial		Industrial	
	Mean	95% Confidence Interval	Mean	95% Confidence Interval
All	57.4	(35.3, 82.5)	117.8	(64.8, 179.8)
Midwest	28.4	(6.3, 61.1)	52.3	(17.4, 98.4)
Northeast	20	(11.1, 30.4)	172.5	(20.9, 416.1)
Pacific	4	(1.9, 6.6)	17.4	(1.5, 46.6)
Rocky Mountain	108.4	(1.9, 312.9)	322.5	(10.4, 769.2)
Southeast	139.3	(0.6, 403.2)	291.7	(58.1, 686.3)
Southwest	153.9	(80.0, 241.1)	372.9	(83.9, 765.3)

5 NATURAL GAS BASELINE REPORT MODELING CHANGES, DATA UPDATES, AND UNCERTAINTY

5.1 SUMMARY OF MODELING CHANGES AND DATA UPDATES

This section summarizes the main modeling changes and data updates made since the previous version of this report and the NG model.

- **Inclusion of new measurement-informed data in the NG model**
  This work incorporates a range of new measurement-informed data from multiple literature sources to estimate the national and regional NG emissions profiles. These include:
  - Updated EFs for reciprocating compression, fugitive emissions, and pneumatic device venting for the gathering and boosting stage (see **Section 4.4**)
  - Inclusion of regional EFs for commercial and industrial meters used in the distribution stage (see **Section 4.6**)
  - Inclusion of distribution stage scalars, developed based on Littlefield et al. (see **Section 4.6**)
  - Improved methane emissions accounting for transmission-compression venting based upon Zimmerle et al. [59] and Roman-White et al. (see **Section 4.6**) [23]
- **Estimation of production shares by well type and geography**
  This work relies on the GHGRP data for estimating production shares for all 27 onshore basins and refers to EIA data to estimate production shares for the two offshore scenarios. The earlier version of the report used data from Enverus (formerly DrillingInfo) to estimate production shares [15]; however, the push toward greater transparency through utilization of publicly available data has led to a revision of the production share estimation methodology. Refer to **Appendix G** for the detailed methodology for estimating production shares used in this work. **Exhibit 5-1** compares the variation in production shares by well type and geography across the 2019 NG baseline report (2016 data year) [4], 2021 ONE Future report (2017 data year) [5], and this work (2020 data year).

Exhibit 5-1. Comparison of gas production shares by well type and geography across NETL NG studies

Techno-basin	Production Shares		
	2019 NG Baseline Report (2016 data year)	2021 ONE Future Report (2017 data year)	Current Report (2020 data year)
Alaska – offshore	0.10%	0.14%	0.14%
Anadarko – conv	2.20%	1.19%	1.83%
Anadarko – shale	2.60%	2.62%	2.64%
Anadarko – tight	1.70%	2.81%	1.90%
Appalachian – shale	29.00%	22.59%	38.68%
Arkla – conv	0.40%	1.77%	3.30%
Arkla – shale	4.20%	3.45%	5.78%
Arkla – tight	1.40%	1.44%	0.90%
Arkoma – conv	0.30%	0.60%	0.55%
Arkoma – shale	0.90%	0.69%	1.76%
Associated[a]	16.10%	22.47%	0.00%
East Texas – conv	1.60%	0.97%	0.81%
East Texas – shale	1.30%	0.33%	0.70%
East Texas – tight	1.30%	2.01%	3.78%
Fort Worth – shale	1.80%	1.55%	0.89%
GoM – offshore	4.20%	3.83%	2.81%
Green River – conv	1.60%	0.94%	0.06%
Green River – tight	3.90%	3.33%	2.64%
Gulf – conv	0.80%	4.38%	2.72%
Gulf – shale	6.60%	3.41%	3.52%
Gulf – tight	1.30%	0.94%	0.77%
Permian – conv	2.30%	3.98%	9.76%
Permian – shale	5.30%	6.80%	7.09%
Piceance – tight	0.30%	1.57%	1.87%
San Juan – CBM	1.90%	2.11%	0.93%
San Juan – conv	1.40%	0.26%	0.00%
San Juan – shale	0.00%	0.00%	1.08%
South Oklahoma – shale	1.00%	0.91%	0.95%
Strawn – shale	3.20%	2.18%	1.52%
Uinta – conv	0.50%	0.04%	0.03%
Uinta – tight	0.80%	0.69%	0.59%

[a] This work assigns associated gas production volumes (i.e., gas produced from oil wells) from various facilities to other non-oil formation types. Unlike previous NETL NG modeling, associated gas production is not modeled as a separate profile in this work, and instead these volumes are embedded under existing techno-basin categories. Refer to **Appendix G** for additional details.

- **Inclusion of new emission categories for alignment with EPA's GHGI**
  This work incorporates EF and AF data for newer emission-source categories based on EPA's GHGI. Future versions of this report will seek to regionalize and characterize uncertainty for these emissions. These emission sources include:
  - Production
    - Separators
    - Meters/piping
  - Gathering and boosting
    - Atmospheric tanks
    - Yard piping
  - Transmission and storage
    - M&R stations
      - Transmission company interconnect
      - Farm taps and direct sales

Exhibit 5-2 provides the various GHGI AFs and EFs [6] incorporated into the NETL NG model.

Exhibit 5-2. GHGI AFs and EFs for newly incorporated emission categories

Stage	Emission Source	Parameter Type	Unit	Value
Production	Separators	AF	separator count	2.91E+05
		CH_4 EF	kg/separator	3.83E+02
		CO_2 EF	kg/separator	6.08E+01
	Meters/piping	AF	meter count	3.44E+05
		CH_4 EF	kg/meter	2.03E+02
		CO_2 EF	kg/meter	2.93E+01
Gathering and Boosting	Atmospheric tanks	AF	tank count	4.36E+04
		CH_4 EF	kg/tank	5.61E+03
		CO_2 EF	kg/tank	2.16E+04
	Yard piping	AF	station count	7.43E+03
		CH_4 EF	kg/station	1.26E+04
		CO_2 EF	kg/station	1.51E+03
Transmission and Storage	M&R – transmission company interconnect	AF	station count	2.69E+03
		CH_4 EF	kg/station	2.80E+04
		CO_2 EF	kg/station	8.25E+02
	M&R – farm taps & direct sales	AF	station count	7.97E+04
		CH_4 EF	kg/station	2.19E+02
		CO_2 EF	kg/station	6.46E+00

A detailed comparison of emission intensities between this work and EPA's GHGI is provided in **Section 9.1**. The observed differences in emission intensities reflect the differing modeling choices of the two studies.

- **Pre- and post-processing NG density and heating value**
  Previous work utilized a consistent NG density across all stages of the NG supply chain—0.042 lb/scf—however, this work estimates a pre-processing NG density value for each regional profile based on its pre-processing composition data, whereas the post-processing NG density is based on typical pipeline NG specification of 0.044 lb/scf. Additionally, the HHV of post-processing NG was updated to 1,037 Btu/scf based on 2020 EIA data [78].
- **Post-processing composition data**
  This work estimates basin-specific post-processing NG composition data instead of relying on a single U.S. average estimate for all basins. **Section 4.5** explains the methodology for estimating post-processing composition values for all basins that meet pipeline-quality NG specifications.
- **Energy allocation of emissions between NG and NG supply-chain co-products**
  The 2019 NG baseline report filters out emissions from oil wells for all scenarios (excluding associated gas), whereas this work goes a step further and allocates emissions between the various NG supply chain co-products such as lease condensates, NGLs, etc. **Section 4.3** discusses the various emissions accounting techniques for the NG supply chain co-products.
- **Regionalization of processing-, transmission-, and distribution-stage data**
  This update relies on the transmission and distribution regionalization work by Littlefield et al. [67] for assessing the regional variation in GHG emissions intensity of NG produced from different basins. In addition, NG processing facilities reporting to GHGRP are mapped to their nearest basins based on their locations. **Section 4.5** and **Section 4.6** provide additional details regarding this update.
- **Estimated ultimate recovery data update**
  Section 3.2 provides the methodology for estimating the updated gas and oil EUR values for the different basins, speciated by formation type.
- **Revised liquids unloading factors**
  This update relies on work by Zaimes et al. and uses Enverus data representative of the 2020 operating year to generate revised TNME estimates by basin and well type [15]. Refer to **Section 3.3.3** and **Appendix D** for additional details regarding updates to the TNME values for liquids unloading.
- **Inclusion of alternate life cycle boundary scope**
  In addition to studying results on a "production through distribution" life cycle boundary, this work also presents life cycle results on a "production through transmission network" boundary. These results are provided to account for the scenarios where NG is delivered directly to end users from the transmission network (power

plants, large industrial users) before it enters the distribution network. **Section 2.1** and **Section 2.2** provide additional details regarding the scope of this work.

- **Updated bootstrapping methodology for estimating compression energy parameters**
  Since the release of the 2019 NG baseline report [4], certain modeling changes that better reflect NG consumption rates for the reciprocating and centrifugal compression categories have been implemented. These changes include updating the methodology for estimation of compression energy in the NG model. In the 2016 version of the model (published in the 2019 NG baseline report), the compression power capacity (HP) and operating hours parameters at the facility level were bootstrapped separately, and these bootstrapped values were multiplied in the model, resulting in a much higher NG consumption rate (and in turn, emissions) than expected.

  This methodology was revised to estimate compression energy values (HPh) for each equipment type (reciprocating or centrifugal) prior to bootstrapping and, finally, bootstrapping these HPh values at the facility level to reflect a much more realistic NG consumption rate that is rooted in actual compression energy (HPh) instead of compressor power capacity (HP).

5.2 Uncertainty

All models include uncertainty, which may come from inconsistent definitions, measurement error, sample bias, unobserved evidence, structural uncertainty, and empirical uncertainty [79]. For this study, uncertainty resulting from inconsistent definitions and measurement errors is assumed negligible in that data used in this analysis have consistent definitions and reflect samples nationally representative of modeled processes. Unobserved evidence, often called "known unknowns," is expected in a complex and highly distributed system characteristic of NG infrastructure. Examples include unobserved stochastic events that emit fugitive methane. However, it is not feasible to estimate and model uncertainty from missing observations.

The model does include both structural and empirical uncertainty and may include sample bias. Structural uncertainty, also called "model uncertainty" or "epistemic uncertainty," occurs because the mathematical representations of the world are incomplete. A simple example of structural uncertainty is the assumption that electricity used in pumps scales linearly with pump HP (**Section 4.1.6**). Empirical uncertainty relates to uncertainty about the values characterizing these structural relationships. For example, pumps are modeled at their rated HP. Much of the empirical uncertainty in the model comes from unexplained variability, which reflects measurements or estimates of the same value that vary for unknown reasons. Natural and technological variability are the primary sources of unexplained variability in the data summarized in this report. For example, the quantity of NG available for recovery, the composition of NG, and the splits of gas, oil, and NGLs are natural phenomena that vary from basin to basin. Examples of technological variability include the profiles of pneumatic controllers (which comprise low-, intermittent-, and high-bleed devices), the mixes of compression technologies (centrifugal and reciprocating), and the types of seals used around the rotating shafts of centrifugal compressors (wet and dry seals). Sample biases may be present in data collected outside of year 2020 or in small samples presumed representative of a broader population.

Examples of structural uncertainty, empirical uncertainty, and potential sample biases in the model include, but are not limited to the following:

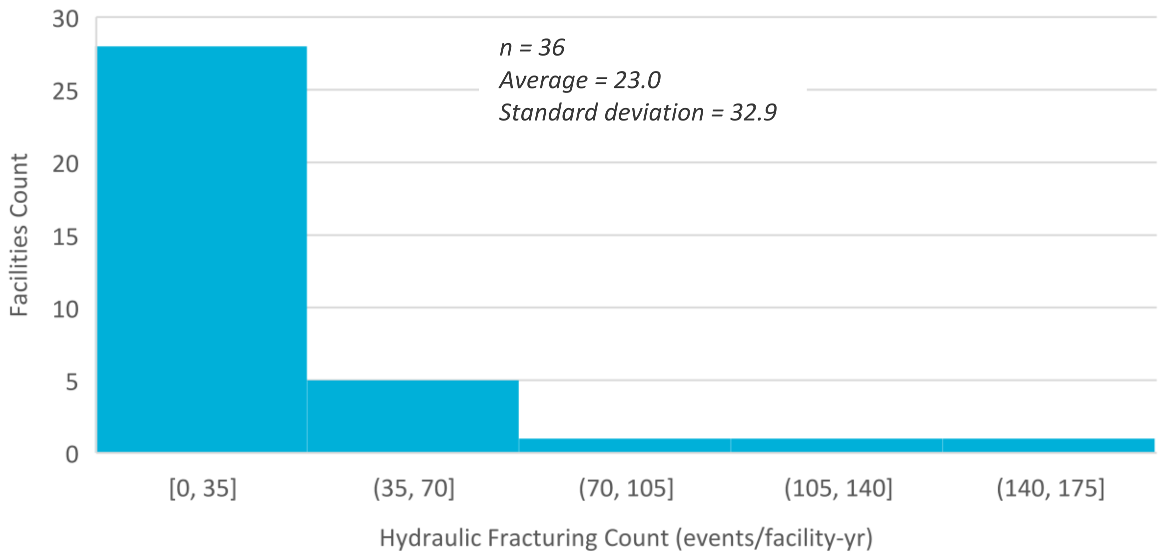
- Methods linking supply chain stages into a single, integrated supply chain (as discussed in **Section 4.2**) include both structural and empirical uncertainty.
- The mathematical model representing emissions from liquids unloading (as discussed in **Section 3.3.3**), empirical representation of unexplained variability in model inputs, and use of older data in estimating model inputs all contribute to uncertainty.
- Uncertainty is caused by the double-counting of gathering and boosting throughput by the GHGRP (as discussed in **Section 3.3.1**) [12].
- The methods to regionalize processing-stage NG and NGL throughputs include structural and empirical uncertainty in regionalizing throughput and may include sample bias in the use of older data and small samples (as discussed in **Section 4.5**).
- The methods used to estimate production shares by well type and geography include both structural and empirical uncertainty (as discussed in **Section 5.1**).
- Assumed methane emissions from marginal wells may include temporal or small-sample biases (as discussed in **Section 2.3**).

Uncertainty can only be mitigated by additional data collection and analysis. Absent mitigation, measurable uncertainty, such as unexplained variability, can be modeled to understand how it impacts results. Assumptions, methods, and references have been documented to ensure model transparency for uncertainty sources that cannot be modeled, such as structural uncertainty or sample bias.

Unexplained variability is modeled by reflecting affected inputs not as single-point, deterministic values but as distributions. Distributions can be estimated either by randomly and repeatedly sampling actual observations or by fitting the raw observations to a theoretical distribution for sampling. This study takes the latter approach.

Most of the data have positively skewed probability distributions. **Exhibit 5-3** is an example from the GHGRP data that shows the skewness of hydraulic fracturing event counts in Appalachian shale [12]. This example shows that most production facilities have fewer than 35 hydraulic fracturing events per facility-year and that the entire data set has an average event count of 23 events/facility-yr. However, as indicated by the standard deviation of 32.9 events/facility-yr, the data are highly variable. (Note that **Exhibit 5-3** uses the GHGRP definition of a facility, which includes all of the production sites owned by an operator in a region [12].)

Exhibit 5-3. Distribution of data for Appalachian shale hydraulic fracturing events

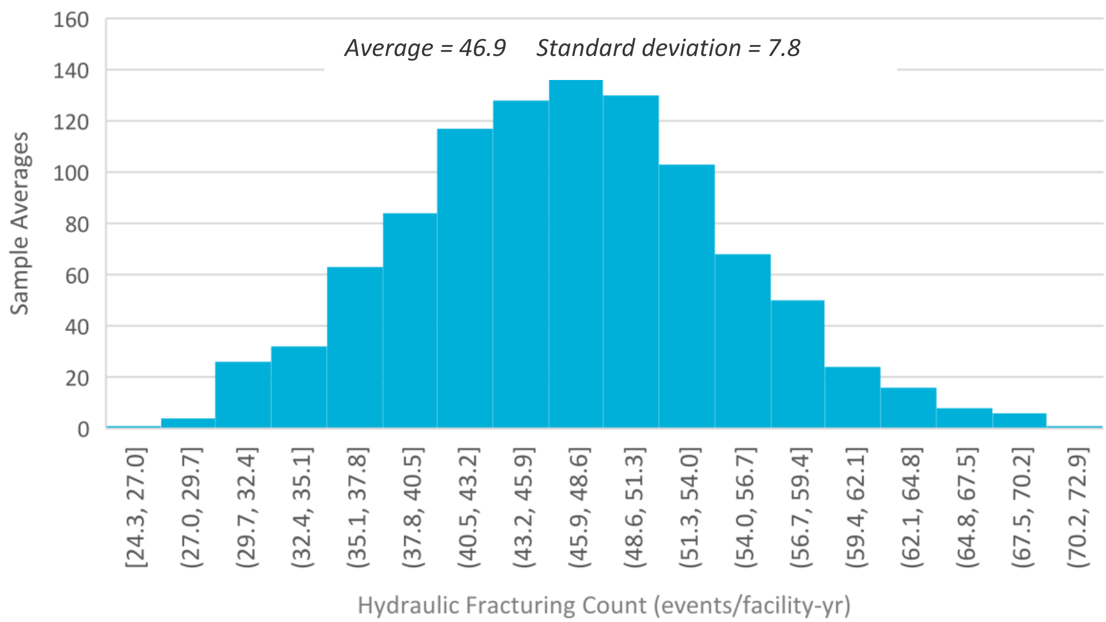


Another complication with skewed distributions is that a higher number of samples may be required to reliably fit them with a curve or to determine their statistical parameters (mean, standard deviation, etc.). For example, the distribution of discrete values in **Exhibit 5-3** comprises 36 data points, which may be an adequate sample size to represent a normally distributed population but insufficient to adequately represent a skewed population with extreme values.

The objective of this analysis is to calculate the *average emissions* from NG, not the probability that a *randomly selected unit of NG* has a given GHG emission profile. The central limit theorem indicates that randomly sampled means from a population with a sufficiently large sample size will be normally distributed. Therefore, the modeling of unexplained input variability is simplified by estimating distributions of means from random and repeated samples with replacement of the raw data. This approach allows modeling of all sufficiently sized inputs as normally distributed. So, even if a population has a skewed distribution, the confidence in the average value for the population is normally distributed. The distribution in **Exhibit 5-4** was constructed by taking the production-weighted average of 1,000 samples from data in **Exhibit 5-3**. Comparing **Exhibit 5-3** and **Exhibit 5-4** demonstrates how the *average* values from repeated samplings from a skewed distribution do indeed approach a normal distribution.

It is important to correctly interpret and apply the distributions derived using this approach. The frequencies from the resulting distributions reflect the probability of a randomly drawn sample mean. While the mean of sample averages maps well to the mean of the underlying raw distribution, off-mean quantiles (e.g., 95 percent) or measures of variation (e.g., standard deviation) for the distribution of means will not map well to the respective statistics for the underlying raw data, particularly for skewed or bimodal data.

Exhibit 5-4. Distribution of sample averages for Appalachian shale hydraulic fracturing events



Statistical bootstrapping is a numerical method that is consistent with the analytical method for computing the standard error of the mean. The data for the *entire* population are not available, warranting the calculation of the error inherent in the *sample* population. By using statistical bootstrapping, this analysis characterizes the uncertainty in average emissions by considering both the variability and size of sample data.

Distributions of randomly sampled means were estimated for input parameters with sufficient sample sizes. These parameters were then modeled as triangular distributions by mapping the average, 2.5th quantile, and 97.5th quantile values to the average, minimum, and maximum values, respectively, defining the triangular distribution. There are not enough data to estimate a distribution of means for some parameters, such as the flows of produced water and flowback water (as discussed in **Section 3.6**). In these cases, variability is modeled as a uniform distribution whose parameters are defined by the minimum and maximum observations, with the expected value centered between these extremes.

Monte Carlo analysis was applied to input distributions to propagate unexplained variability from inputs into outputs. The Monte Carlo routine randomly, independently, and repeatedly samples each input parameter 500 times using Latin hypercube sampling to prepare output distributions with fewer sample values. The resulting output mean, 2.5th quantile, and 97.5th quantile are reported.

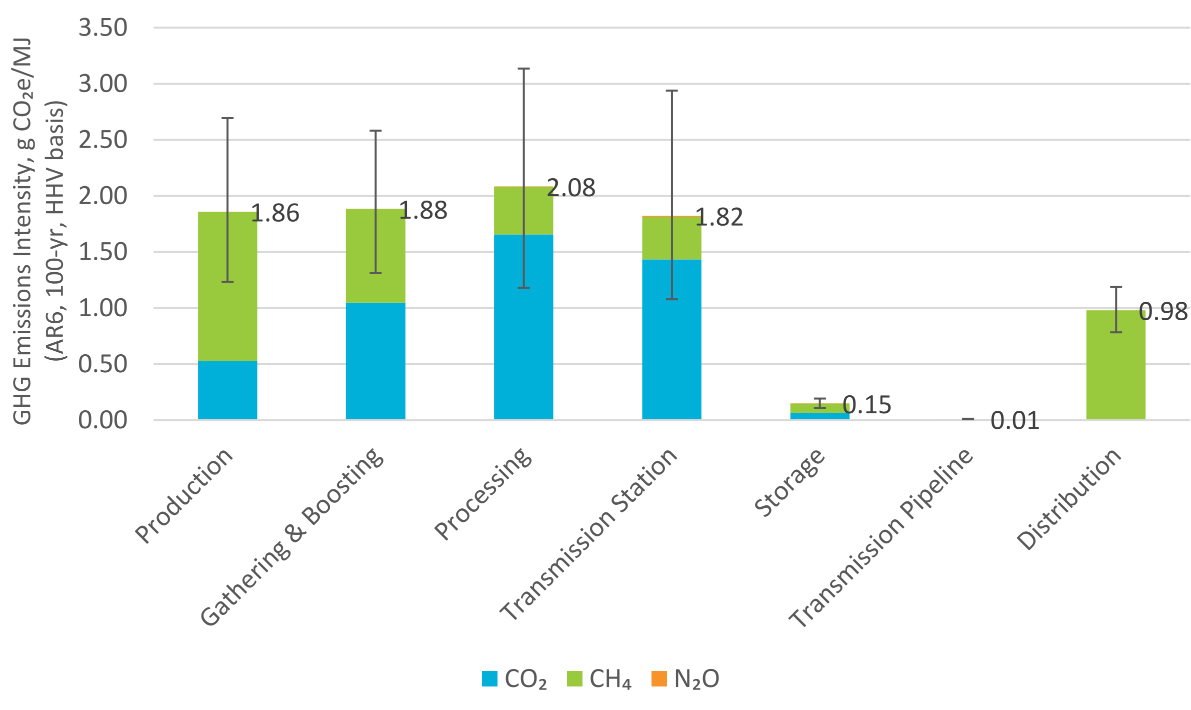
6 Results

The life cycle results include findings on national average as well as regionalized GHG emissions, water use, other air emissions, and water emissions. This section primarily discusses results for the "production through distribution" life cycle boundary. Refer to **Appendix E** (available in the release package published along with this report) to obtain detailed results for the "production through transmission network" life cycle boundary. While this report discusses GHG emissions in detail, it recognizes the importance of other impact categories and provides a complete inventory of emissions to air and water enabling the assessment of other key impacts by researchers. The full inventory of life cycle results for each scenario is provided in **Appendix F** (available in the release package published along with this report).

6.1 Greenhouse Gas Emissions

For the "production through distribution"-stage life cycle boundary, the national average life cycle GHG emissions are 8.8 g CO_2e/MJ (with a mean confidence interval of 5.7–12.7 g CO_2e/MJ, AR6 100-yr GWP basis). For the "production through transmission network" life cycle boundary, the national average life cycle GHG emissions are 7.8 g CO_2e/MJ (with a mean confidence interval of 4.9–11.5 g CO_2e/MJ, AR6 100-yr GWP basis). CO_2 and CH_4 are the predominant GHG emissions in this profile. N_2O and other GHG emissions do not contribute significantly to the results. The GHG emissions from each supply chain stage are shown in **Exhibit 6-1**.

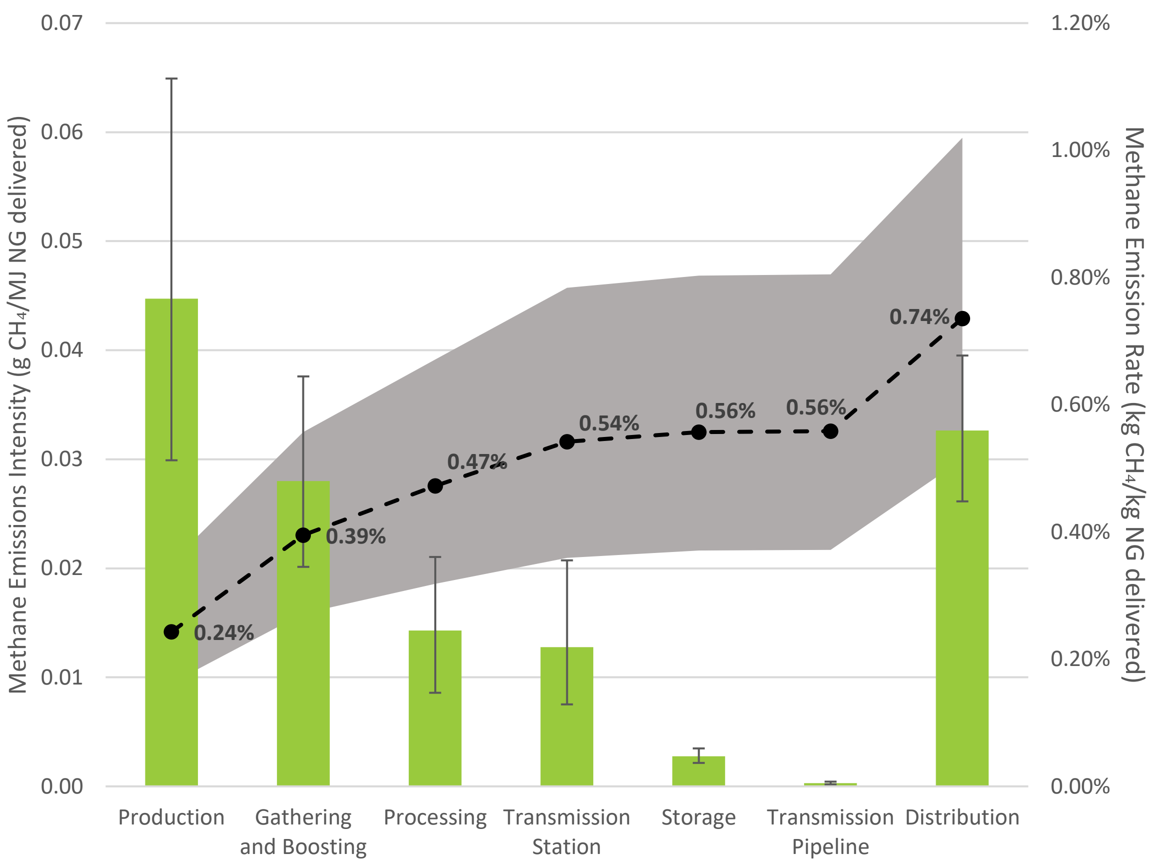
Exhibit 6-1. Life cycle GHG emissions intensity for the 2020 U.S. average NG supply chain, "production through distribution" life cycle boundary, g CO_2e/MJ (IPCC AR6, 100-year GWP, HHV basis)



The error bars in **Exhibit 6-1** (and all other emission results shown in this analysis) represent the 95 percent confidence interval for the average value. This wide confidence interval is an indication of the high variability in the underlying data. As discussed in **Section 5,** the data for NG systems are scattered and skewed.

For the "production through distribution" life cycle boundary, the national average CH_4 emission rate is 0.74 percent, with a 95 percent mean confidence interval ranging 0.51–1.02 percent. For the "production through transmission network" life cycle boundary, the national average CH_4 emission rate is 0.56 percent, with a 95 percent mean confidence interval ranging 0.37–0.80 percent. This emission rate represents CH_4 emissions released to air (via venting, fugitives, combustion, or other sources) per unit of NG delivered to end users. The CH_4 emissions for the U.S. NG supply chain are shown in **Exhibit 6-2**.

Exhibit 6-2. Life cycle CH_4 emissions intensity for the 2020 U.S. average NG supply chain, "production through distribution" life cycle boundary, g CO_2e/MJ (IPCC AR6, 100-year GWP, HHV basis)

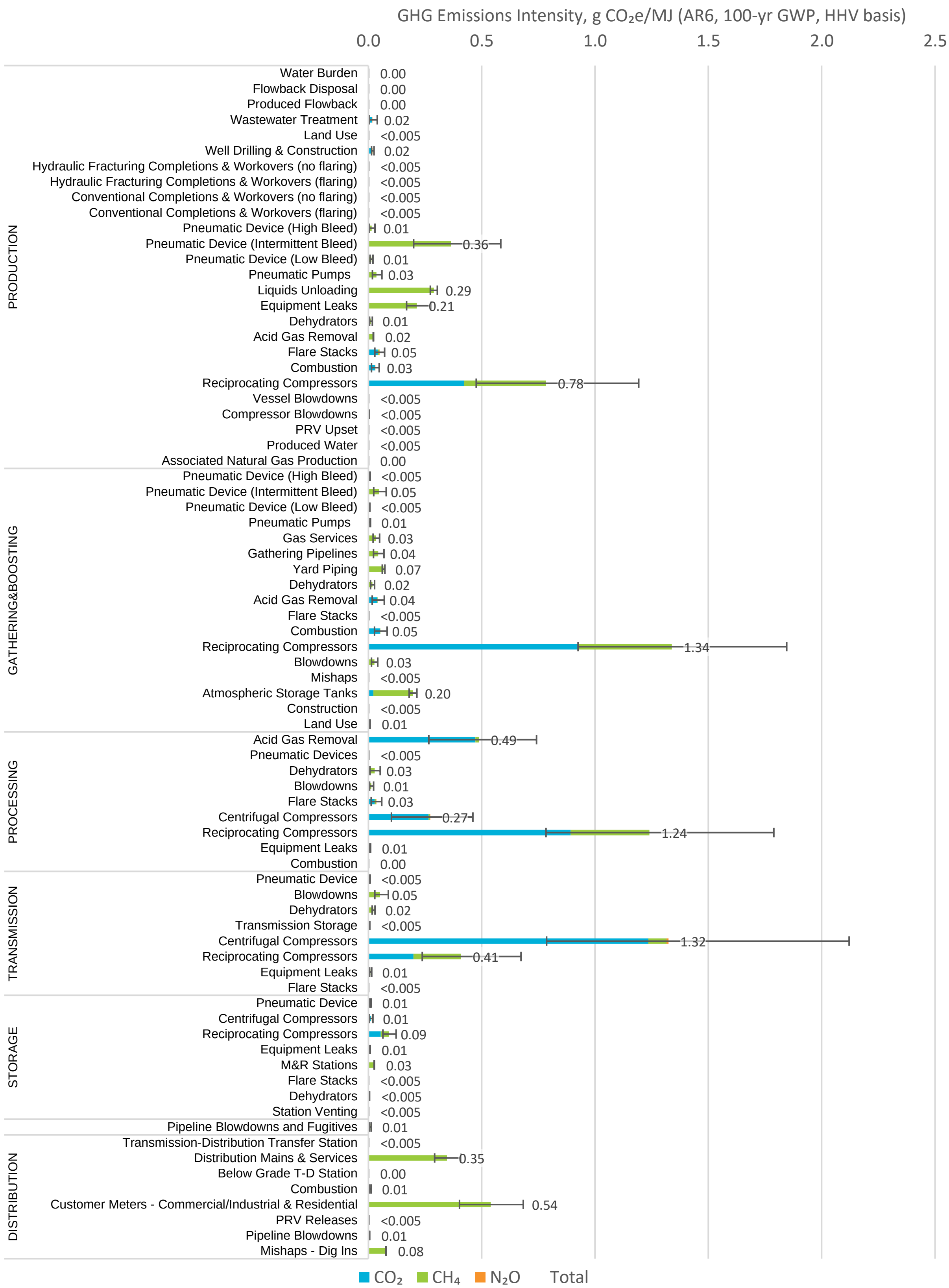


The GHG contributions from specific source categories are shown in **Exhibit 6-3**. The top contributors to CO_2 and CH_4 emissions are combustion exhaust and other venting from compressor systems. Compressor systems are prevalent in all supply chain stages, so compressor emissions are key emission drivers in all supply chain stages. Other top contributors to CH_4 emissions are as follows:

- Intermittent-bleed pneumatic devices (production stage)
- Equipment leaks (production stage)
- Liquids unloading (production stage)
- Distribution mains and services (distribution stage)
- Customer meters (distribution stage)

Detailed graphs for all onshore NG scenarios are provided in **Appendix E** (available in the release package published along with this report)**.**

Exhibit 6-3. Detailed GHG emission sources for the 2020 U.S. average NG supply chain, "production through distribution" life cycle boundary, g CO_2e/MJ (IPCC AR6, 100-year GWP, HHV basis)



Using the percent of gas estimated to flow through the transmission network to end users and of gas that flows through the distribution network to end users, and using the "production through distribution" and "production through transmission network" life cycle boundary results, an NG consumption-weighted national average profile was estimated. The proportion of total NG that passes through the transmission network for consumption by consumers (mainly industrial and power-generation sectors) was estimated as 46 percent, and gas that passes through distribution for consumption by consumers (mainly residential and commercial, but also including volumes delivered to industrial and power-generation sectors) was estimated as 54 percent (as discussed in **Exhibit 4-10**). The NG consumption-weighted national average GHG emissions intensity is 8.3 g CO_2e/MJ (with a mean confidence interval of 5.3–12.2 g CO_2e/MJ, AR6 100-yr GWP basis), and the CH_4 emissions rate is 0.65 percent, with a 95 percent confidence interval ranging 0.45–0.92 percent.

The CH_4 emission rates for all scenarios (27 onshore and 2 offshore) are sorted in descending order of mean CH_4 emission rate for the "production through distribution" life cycle boundary in **Exhibit 6-4**. The average CH_4 emission rates from these scenarios range 0.48–4.00 percent for the "production through distribution" life cycle boundary and 0.29–3.80 percent for the "production through transmission network" life cycle boundary.

Exhibit 6-4. Life cycle CH_4 emission rates for NG scenarios with U.S. average transmission and distribution stages (kg CH_4/kg NG delivered)

Techno-basin	CH_4 Emission Rate					
	Production through Transmission Network Boundary			Production through Distribution Boundary		
	p2.5	Mean	p97.5	p2.5	Mean	p97.5
Uinta – conv	3.25%	3.80%	4.48%	3.41%	4.00%	4.72%
San Juan – shale	1.24%	1.78%	2.40%	1.40%	1.97%	2.63%
Arkoma – conv	1.09%	1.55%	2.20%	1.24%	1.74%	2.43%
San Juan – CBM	0.80%	1.53%	2.64%	0.96%	1.72%	2.88%
Anadarko – conv	0.84%	1.40%	2.20%	0.97%	1.58%	2.43%
Uinta – tight	0.61%	1.19%	2.06%	0.77%	1.38%	2.30%
Arkoma – shale	0.62%	1.01%	1.52%	0.78%	1.20%	1.75%
Strawn – shale	0.66%	0.99%	1.43%	0.80%	1.17%	1.66%
Anadarko – tight	0.57%	0.95%	1.46%	0.72%	1.13%	1.68%
Arkla – tight	0.52%	0.91%	1.42%	0.67%	1.09%	1.65%
Fort Worth – shale	0.57%	0.91%	1.38%	0.71%	1.08%	1.59%
Gulf – tight	0.40%	0.72%	1.17%	0.56%	0.91%	1.40%
Gulf – conv	0.45%	0.69%	1.00%	0.59%	0.86%	1.21%
Piceance – tight	0.37%	0.67%	1.05%	0.52%	0.85%	1.27%
Anadarko – shale	0.43%	0.65%	0.94%	0.57%	0.83%	1.16%
Permian – shale	0.41%	0.65%	0.95%	0.56%	0.83%	1.17%
Gulf – shale	0.36%	0.59%	0.89%	0.51%	0.78%	1.13%

Techno-basin	CH₄ Emission Rate					
	Production through Transmission Network Boundary			Production through Distribution Boundary		
	p2.5	Mean	p97.5	p2.5	Mean	p97.5
East Texas – shale	0.45%	0.59%	0.77%	0.60%	0.78%	0.99%
South Oklahoma – shale	0.36%	0.57%	0.83%	0.51%	0.75%	1.05%
East Texas – tight	0.34%	0.52%	0.76%	0.49%	0.71%	0.98%
Permian – conv	0.38%	0.53%	0.73%	0.52%	0.70%	0.94%
East Texas – conv	0.32%	0.50%	0.74%	0.47%	0.69%	0.96%
Green River – tight	0.24%	0.46%	0.74%	0.39%	0.65%	0.97%
Green River – conv	0.31%	0.46%	0.65%	0.46%	0.65%	0.88%
Alaska – offshore	0.30%	0.40%	0.53%	0.45%	0.59%	0.75%
Appalachian – shale	0.30%	0.40%	0.54%	0.43%	0.58%	0.75%
Arkla – shale	0.24%	0.35%	0.50%	0.39%	0.54%	0.72%
Arkla – conv	0.21%	0.35%	0.52%	0.36%	0.53%	0.74%
GoM – offshore	0.22%	0.29%	0.38%	0.37%	0.48%	0.60%

Exhibit 6-5 shows the emission rates with each basin technology weighted by its relative production share. Appalachian shale and Permian conventional account for the largest production shares and thus account for the greatest contributions to the average national emission rate. These emission rates are additive; they sum to the same national average emission rate. For the "production through distribution" life cycle boundary, the production-weighted national average CH_4 emission rate is 0.74 percent, with a 95 percent confidence interval for the mean ranging 0.51–1.02 percent, and for the "production through transmission network" life cycle boundary, the production-weighted national average CH_4 emission rate is 0.56 percent, with a 95 percent confidence interval for the mean ranging 0.37–0.80 percent.

Exhibit 6-5. Production-weighted life cycle CH_4 emission rates for NG scenarios with U.S. average transmission and distribution stages (kg CH_4/kg NG delivered)

Techno-basin	CH₄ Emission Rate					
	Production through Transmission Network Boundary			Production through Distribution Boundary		
	p2.5	Mean	p97.5	p2.5	Mean	p97.5
Appalachian – shale	0.11%	0.16%	0.21%	0.17%	0.22%	0.29%
Permian – conv	0.04%	0.05%	0.07%	0.05%	0.07%	0.09%
Permian – shale	0.03%	0.05%	0.07%	0.04%	0.06%	0.08%
Arkla – shale	0.01%	0.02%	0.03%	0.02%	0.03%	0.04%
Anadarko – conv	0.02%	0.03%	0.04%	0.02%	0.03%	0.04%
Gulf – shale	0.01%	0.02%	0.03%	0.02%	0.03%	0.04%
East Texas – tight	0.01%	0.02%	0.03%	0.02%	0.03%	0.04%

Techno-basin	CH_4 Emission Rate					
	Production through Transmission Network Boundary			Production through Distribution Boundary		
	p2.5	Mean	p97.5	p2.5	Mean	p97.5
Gulf – conv	0.01%	0.02%	0.03%	0.02%	0.02%	0.03%
Anadarko – shale	0.01%	0.02%	0.02%	0.02%	0.02%	0.03%
Anadarko – tight	0.01%	0.02%	0.03%	0.01%	0.02%	0.03%
San Juan – shale	0.01%	0.02%	0.03%	0.02%	0.02%	0.03%
Arkoma – shale	0.01%	0.02%	0.03%	0.01%	0.02%	0.03%
Strawn – shale	0.01%	0.02%	0.02%	0.01%	0.02%	0.03%
Arkla – conv	0.01%	0.01%	0.02%	0.01%	0.02%	0.02%
Green River – tight	0.01%	0.01%	0.02%	0.01%	0.02%	0.03%
San Juan – CBM	0.01%	0.01%	0.02%	0.01%	0.02%	0.03%
Piceance – tight	0.01%	0.01%	0.02%	0.01%	0.02%	0.02%
GoM – offshore	0.01%	0.01%	0.01%	0.01%	0.01%	0.02%
Arkla – tight	0.00%	0.01%	0.01%	0.01%	0.01%	0.01%
Arkoma – conv	0.01%	0.01%	0.01%	0.01%	0.01%	0.01%
Fort Worth – shale	0.005%	0.008%	0.012%	0.006%	0.010%	0.014%
Uinta – tight	0.004%	0.007%	0.012%	0.005%	0.008%	0.014%
South Oklahoma – shale	0.003%	0.005%	0.008%	0.005%	0.007%	0.010%
Gulf – tight	0.003%	0.006%	0.009%	0.004%	0.007%	0.011%
East Texas – conv	0.003%	0.004%	0.006%	0.004%	0.006%	0.008%
East Texas – shale	0.003%	0.004%	0.005%	0.004%	0.005%	0.007%
Uinta – conv	0.001%	0.001%	0.001%	0.001%	0.001%	0.001%
Alaska – offshore	0.0004%	0.0006%	0.0007%	0.0006%	0.001%	0.001%
Green River – conv	0.0002%	0.0003%	0.0004%	0.0003%	0.0004%	0.0005%
National Average	**0.37%**	**0.56%**	**0.80%**	**0.51%**	**0.74%**	**1.02%**

Note: All basins are arranged in descending order of mean production-weighted CH_4 emission rate for the "production through distribution" life cycle boundary.

Exhibit 6-6 and **Exhibit 6-7** show the life cycle GHG results using IPCC AR6 100- and 20-year GWPs, respectively. CO_2 and CH_4 emission rates vary across scenarios, but a comparison of the two exhibits demonstrates the importance of CH_4 intensity. On a 100-year timeframe, summary statistics of model results indicate that the highest scenario (Uinta – conv) is about 4.9 times higher than the lowest scenario (GoM – offshore) for the U.S. average delivery pathway. On a 20-year timeframe, the highest and lowest scenarios differ by a factor of 7.5.

Exhibit 6-6. Life cycle GHG emissions for NG scenarios with U.S. average transmission through distribution stages (IPCC AR6, 100-year GWP, HHV basis)

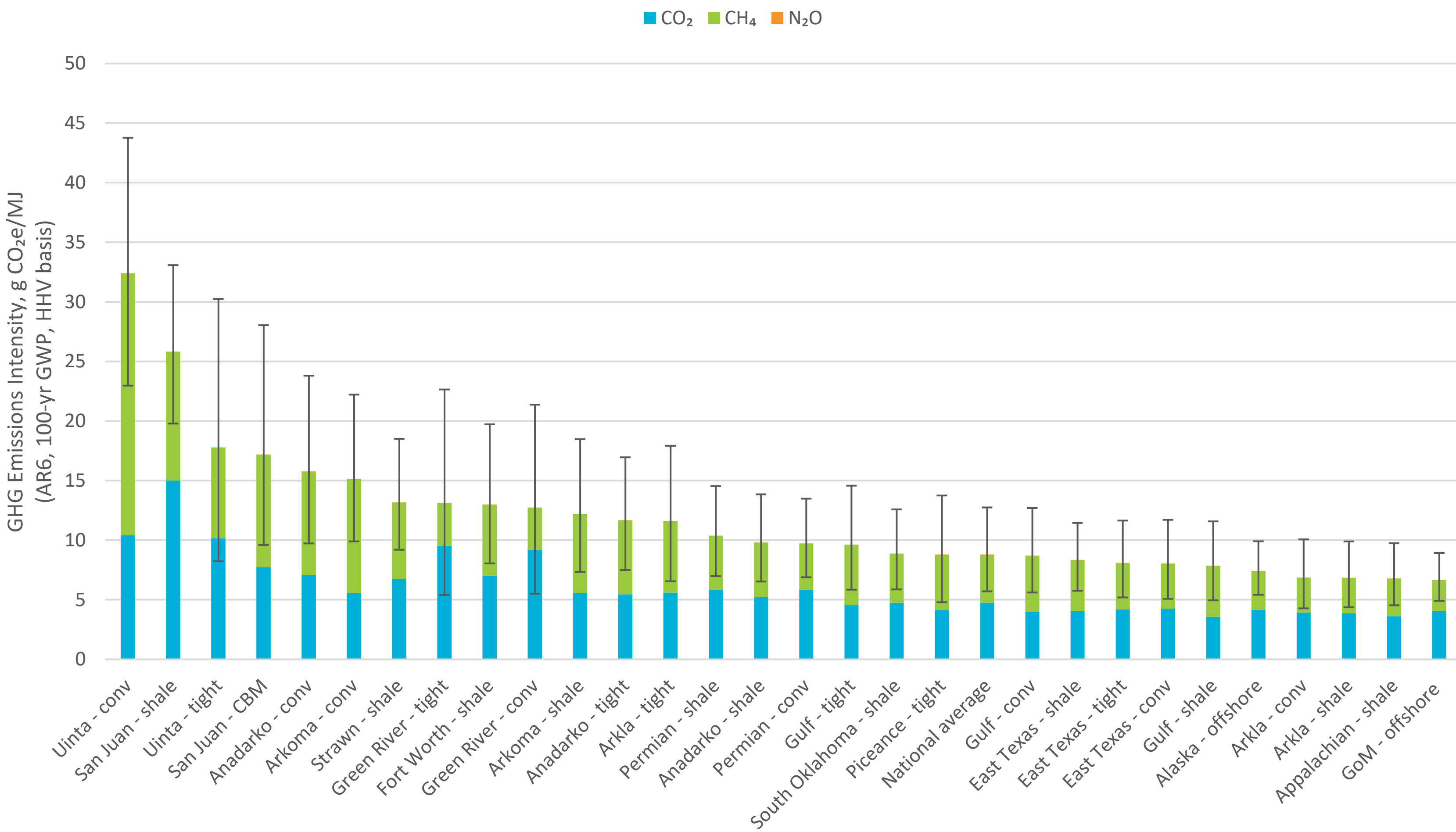


Exhibit 6-7. Life cycle GHG emissions for NG scenarios with U.S. average transmission through distribution stages (IPCC AR6, 20-year GWP, HHV basis)

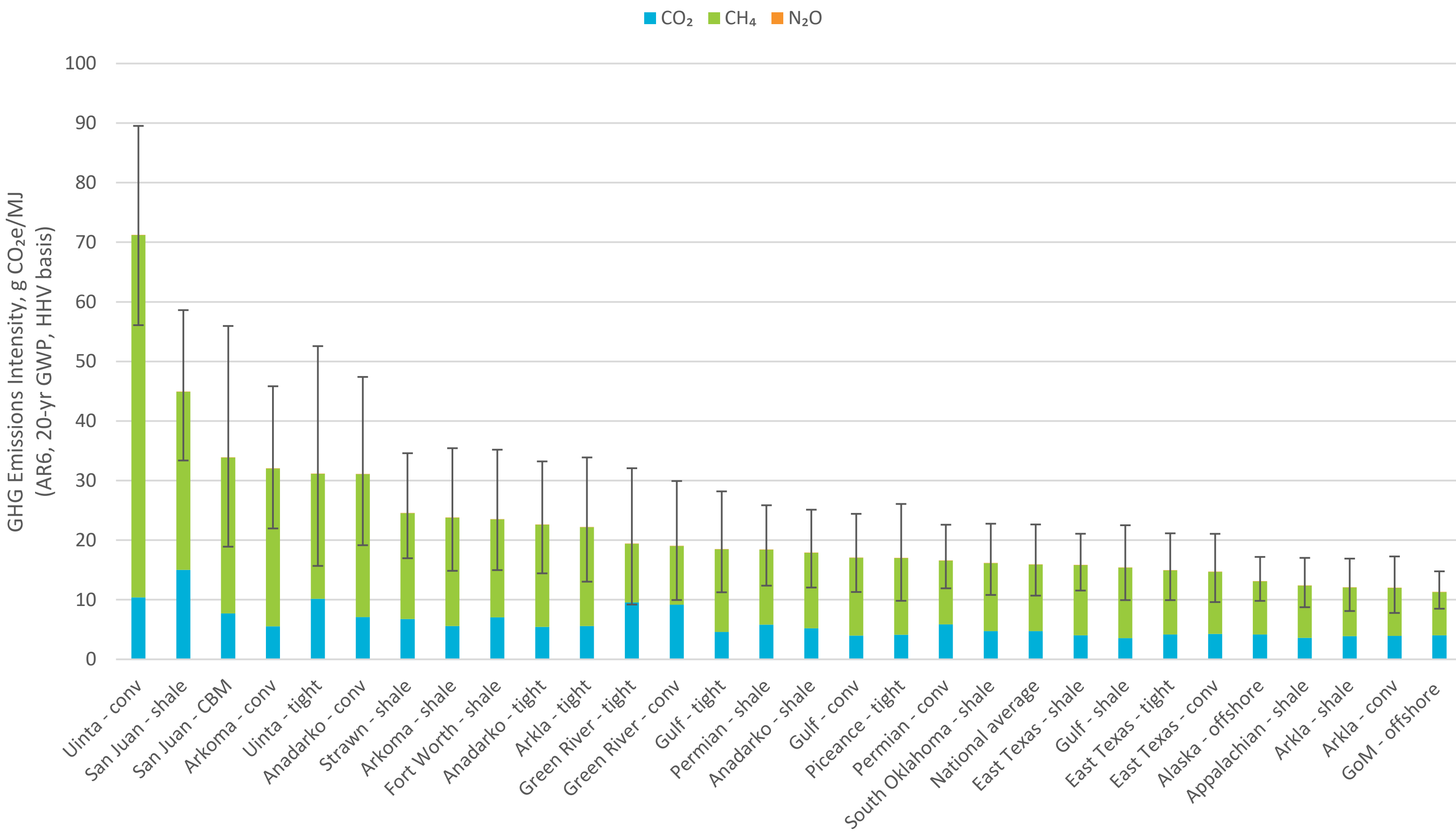


Exhibit 6-8 ranks the uncertainty results for specific emission sources for the U.S. NG supply chain. Compressor emissions are the top sources of uncertainty, as well as AGR both at processing and at gathering and boosting facilities, intermittent-bleed pneumatic device venting at production sites, both customer meters and mains and services at distribution, equipment leaks at production sites, transmission equipment blowdowns, and combustion emissions at gathering and boosting facilities. In this exhibit, the high end represents the difference between the simulated 97.5th percentile and expected emissions intensities, and the low end represents the difference between the simulated expected and 2.5th percentile emissions intensities for the various categories.

Exhibit 6-8. Ranking of GHG emissions intensity uncertainty for the U.S. NG supply chain, "production through distribution" life cycle boundary

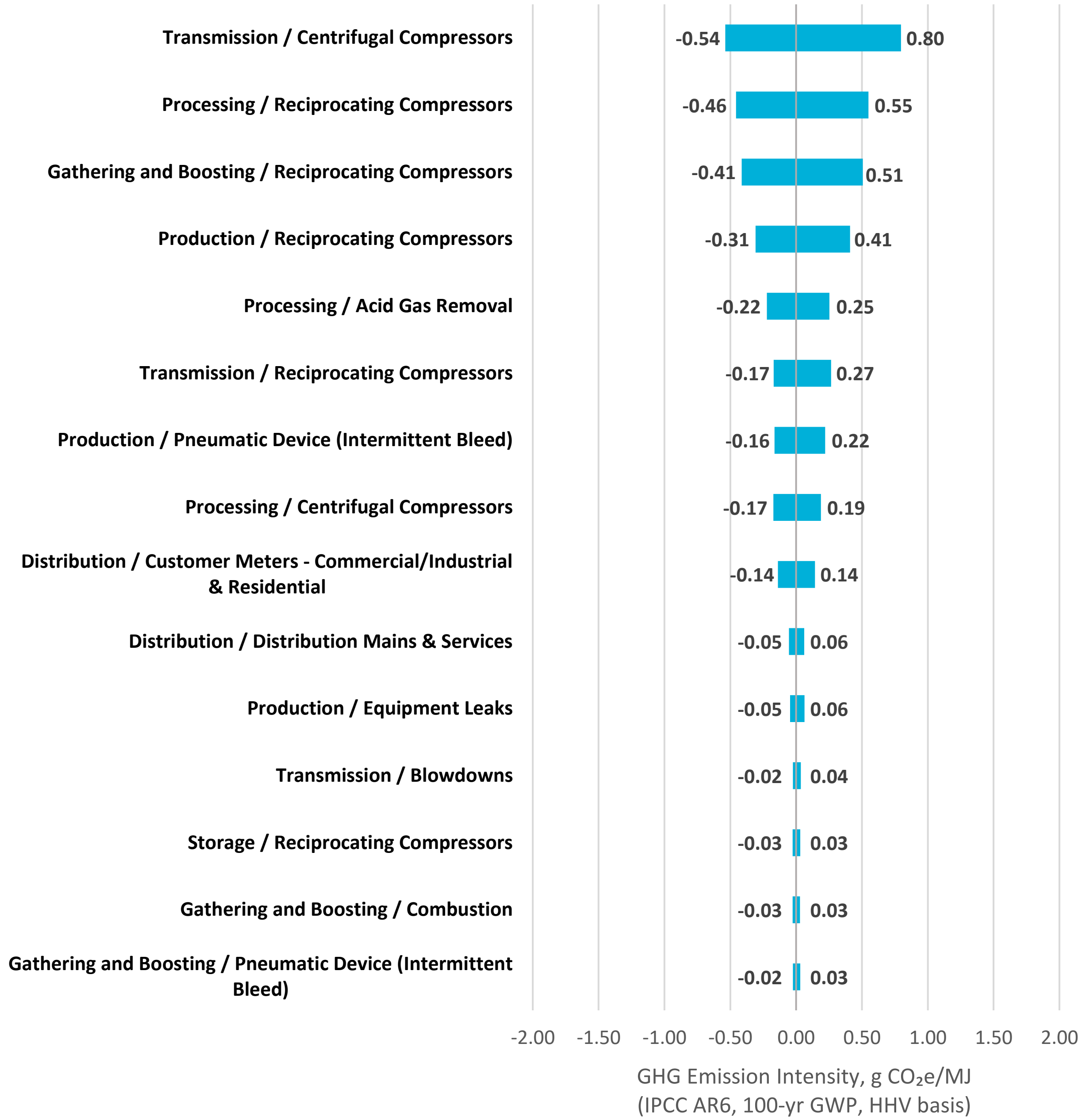
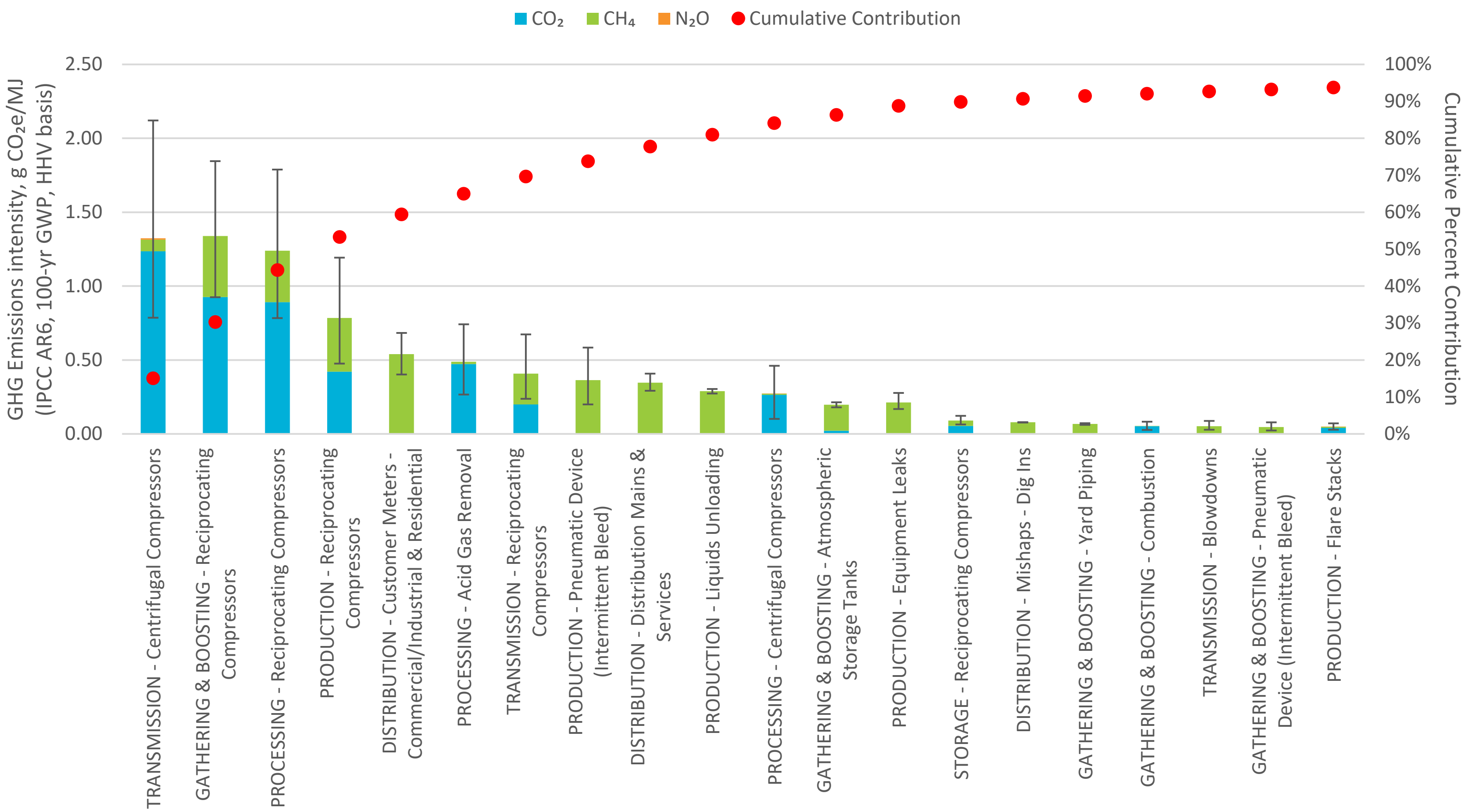


Exhibit 6-9 provides a magnified view of the top 20 emission categories covered in **Exhibit 6-3** and highlights the contribution of these emission categories (93.4 percent of total emissions) to the national average GHG emission intensity for the "production through distribution" life cycle boundary. Compressor emissions dominate the overall U.S. average GHG emissions profile, and other key emission categories include pneumatic devices, blowdowns, equipment leaks, flaring, and distribution mains and mishaps. These emission sources present a crucial opportunity for decarbonizing the NG supply chain and streamlining investment in the most effective emissions mitigation technologies.

Exhibit 6-9. Cumulative contribution impact of the top 20 emission categories on GHG emissions intensity of the U.S. average NG supply chain, "production through distribution" life cycle boundary (IPCC AR6, 100-year GWP, HHV basis)



6.2 Regionalized Greenhouse Gas Emissions

The regionalized results assessing the life cycle GHG emissions intensity of NG produced in various basins and delivered to different regions are discussed in detail here. The comparisons by techno-basin and region reflect summary statistics of Monte Carlo results. As such, both the means and uncertainty ranges should be considered in assessing the significance of any comparison.

Exhibit 6-10 and **Exhibit 6-11** provide the expected GHG emissions intensity life cycle results for all the feasible regional scenarios analyzed in this study on a "production through distribution" and "production through transmission network" life cycle boundary, respectively. All scenarios assessed to be unfeasible based on work by Littlefield et al. [67], such as Appalachian shale gas delivered to the Pacific region, are marked as "-." The p2.5 and p97.5 GHG emissions intensity values of the mean are reported in **Appendix E** (available in the release package provided along with this report).

Exhibit 6-10. Expected GHG emissions intensity of regional scenarios, "production through distribution" life cycle boundary, g CO_2e/MJ (IPCC AR6, 100-year GWP, HHV basis)

		Downstream Regions					
Upstream Scenarios	Techno-basin	Pacific	Rocky Mountain	Southwest	Southeast	Midwest	Northeast
	Appalachian – shale	-	-	-	6.93	5.91	6.10
	Gulf – conv	-	-	8.21	12.22	10.63	14.00
	Gulf – shale	-	-	7.42	11.62	9.88	13.31
	Gulf – tight	-	-	9.17	13.42	11.67	15.17
	Arkla – conv	-	-	-	6.17	-	-
	Arkla – shale	-	-	-	6.16	-	-
	Arkla – tight	-	-	-	10.84	-	-
	East Texas – conv	-	-	7.59	11.72	10.04	13.43
	East Texas – shale	-	-	7.87	12.03	10.33	13.73
	East Texas – tight	-	-	7.63	11.76	10.08	13.48
	Arkoma – conv	-	-	14.60	19.04	17.26	20.97
	Arkoma – shale	-	-	11.68	16.04	14.26	17.85
	South Oklahoma – shale	-	-	8.40	12.55	10.85	14.25
	Anadarko – conv	-	-	15.20	15.76	17.86	21.57
	Anadarko – shale	-	-	9.32	9.80	11.80	15.25
	Anadarko – tight	-	-	11.15	11.66	13.69	17.21
	Strawn – shale	-	-	12.68	13.18	15.21	18.82
	Fort Worth – shale	-	-	12.47	12.99	15.02	18.60
	Permian – conv	-	-	9.25	9.73	11.73	15.21
	Permian – shale	-	-	9.90	10.38	12.38	15.84
	Green River – conv	12.74	13.08	14.32	-	14.05	-
	Green River – tight	13.15	13.50	14.74	-	14.47	-
	Uinta – conv	32.39	32.54	34.15	-	33.91	-
	Uinta – tight	17.77	18.08	19.51	-	19.24	-
	San Juan – CBM	-	-	16.65	17.18	19.40	23.19
	San Juan – Shale	-	-	25.22	25.82	28.14	32.32
	Piceance – tight	9.12	9.12	10.32	-	10.08	
	Alaska offshore	7.15	-	-	-	-	-
	GoM offshore	-	-	-	6.68	-	-

Exhibit 6-11. Expected GHG emissions intensity of regional scenarios, "production through transmission network" life cycle boundary, g CO_2e/MJ (IPCC AR6, 100-year GWP, HHV basis)

		Downstream Regions					
	Techno-basin	**Pacific**	**Rocky Mountain**	**Southwest**	**Southeast**	**Midwest**	**Northeast**
Upstream Scenarios	Appalachian – shale	-	-	-	5.68	4.86	5.07
	Gulf – conv	-	-	7.19	10.97	9.57	12.95
	Gulf – shale	-	-	6.27	10.20	8.69	12.13
	Gulf – tight	-	-	8.02	11.99	10.48	13.99
	Arkla – conv	-	-	-	4.82	-	-
	Arkla – shale	-	-	-	4.81	-	-
	Arkla – tight	-	-	-	9.47	-	-
	East Texas – conv	-	-	6.49	10.35	8.89	12.30
	East Texas – shale	-	-	6.77	10.64	9.18	12.60
	East Texas – tight	-	-	6.53	10.40	8.94	12.35
	Arkoma – conv	-	-	13.46	17.57	16.06	19.79
	Arkoma – shale	-	-	10.54	14.57	13.07	16.67
	South Oklahoma – shale	-	-	7.33	11.17	9.73	13.15
	Anadarko – conv	-	-	14.12	14.75	16.72	20.46
	Anadarko – shale	-	-	8.25	8.80	10.69	14.15
	Anadarko – tight	-	-	10.08	10.66	12.57	16.12
	Strawn – shale	-	-	11.61	12.17	14.11	17.72
	Fort Worth – shale	-	-	11.41	12.00	13.92	17.51
	Permian – conv	-	-	8.19	8.74	10.63	14.12
	Permian – shale	-	-	8.84	9.38	11.27	14.75
	Green River – conv	12.28	10.46	13.17	-	12.87	-
	Green River – tight	12.62	10.86	13.59	-	13.29	-
	Uinta – conv	32.02	29.82	32.95	-	32.67	-
	Uinta – tight	17.34	15.48	18.35	-	18.04	-
	San Juan – CBM	-	-	15.50	16.10	18.17	22.00
	San Juan – Shale	-	-	24.05	24.72	26.92	31.11
	Piceance – tight	8.32	6.64	9.24	-	8.94	-
	Alaska offshore	6.34	-	-	-	-	-
	GoM offshore	-	-	-	5.64	-	-

Exhibit 6-12 shows the variation in GHG emissions intensity of NG delivered to different regions for the "production through distribution" life cycle boundary. The Rocky Mountain region has the highest expected "production through distribution"-stage emissions intensity (12.5 g CO_2e/MJ) and the Northeast has the lowest (7.3 g CO_2e/MJ). All six regional scenarios depict wide variability in emissions intensity, with significant overlap of the mean confidence intervals. **Exhibit 6-13**, **Exhibit 6-14**, and **Exhibit 6-15** compare the regional GHG emissions intensity of NG delivered to various regions, speciated by basin and extraction technology, giving a closer look at all conventional, shale, and tight basins, respectively. The results highlight the variation in NG emissions profiles across different basins and across different regions receiving gas produced from the same basin. These differences in GHG intensity of NG delivered to various regions from

a production basin reflect the contrasting processing stage operations and transmission and distribution networks across different regions. Additionally, the variable distance covered by NG in transmission pipelines to reach end users in different regions is another important driver for regional emissions profiles.

Exhibit 6-12. GHG emissions intensity for six regional delivery scenarios from all production basins, "production through distribution" life cycle boundary, g CO_2e/MJ (IPCC AR6, 100-year GWP, HHV basis)

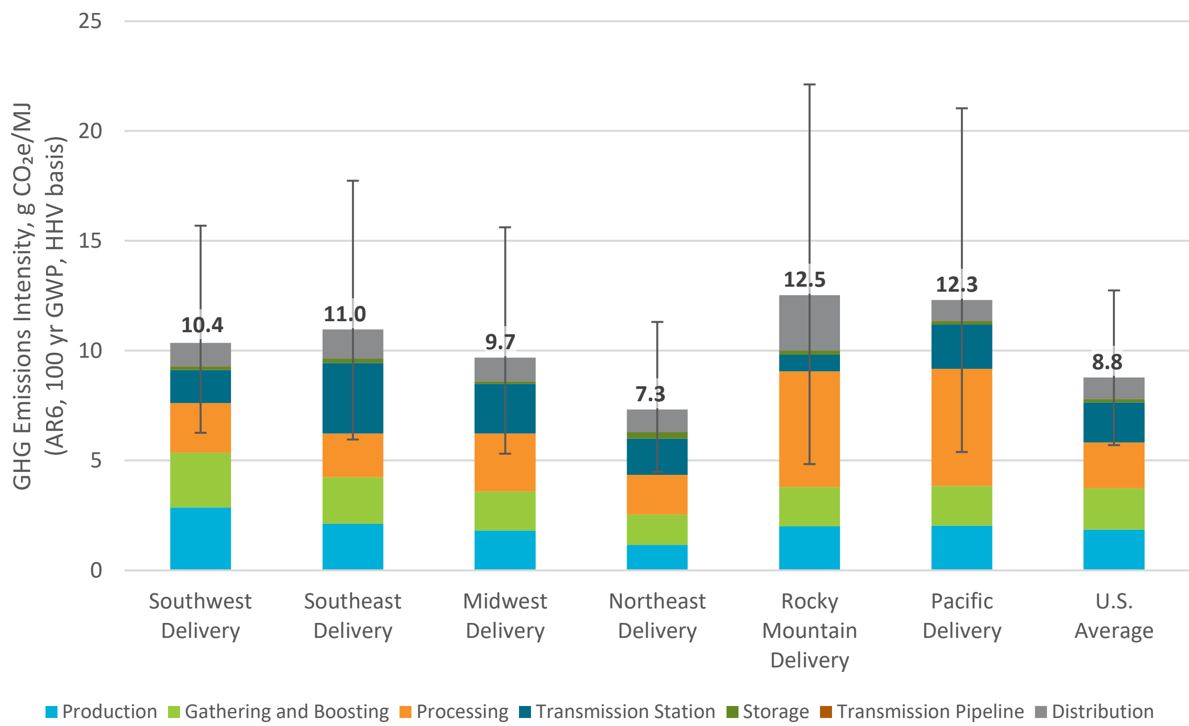


Exhibit 6-13. Regional GHG emissions intensity of gas delivered from conventional basins, "production through distribution" life cycle boundary, g CO_2e/MJ (IPCC AR6, 100-year GWP, HHV basis)

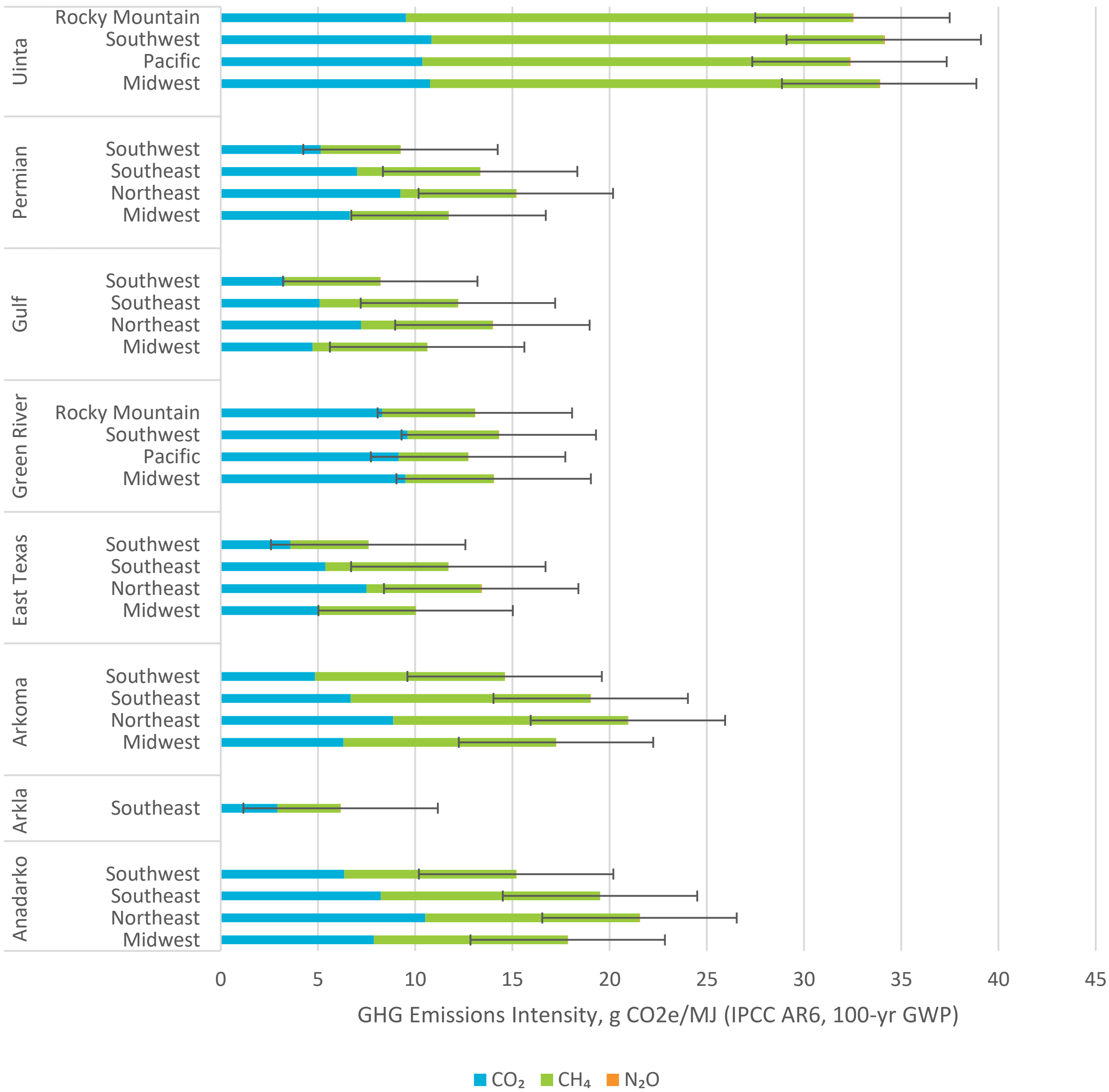


Exhibit 6-14. Regional GHG emissions intensity of gas delivered from shale gas basins, "production through distribution" life cycle boundary, g CO_2e/MJ (IPCC AR6, 100-year GWP, HHV basis)

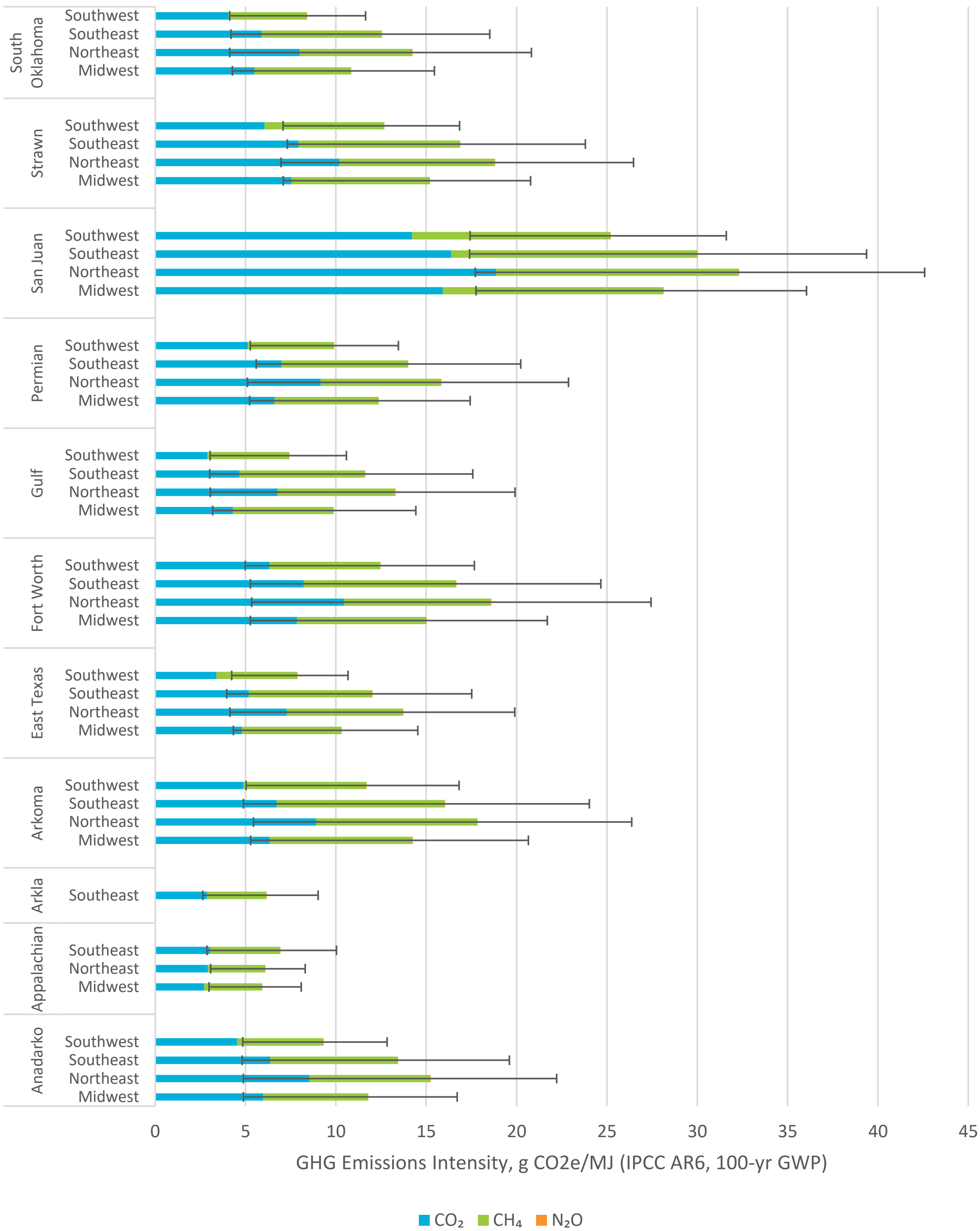
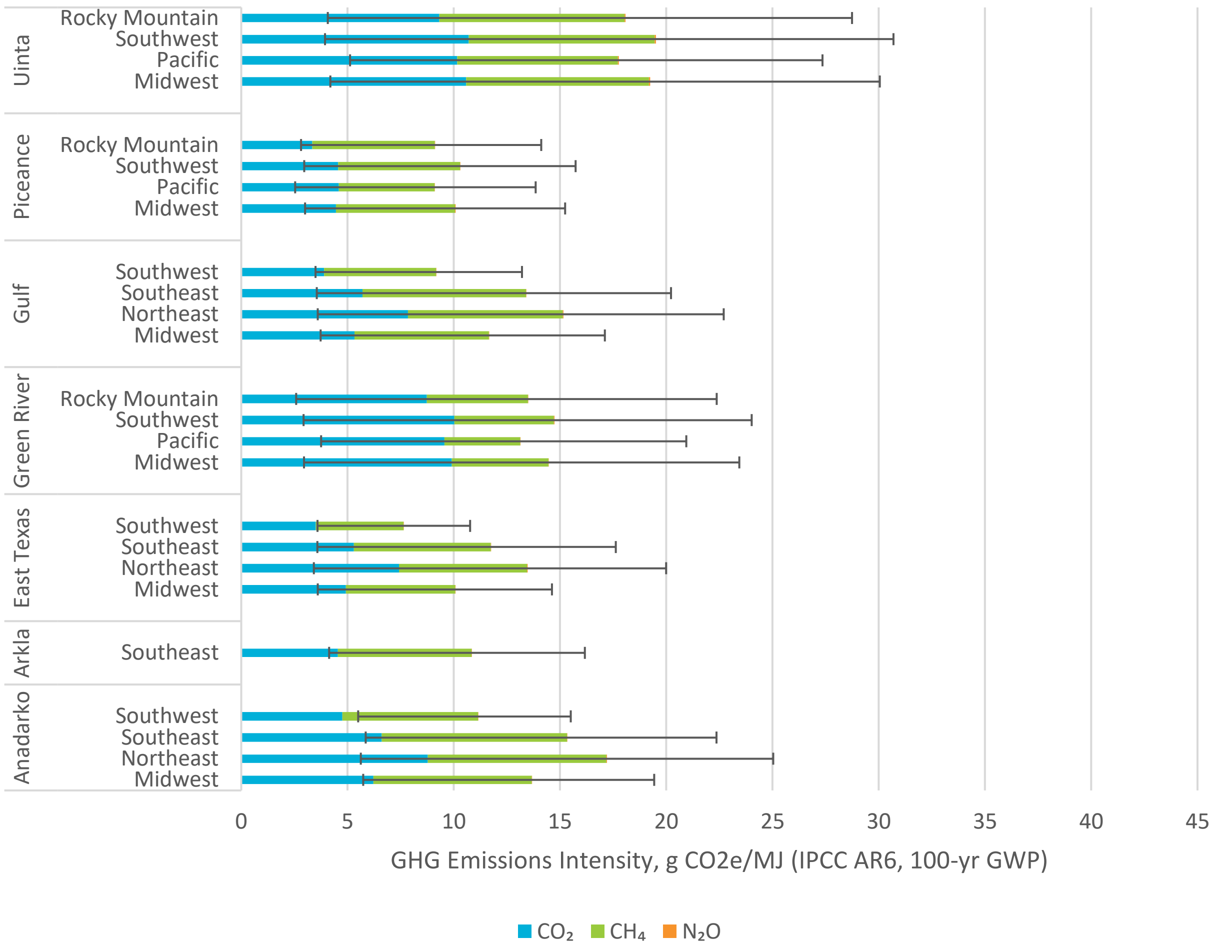


Exhibit 6-15. Regional GHG emissions intensity of gas delivered from tight gas basins, "production through distribution" life cycle boundary, g CO_2e/MJ (IPCC AR6, 100-year GWP, HHV basis)

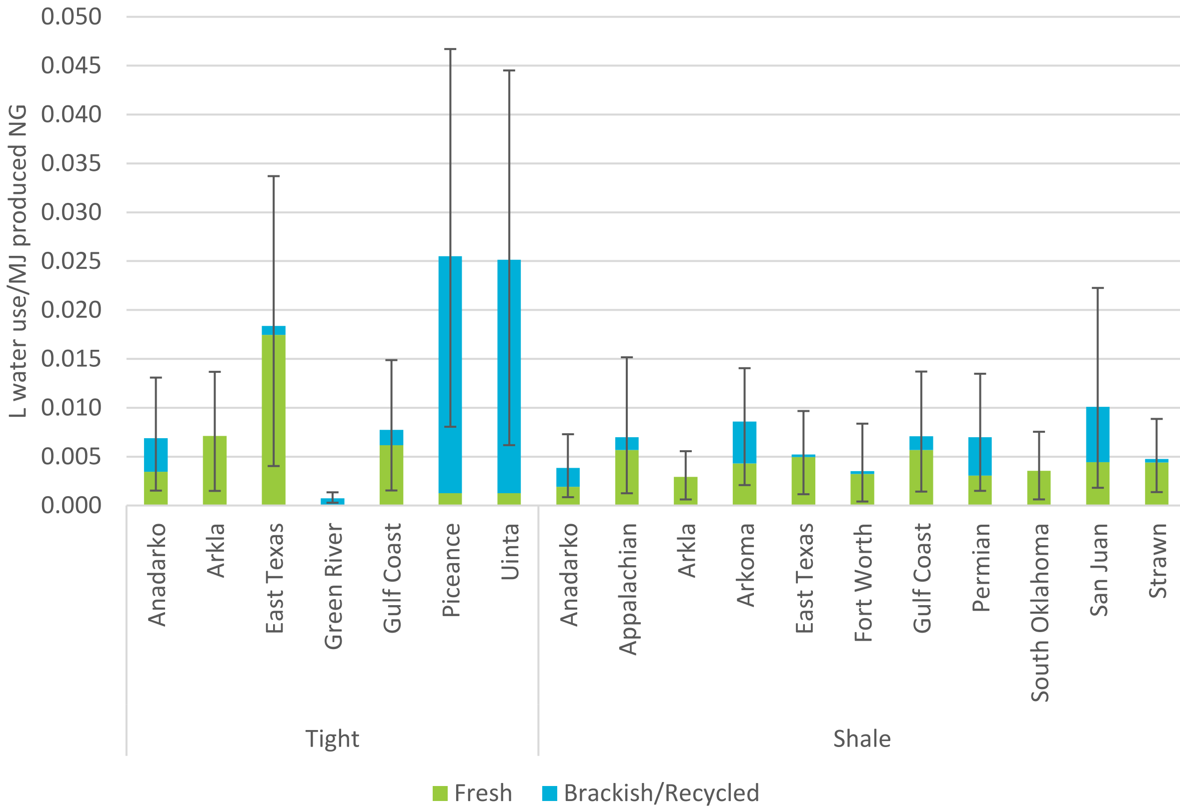


For the "production through distribution" life cycle boundary, upon consideration of all 14 onshore gas production basins covered in this study, the Uinta – conv scenario with gas delivered to the Southwest region (34.2 g CO_2e/MJ, with a 95 percent confidence interval ranging 23.1—48.1 g CO_2e/MJ, IPCC AR6 100-year GWP) has the highest GHG emissions intensity. On the contrary, the Appalachian – shale scenario with gas delivered to the Midwest region (5.9 g CO_2e/MJ, with a 95 percent confidence interval ranging 3.7–8.8 g CO_2e/MJ, IPCC AR6 100-year GWP) has the lowest GHG emissions intensity.

6.3 Water Use and Emissions

The results of upstream water impacts can be categorized into two main sections: stimulation water volume, and flowback and produced water volumes. **Exhibit 6-16** details the results of stimulation water volume for tight and shale wells. Conventional and CBM wells are not included as they are not considered to be hydraulically fractured. The results are categorized by techno-basin (a combination of a production technology and location) and are shown in liters of water per MJ of produced NG. Error bars represent the 95 percent confidence interval, here and throughout this results section. The blue bars represent water use that sources fresh water, while the green bars represent water sourced from brackish or recycled reserves. The sum of the two represents the total water use intensity.

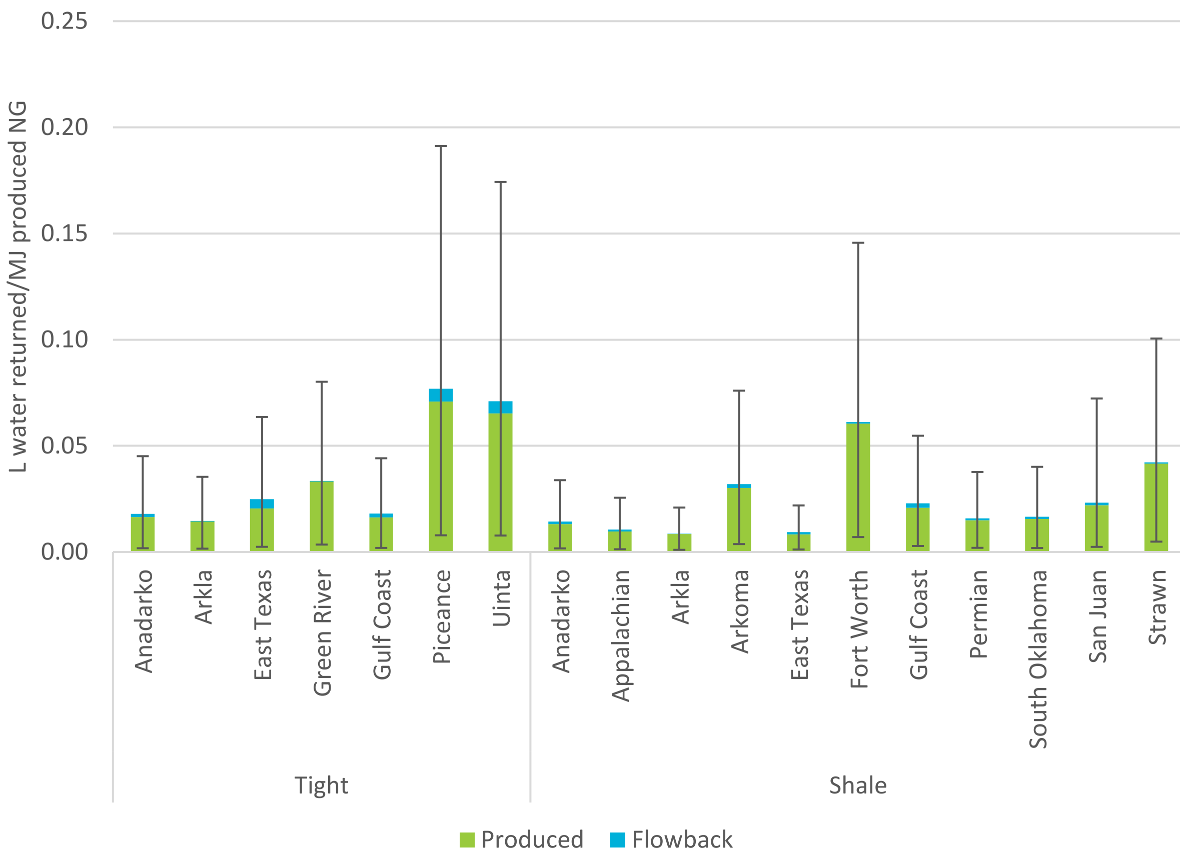
Exhibit 6-16. Stimulation volume intensity to hydraulically fractured shale and tight wells



These results are driven by two main parameters: total volume of water used to fracture a well and EUR per well. The EUR is used to transform the total water use to the functional unit. Thus, variability in either value will influence the resulting water use. A well with a large total water volume per well may not necessarily have a large water burden if the well also has a large EUR. Here, Piceance – tight has the highest expected value for total water use at approximately 2.55E-02 L/MJ. East Texas – tight has the highest freshwater volume at 1.75E-02 L/MJ. Green River – tight has the lowest total water burden at 7.51E-04 L/MJ. There is variability among all results, with no clear trend dividing tight and shale results.

Exhibit 6-17 details the results for flowback and produced water volume intensity and displays both flowback and produced water volumes for tight and shale wells, which return both types of water. The green bars represent the flowback portion, and the blue bars represent the produced water portion, with the sum of the two representing the total volume returned in liters of water per MJ of produced NG. The scenarios are organized by techno-basins.

Exhibit 6-17. Intensity of flowback and produced water for shale and tight scenarios



These results demonstrate that while flowback water volume may be large early in the well's life, when normalized over the lifetime of the well, it is much less than produced water. The flowback water is calculated as a function of stimulation water, taken as a percent, and then transformed to the functional unit using EUR. Thus, many factors influence the resulting volume of flowback water. Produced water is calculated from a distribution of average daily produced water volumes and transformed to the functional unit with EUR. The results are highly variable due to the high variability in produced water volumes, for which there was insufficient data to inform more confident parameters. Among tight and shale scenarios, the Piceance – tight techno-basin had the highest produced water volume at 7.09E-02 L/MJ, as well as the highest total water volume returned at 7.70E-02 L/MJ. The full inventory results for all scenarios can be found in **Appendix F** (available in the release package published along with this report).

6.4 Effect of Marginal Wells on the National Average Emissions Intensity Profile

As noted in **Section 2.3**, the methane emissions intensity of marginal well production (i.e., wells with an average production of less than 15 boe/day) is significantly higher than for non-marginal counterparts [13], and proper accounting of these emissions is required to improve the accuracy of petroleum and NG supply chain GHG inventory estimates. **Exhibit 6-18** highlights the observed variation in the production-stage GHG emissions intensity upon accounting for methane emissions intensity of marginal wells (assuming both a 5.5 percent and 8 percent production share, based on recent literature [13, 14]).

Exhibit 6-18. 2020 U.S. average production-stage GHG emissions intensity, including methane emissions from marginal wells

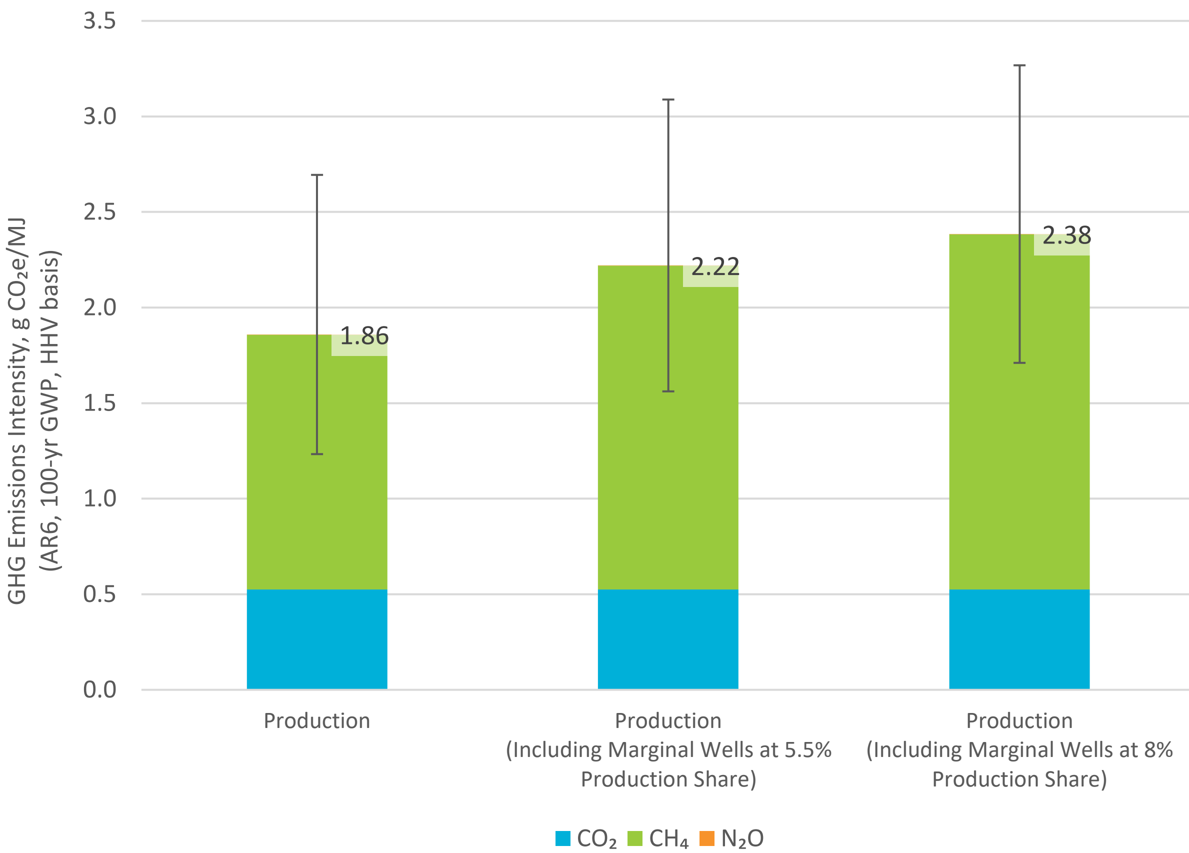
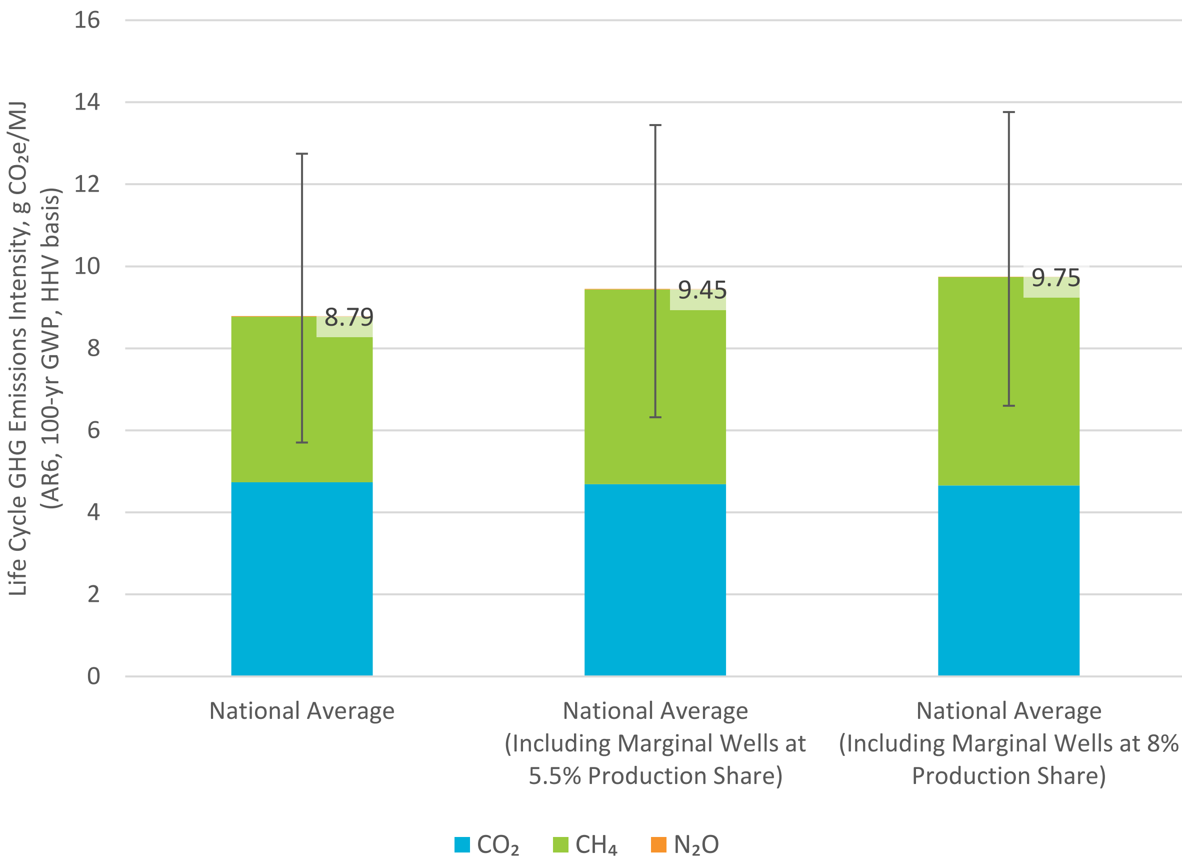


Exhibit 6-19 highlights the observed variation in the national average life cycle GHG emissions intensity profile, “production through distribution” boundary, upon accounting for methane emission intensity of marginal wells in the production stage.

Exhibit 6-19. Life cycle GHG emissions intensity for the 2020 U.S. average NG supply chain, "production through distribution" life cycle boundary, including methane emissions from marginal wells



Based on the bounding analysis criteria (see **Section 2.3**), varying the marginal well production share from 5.5 percent to 8 percent results in expected production stage GHG emissions intensity values of 2.22 and 2.38 g CO_2e/MJ (IPCC AR6, 100-yr GWP basis), respectively (as shown in **Exhibit 6-18**). No other stages are modified. This corresponds to an expected national average life cycle emissions intensity of 9.4 and 9.7 g CO_2e/MJ (IPCC AR6, 100-yr GWP basis) across the 5.5 percent and 8 percent marginal well production share, respectively (accounting for a production-normalized mean methane leakage rate of 1.2 percent from marginal well sites [13]) (see **Exhibit 6-19**).

6.5 Effect of Flaring Efficiency on the Regional and National Average Emissions Intensity Profile

Recent work by Plant et al. discusses the inefficiencies associated with flaring due to unlit flares and incomplete combustion of NG. Based on actual measurements in three basins responsible for the majority of NG flaring in the United States, the study provides an expected flaring destruction efficiency of 91.1 percent [80].

As a hypothetical scenario analysis, a flaring destruction efficiency estimate of 91.1 percent was incorporated into the NETL NG model for all techno-basin scenarios, and its impact on the regional and national average emissions profiles for the "production through distribution" life cycle boundary is provided in **Exhibit 6-20**.

Exhibit 6-20. Comparison of GHG emissions intensities using standard and revised flaring destruction efficiency

Scenario	GHG Emissions Intensity (g CO_2e/MJ)			
	AR6, 100-yr GWP		AR6, 20-yr GWP	
	Standard Flaring Efficiency (98%)	Revised Flaring Efficiency (91%)	Standard Flaring Efficiency (98%)	Revised Flaring Efficiency (91%)
Appalachian – shale	6.79	6.79	12.37	12.38
Gulf – conv	8.70	8.73	17.03	17.14
Gulf – shale	7.84	7.95	15.40	15.71
Gulf – tight	9.61	9.73	18.48	18.85
Arkla – conv	6.85	6.85	11.99	11.99
Arkla – shale	6.84	6.84	12.06	12.06
Arkla – tight	11.60	11.60	22.20	22.21
East Texas – conv	8.03	8.06	14.69	14.77
East Texas – shale	8.31	8.34	15.84	15.93
East Texas – tight	8.07	8.11	14.94	15.03
Arkoma – conv	15.13	15.11	32.05	32.02
Arkoma – shale	12.17	12.16	23.81	23.79
South Oklahoma – shale	8.86	8.87	16.14	16.18
Anadarko – conv	15.76	15.77	31.10	31.13
Anadarko – shale	9.80	9.84	17.89	18.03
Anadarko – tight	11.66	11.70	22.63	22.75
Strawn – shale	13.18	13.18	24.52	24.53
Fort Worth – shale	12.99	12.99	23.51	23.52
Permian – conv	9.73	9.87	16.56	16.97
Permian – shale	10.38	10.44	18.41	18.59
Green River – conv	12.73	12.98	19.04	19.79
Green River – tight	13.12	13.37	19.42	20.18
Uinta – conv	32.41	32.44	71.26	71.36
Uinta – tight	17.79	17.83	31.19	31.29
San Juan – CBM	17.18	17.20	33.89	33.94
San Juan – shale	25.82	25.82	44.93	44.94
Piceance – tight	8.79	8.80	17.01	17.06
National average	8.79	8.82	15.92	16.04

The reduction in flaring efficiency results in only a slight increase in the national average GHG emissions intensity. This is due to low volumes of NG flaring occurring in basins that are the biggest contributors to the national average emissions profile, such as Appalachian shale. On comparing the regional emissions profiles, the largest changes were observed for the Green River, Permian, and Gulf basin scenarios.

7 Natural Gas End Use

This section presents an alternative set of life cycle GHG emission results for domestic U.S. NG through end use (i.e., power generation [cradle-to-grave]). The NG end-use scenarios comprise combusting gas to generate electricity from an NGCC plant with and without CCS (both F-Class and H-Class), U.S. fleet NG baseload, U.S. fleet peaking, and U.S. fleet load-following. The NGCC plant with CCS scenario studies three cases with 90, 95, and 97 percent carbon capture rates.

The life cycle GHG emissions from NG-fired power are calculated by expanding the NG system boundary to include electricity generation, electricity T&D, and CO_2 T&S for the NGCC with CCS cases. A functional unit of 1 MWh of electricity delivered to consumers is the basis for comparing scenarios. **Exhibit 7-1** reports the national average power plant efficiency, heat rate, and NG feed rate for the various NG power plant scenarios modeled in this work. **Appendix C** provides more details on system boundaries, scenario definitions, data sources, and scaling factors.

Exhibit 7-1. National average heat rates for NG power plants

Power Plant Classification	Power Plant Scenario	Net Power Plant HHV Efficiency	HHV Power Plant Heat Rate (Btu/kWh)	Feed Rate (kg/MWh)
F-Class	NGCC	53.6%	6,363	128
	NGCC w/CCS at 90% capture	47.6%	7,169	145
	NGCC w/CCS at 95% capture	47.3%	7,220	146
	NGCC w/CCS at 97% capture	47.0%	7,260	146
H-Class	NGCC	55.1%	6,196	125
	NGCC w/CCS at 90% capture	49.0%	6,959	140
	NGCC w/CCS at 95% capture	48.7%	7,007	141
	NGCC w/CCS at 97% capture	48.4%	7,045	142
Fleet Scenarios	Baseload	48.7%	7,040	137
	Load-following	45.7%	7,606	148
	Peaking	34.5%	10,677	205

Exhibit 7-2 and **Exhibit 7-3** show GHG emissions for NG-fired power scenarios, including domestic consumption in NG-fired power plants. The results are presented on 100- and 20-year GWP timeframes. The error bars indicate the variation in the cradle-to-grave emissions in response to changing the upstream GHG emissions intensity from the cradle-through-transmission segment of the NG supply chain within a 95 percent confidence interval of the mean.

Exhibit 7-2. Life cycle GHG emissions through end use (IPCC AR6 100-year GWP)

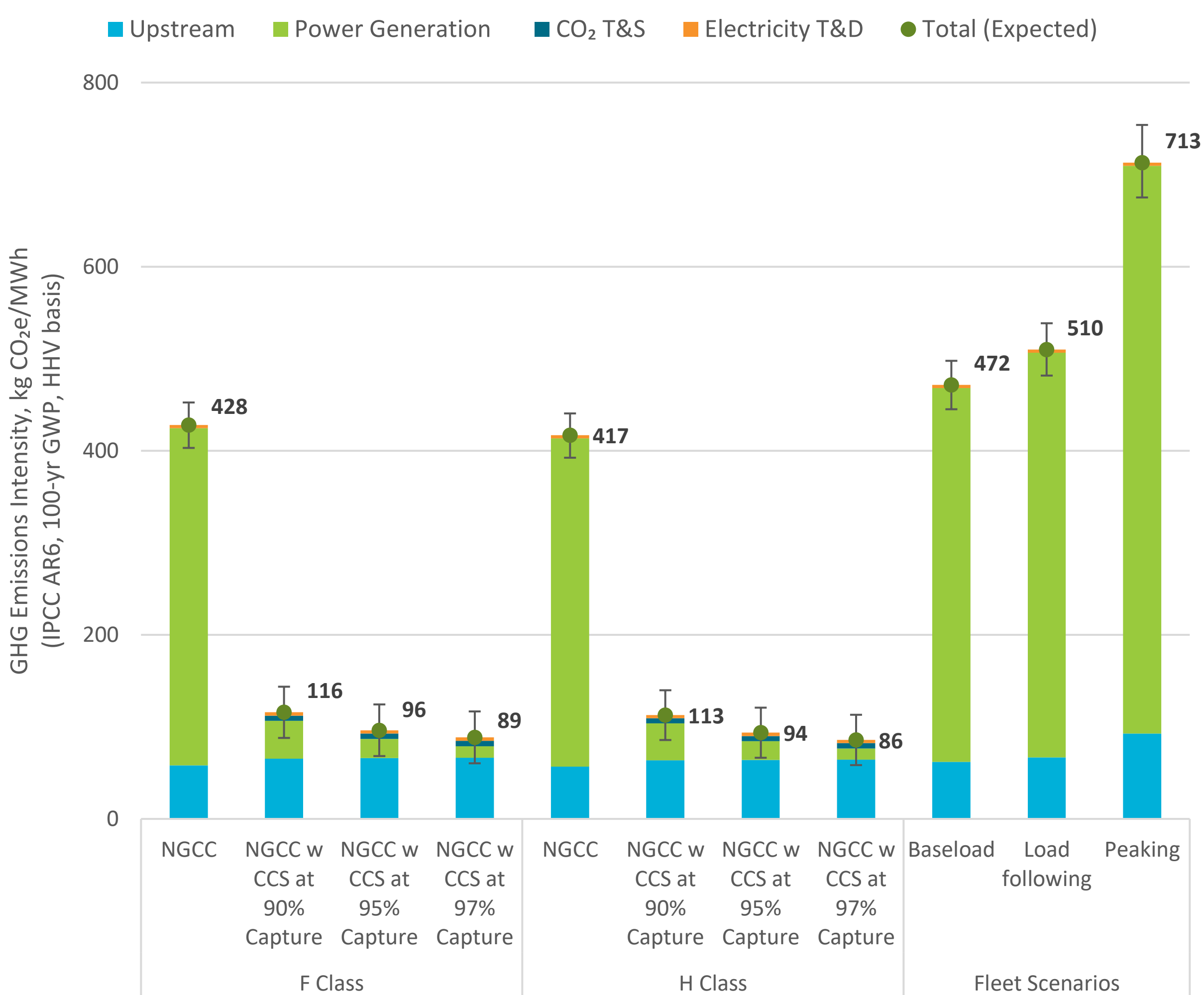
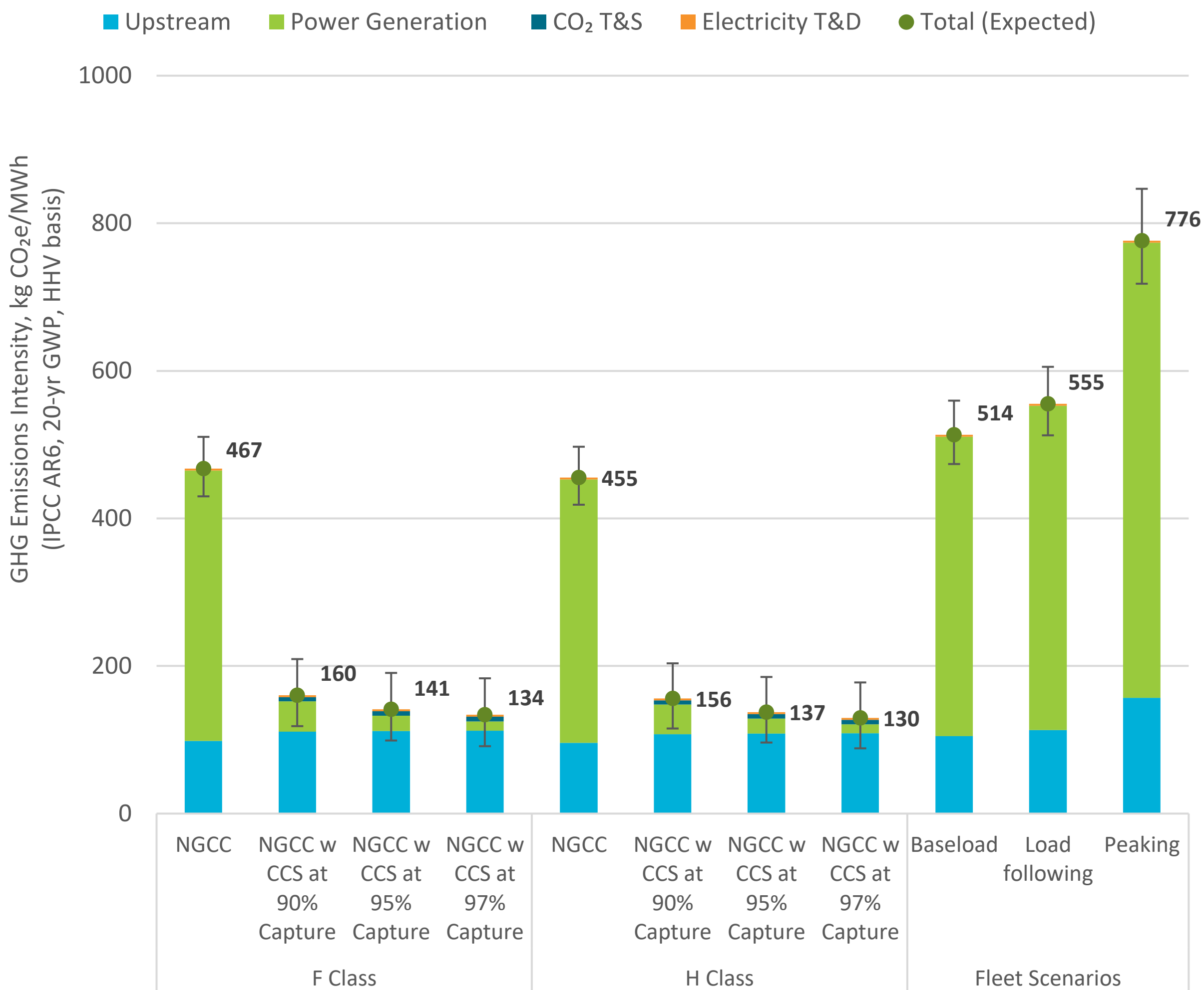


Exhibit 7-3. Life cycle GHG emissions through end use (IPCC AR6 20-year GWP)



The life cycle conclusions for the end use of NG are as follows:

- In terms of 100-year GWPs, upstream NG ("production through transmission network" life cycle boundary) accounts for 13–14 percent of life cycle GHG emissions, except for NGCC with CCS, where upstream NG accounts for 57, 69, and 75 percent of life cycle GHG emissions for F-Class and 56, 68, and 75 percent of life cycle GHG emissions for H-Class at 90, 95, and 97 percent carbon capture cases, respectively.
- Application of the 20-year GWP results in a significant increase in life cycle GHG emissions for all plant types. When changing from a 100-year to a 20-year GWP, the GHG emissions from the systems that do not have carbon capture (NGCC without CCS for both F-Class and H-Class, baseload, load following, and peaking) increase by 9 percent. The GHG emissions from the 90, 95, and 97 percent carbon capture cases for NGCC with CCS (for both F-Class and H-Class) increase by 39, 47, and 51 percent, respectively.

- A comparison of NGCC plants with and without CCS illustrates a trade-off caused by environmental controls. CCS-equipped plants require energy to capture and compress CO_2. This energy demand reduces the overall efficiency of the power plant. Compared to the other power plant scenarios, NGCC with CCS has low CO_2 emissions at the power plant but higher upstream emissions than NGCC *without* CCS because it requires more NG to generate and deliver the same amount of electricity. Even so, on a 100-year GWP timeframe, the expected life cycle GHG emissions from the NGCC with CCS scenario are 73–79 percent lower than the NGCC without CCS scenario for both F-Class and H-Class, depending on the CO_2 capture rate employed.
- When comparing life cycle GHG emissions from NG-fired power, it is important to consider the applicability of power plants. Peaking plants are less efficient and have a lower capacity factor than baseload plants. They are generally used to meet high energy demand, to supplement energy generation in case of an unexpected event, and to balance intermittent energy sources [81]. The ability to ramp up or down quickly is essential for peaking plants, which results in performance inefficiencies (due to reliance on high fuel-consuming technologies such as gas turbines, steam turbines, etc.) [81] when compared to a baseload power plant with a 90 percent operating capacity, leading to higher costs for peak power on a per MWh basis. Conversely, fleet baseload plants are expected to provide continuous power and therefore operate more efficiently than peaking or load-following power plants. A functional unit of 1 MWh is used to compare NG power scenarios, but due to the different applications of power plants, their life cycle GHG emissions are not directly comparable.

8 Comparison with Previous Results

This section compares results from the 2021 ONE Future report (2017 data year) [5] to the results presented in this work (2020 data year). Based on the degree of changes to the NETL modeling approach, GHGRP reporting changes, and updates to reflect the current state-of-the-science, it is unclear whether actual emissions intensity has increased or decreased for each techno-basin. The reported results improve accuracy based on supplementing industry-reported data with field-level measured data. New scientific understandings from measurement campaigns and improved reporting requirements will continue to improve the accuracy and understanding of U.S. NG supply emissions by techno-basin. **Exhibit 8-1** highlights the differences between the life cycle "production through distribution" stage results for the NG supply chain across the 2017 and 2020 data years for an average unit of gas. It is worth noting that this report primarily provides results on an IPCC AR6 GWP basis; however, for ease of comparison with published 2017 results, the values provided in **Exhibit 8-1** are on an IPCC AR5, 100-year GWP basis and use U.S. average "production through distribution"-stage data.

Exhibit 8-1. Comparison of 2021 ONE Future report results with current work for U.S. average delivery pathway

Techno-basin	Expected GHG Emissions Intensity (g CO_2e/MJ) (IPCC AR5, 100-yr GWP basis)		Difference
	2021 ONE Future Report (2017 data year)	Current Report (2020 data year)	
Alaska – offshore	7.49	8.07	+8%
GoM – offshore	7.51	7.22	-4%
Appalachian – shale	8.17	7.44	-9%
Uinta – conv	8.17[8]	36.98	+353%
Arkla – shale	8.22	7.45	-9%
Arkla – tight	8.62	12.85	+49%
Green River – conv	8.91	13.47	+51%
Green River – tight	10.45	13.86	+33%
Permian – conv	11.69	10.54	-10%
Gulf – tight	11.87	10.65	-10%
Gulf – conv	12.49	9.68	-23%
Gulf – shale	12.50	8.73	-30%
Permian – shale	12.92	11.33	-12%
Anadarko – shale	13.09	10.75	-18%
South Oklahoma – shale	13.39	9.72	-27%
Uinta – tight	13.76	19.37	+41%
East Texas – tight	13.89	8.88	-36%
East Texas – shale	13.92	9.20	-34%

[8] A correction was made to the U.S. GWP result (IPCC AR5, 100-year) for Uinta conventional published in the 2021 ONE Future report, with the intensity updated from 11.99 to 8.17 g CO_2e/MJ.

Techno-basin	Expected GHG Emissions Intensity ($g\ CO_2e/MJ$) (IPCC AR5, 100-yr GWP basis)		Difference
	2021 ONE Future Report (2017 data year)	Current Report (2020 data year)	
Strawn – shale	14.17	14.51	+2%
Piceance – tight	14.22	9.76	-31%
Fort Worth – shale	14.65	14.23	-3%
Arkla – conv	15.11	7.45	-51%
East Texas – conv	15.63	8.81	-44%
Arkoma – shale	16.50	13.54	-18%
Anadarko – conv	16.62	17.57	+6%
San Juan – CBM	20.50	19.15	-7%
Anadarko – tight	21.16	12.95	-39%
Arkoma – conv	26.33	17.12	-35%
San Juan – conv	33.91	-	-
San Juan – shale	-	28.07	-
National Average	**14.07**	**9.63**	**-32%**

Note: The final GHG emissions results of this study are provided on multiple GWP bases (IPCC AR4, AR5, and AR6 100- and 20-year) in **Appendix E** (available in the release package published along with this report).

The variation in GHG emissions intensity of various scenarios across the 2017 and 2020 reporting years is due to a combination of (1) changes in production shares resulting in a much greater percentage of gas coming from Appalachian Shale; (2) operational changes in the NG supply chain over the three-year period; (3) modeling changes incorporated in this study, including the energy allocation of burdens between NG and NG supply chain co-products (see **Section 4.3**), regionalization of processing-stage data (see **Section 4.5**), and regionalization of transmission- and distribution-stage data (see **Section 4.6**); and (4) modeling updates to reflect 2020 operating year conditions or the latest state of the science, such as revision of the liquids unloading throughput normalized methane emission rate values (see **Section 3.3.3**), updated EFs for gathering- and boosting-stage equipment (see **Section 4.4**), and updated EFs for commercial and industrial meters in the distribution stage (see **Section 4.6**).

A combination of these factors has affected the GHG emissions intensity across the various scenarios listed in **Exhibit 8-1**, such as the following:

- **Arkla – tight**
  The 49 percent rise in emissions intensity for the Arkla – tight scenario on a life-cycle basis is mainly due to an increase in production-stage emissions intensity from intermittent-bleed pneumatic devices and reciprocating compression, as compared to 2017 results. This change is primarily due to GHGRP reporting changes over the three-year period.

- **Green River – conv**
  The 51 percent rise in emissions intensity for the Green River – conv scenario on a life-cycle basis is primarily driven by the regionalization of processing-stage data in 2020.
- **Green River – tight**
  The 33 percent rise in emissions intensity for the Green River – tight scenario on a life-cycle basis is primarily driven by the regionalization of processing-stage data in 2020.
- **Uinta – conv**
  The significant rise in emissions intensity for the Uinta – conv scenario is primarily driven by the lack of facilities reporting to GHGRP under this scenario, with only one facility reporting in 2020, and due to regionalization of processing-stage data.
- **Gulf – conv**
  The 23 percent decline in emissions intensity for the Gulf – conv scenario is primarily due to both the gathering and boosting and the processing stage reciprocating-compression emissions intensities decreasing by 94 and 98 percent, respectively, as compared to 2017 results. The key drivers for these reductions in emissions intensity include GHGRP reporting changes over the three-year reporting period and the regionalization of processing-stage data.
- **Gulf – shale**
  The 30 percent decline in emissions intensity for the Gulf – shale scenario is primarily due to both the gathering and boosting and the processing stage reciprocating-compression emissions intensity decreasing by 50 and 77 percent, respectively, as compared to 2017 results. The key drivers for these reductions in emissions intensity include GHGRP reporting changes over the three-year reporting period and the regionalization of processing-stage data.
- **South Oklahoma – shale**
  The 27 percent decline in emissions intensity for the South Oklahoma – shale scenario is primarily due to gathering and boosting-stage reciprocating and processing-stage centrifugal compression emissions intensity decreasing by 41 and 100 percent, respectively, as compared to 2017 results. The key drivers for these reductions in emissions intensity include GHGRP reporting changes over the three-year reporting period and the regionalization of processing-stage data.
- **Uinta – tight**
  The 41 percent rise in emissions intensity for the Uinta – tight scenario on a life-cycle basis is mainly due to the significant rise in processing-stage centrifugal compression emission intensity, as compared to 2017 results. This is primarily driven by the regionalization of processing-stage data in 2020.
- **East Texas – tight**
  The 36 percent decline in emissions intensity for the East Texas – tight scenario is primarily due to production-stage intermittent-bleed pneumatics and liquids unloading and gathering and boosting-stage reciprocating-compression emissions intensity decreasing by 55, 69, and 62 percent, respectively, as compared to 2017 results. The key

drivers for these reductions in emissions intensity include GHGRP reporting changes over the three-year reporting period, and data updates to reflect 2020 operating year conditions or latest state of the science.

- **East Texas – shale**
  The 34 percent decline in emissions intensity for the East Texas – shale scenario is primarily due to production-stage reciprocating compression and liquids unloading and gathering and boosting-stage reciprocating-compression emissions intensity decreasing by 72, 69, and 62 percent, respectively, as compared to 2017 results. The key drivers for these reductions in emissions intensity include GHGRP reporting changes over the three-year reporting period, and data updates to reflect 2020 operating year conditions or latest state of the science.
- **Piceance – tight**
  The 31 percent decline in emissions intensity for the Piceance – tight scenario is primarily due to production-stage intermittent-bleed pneumatics and liquids unloading decreasing by 52 and 70 percent, respectively, as compared to 2017 results. The key drivers for these reductions in emissions intensity include GHGRP reporting changes over the three-year reporting period, and data updates to reflect 2020 operating year conditions or latest state of the science.
- **Arkla – conv**
  The 51 percent decline in emissions intensity for the Arkla – conv scenario is primarily due to production-stage liquids unloading decreasing by 94 percent as compared to 2017 results. The key driver for this reduction in emissions intensity is data updates to reflect 2020 operating year conditions or latest state of the science.
- **East Texas – conv**
  The 44 percent decline in emissions intensity for the East Texas – conv scenario is primarily due to production-stage reciprocating compression, equipment leaks, and intermittent-bleed pneumatic devices and gathering and boosting-stage reciprocating-compression emission intensities decreasing by 63, 77, 74, and 62 percent, respectively, as compared to 2017 results. The key driver for these reductions in emissions intensity is GHGRP reporting changes over the three-year reporting period.
- **Anadarko – tight**
  The 39 percent decline in emissions intensity for the Anadarko – tight scenario is primarily due to production-stage reciprocating-compression and intermittent-bleed pneumatic emission intensities decreasing by 59 and 52 percent, respectively, as compared to 2017 results. The key driver for these reductions in emissions intensity is GHGRP reporting changes over the three-year reporting period.
- **Arkoma – conv**
  The 35 percent decline in emissions intensity for the Arkoma – conv scenario is primarily due to production-stage liquids unloading decreasing by 60 percent as compared to 2017 results. The key driver for this reduction in emissions intensity is data updates to reflect 2020 operating year conditions or latest state of the science.

- **U.S. Average**

  The emissions intensity of the 2020 U.S. average profile has decreased by 32 percent, largely on account of the greater production share of gas from the (low emission) Appalachian basin, as compared to 2017 estimates. **Appendix G** provides additional details regarding changes to the methodology for estimation of production shares by well type and geography.

  To better understand the impact of the change in modeling of production shares between the 2021 ONE Future report (2017 data year) and this work (2020 data year), the 2017 U.S. average GHG intensity was recalculated using 2020 basin-level production shares. As a result, the 2017 U.S. average GHG intensity decreased from 14.1 to 11.3 g CO_2e/MJ (IPCC AR5, 100-year GWP basis), bringing the difference between 2017 and 2020 U.S. average GHG intensities down from 32 to 14 percent. In conclusion, the change in methodology for estimation of production shares accounts for around 63 percent of the gap between 2017 and 2020 U.S. average GHG emissions intensities (IPCC AR5, 100-year GWP basis). The remaining difference is due to the inclusion of measurement-informed data, operational changes in the NG supply chain between 2017 and 2020, etc.

9 Comparison with Other Literature

This section compares the results presented in this work (2020 data year) with EPA's GHGI and other recent measurement-based studies. It also provides a comprehensive data quality discussion of the complexities associated with reconciliation of top-down and bottom-up studies.

9.1 Comparison with EPA's GHGI

To aid in validating and comparing with other sources, the U.S. average emissions intensity derived from this work is compared with the NG emissions intensity estimated by normalizing GHGI U.S. natural gas system emissions [6] by marketed NG production volume from EIA [82] for the 2020 data year. As a result of this comparison, several data gaps were identified and incorporated within this work, including emissions from separators and meters/piping (production stage); atmospheric tanks and yard piping (gathering and boosting stage); and M&R stations (transmission and storage stage). Since GHGI accounts for combustion emissions (except for flaring) separately, CO_2 emissions from natural gas systems are excluded in this comparison, and only methane emission intensities are studied. A detailed stage-level comparison of CH_4 emissions intensities between GHGI and this work is provided in **Exhibit 9-1**.

Exhibit 9-1. Comparison of methane emissions intensities between GHGI and this work

Stage	GHGI Intensity (g CH_4/MJ)	Current Report (g CH_4/MJ)	Difference (Current Report vs. GHGI)
Onshore Production	4.83E-02	4.47E-02	-8%
Gathering and Boosting	3.78E-02	2.80E-02	-29%
Processing	1.25E-02	1.43E-02	+15%
Transmission and Storage	4.10E-02	1.59E-02	-61%
Distribution	1.40E-02	3.26E-02	+133%
Total	1.55E-01	1.36E-01	-12%

The key reasons for the discrepancy between emission intensities estimated from the two data sources include:

- **Boundary scope**

  EPA's GHGI provides a national-level emissions inventory, whereas this work provides the emissions intensity associated with an average unit of NG delivered to consumers.

- **Incorporation of activity data**

  The differing boundary scope of the two data sources results in varying approaches for incorporation of activity data into the analysis. As an example, for a wide range of emission categories (including pneumatic devices and compressors at gathering and boosting stage), EPA's GHGI relies on scaling GHGRP data to generate national-level activity data, whereas this work typically uses reported GHGRP activity data directly.

- **Differing data sources for EFs**

  This work has incorporated multiple measurement-informed study results into the modeling of emissions from various emissions sources, including gathering and boosting-stage emission sources such as pneumatic devices, compressors, AGR units, valves, connectors, and PRVs (see **Section 4.4**), and distribution stage emission sources such as industrial and commercial customer meter sets (see **Section 4.6**).

- **Accounting for stage losses**

  This work provides emissions intensities on a life-cycle basis that account for NG consumption and losses at each stage of the supply chain. Since EPA's GHGI does not explicitly report emissions intensities, these values are estimated by normalizing the reported stage-level methane emissions by the total marketed NG production, which is not functionally equivalent to methane emission intensities derived from a life cycle study.

- **Modeling approach**

  The modeling of emissions from transmission-reciprocating compressors is discussed as an example of the differing modeling approaches between this work and EPA's GHGI. GHGI relies on work by Zimmerle et al. [59] and the Gas Research Institute [83] for emissions and AF data to help estimate emissions from transmission reciprocating compressors, whereas this work relies on an engineering-based approach that uses compressor horsepower-hour data from GHGRP, which are converted to a compressor input fuel quantity basis using compressor thermal efficiency, NG density, and NG heating values. Finally, these compressor fuel inputs are normalized by NG throughput and multiplied with AP-42 EFs [32] for modeling emissions from transmission-reciprocating compressors.

9.2 Comparison with Other Measurement-Based Literature

Recent studies including measured values have concluded that national GHG emissions inventories typically underestimate methane emissions [84, 85]. The NETL NG baseline work incorporates updated emissions estimates based on recent literature for various emissions sources across the NG supply chain; however, data from measurement studies need to be aligned with the boundaries, scope, and, ideally, process-level granularity used in the NETL NG model prior to their incorporation into the modeling framework. **Exhibit 9-2** highlights the important data quality metrics relevant to determining the potential inclusion of measurement-based studies into the NETL NG baseline work.

Exhibit 9-2. Metrics for data quality assessment of measurement-based studies

Data Quality Indicator: Representativeness	Determining Factor	Rating Scale			NG Baseline Requirement
		High	Moderate	Low	
Operations	How representative are EFs of operations?	Data from field sites, whether at component, equipment, site level, or basin level	Data but may only reflect nominal operating conditions	Single data point at unknown operating condition	Moderate or High
Product/technology	Is the study able to attribute emissions to NG?	Data representative of only NG product operations	Data allocated to co-products at the facility level, process level, or component level	Data allocated to co-products across multiple facilities, basin, region, or broader level	Moderate or High
Geographic	Do the reported data adequately represent operations within the geographical area of interest (e.g., basin or national level)?	Data from basins/ equipment with coverage of all modeled regions/ equipment population	Data from basins/ equipment with coverage of high proportion of modeled regions/ equipment population	Data from basins/ equipment with coverage of few basins/smaller equipment population	Moderate or High
Temporal	How representative are emissions and EFs of the target year?	Data within one year of target year (currently 2020)	Data within four years or EFs from normal operating conditions that are not expected to change	Five years or older	Moderate or High

Data companies that have submitted to EPA under GHGRP continue to serve as the foundational basis of this study, and limitations associated with those data (e.g., reporting gaps related to methane emissions from “other large release events”) are carried over. EPA has finalized revisions to GHGRP to improve accounting of emissions and address reporting gaps, however data reported under those updated methods are not yet available. Some of EPA’s changes include adding new emissions sources—other large release events—to account for abnormal methane leaks, revisions to existing emission calculation methodologies to include the use of new technologies such as remote sensing for direct measurements, etc. [1]. These changes are expected to improve the accuracy of emissions estimates for the NG supply chain and will be reviewed and incorporated into future versions of the NETL NG model, as appropriate.

Measurement studies working on reconciling bottom-up and top-down inventories [86, 87] have highlighted multiple reasons for the discrepancies frequently identified between these two approaches to developing inventories, some of which are listed below.

- Temporal variability in emissions measured by top-down approaches are usually snapshot measurements, as compared to bottom-up inventories that combine traditional estimation methodologies (i.e., using activity counts, annual operating hours, EFs) with newer measurement data.
- Use of existing average EFs in bottom-up inventories typically underestimates emissions by not representing a facility's emissions profile and not sufficiently accounting for large emissions sources (abnormal methane leaks, malfunctioning equipment, etc.).
- There are challenges associated with attributing emissions from top-down inventories to a specific facility or marketed product due to the complexity of systems, co-location of facilities with different products, and obstructions or other physical impediments.

Tracking emissions at NG upstream and midstream facilities over longer durations is a potential way to build confidence in top-down estimates. Continuous emissions monitoring through use of sensors, optical gas imaging equipment, etc., might aid in the validation of top-down measurements; however, incorporating these steps into a facility's operations results in additional costs, and it is necessary to ensure that uncertainties from these continuous emissions-monitoring methods (which are also under development) are characterized properly.

It is also worth noting that large-scale, top-down, measurement-based studies usually focus on a specific basin(s), which may not be representative of a single facility's operations within a basin or operations across other regions, and issues associated with improper attribution of methane emissions measured via top-down studies among various sources (e.g., coal mines, oil and gas wells, etc.) further impede the incorporation of updated estimates into bottom-up modeling frameworks.

Major top-down studies that have attempted to assign emissions to either oil or NG have relied on allocation, specifically energy allocation, to assign basin-level methane measurements to oil, condensate, or gas production. While allocation is a valid approach to co-product management in LCA, it is last in the hierarchy of preferred methods for handling the assignment of emissions to co-products. Further, in the context of most—if not all—LCAs, allocation is used at a facility level, process level, or component level to assign those emissions. NETL is not aware of any LCAs that have been performed where allocation is used to assign the aggregate emissions of multiple facilities across vast geographical areas. In terms of oil and NG production at a single well site, using allocation of site-level methane emissions would be consistent with past LCA practice. In terms of the ISO co-product management hierarchy [88], before resorting to allocation, it is preferable to partition the system such that if there are any methane-emitting activities from components that are used only for the gas-production stream, those emissions would be assigned to NG production *before* allocation. Then, only emissions from completely shared equipment, such as emissions from the well itself, would be allocated. The basin-level emissions reported in these top-down studies are, in fact, the cumulative emissions from many facilities that can solely produce oil, solely produce gas (some with condensate), or produce mixes of these products. Using a tool like allocation to assign emissions across many different facilities crossing all stages of production ignores the ISO hierarchy, represents a methodology that has not been fully considered by the LCA community, and is likely to produce results that are not representative of any of the individual products.

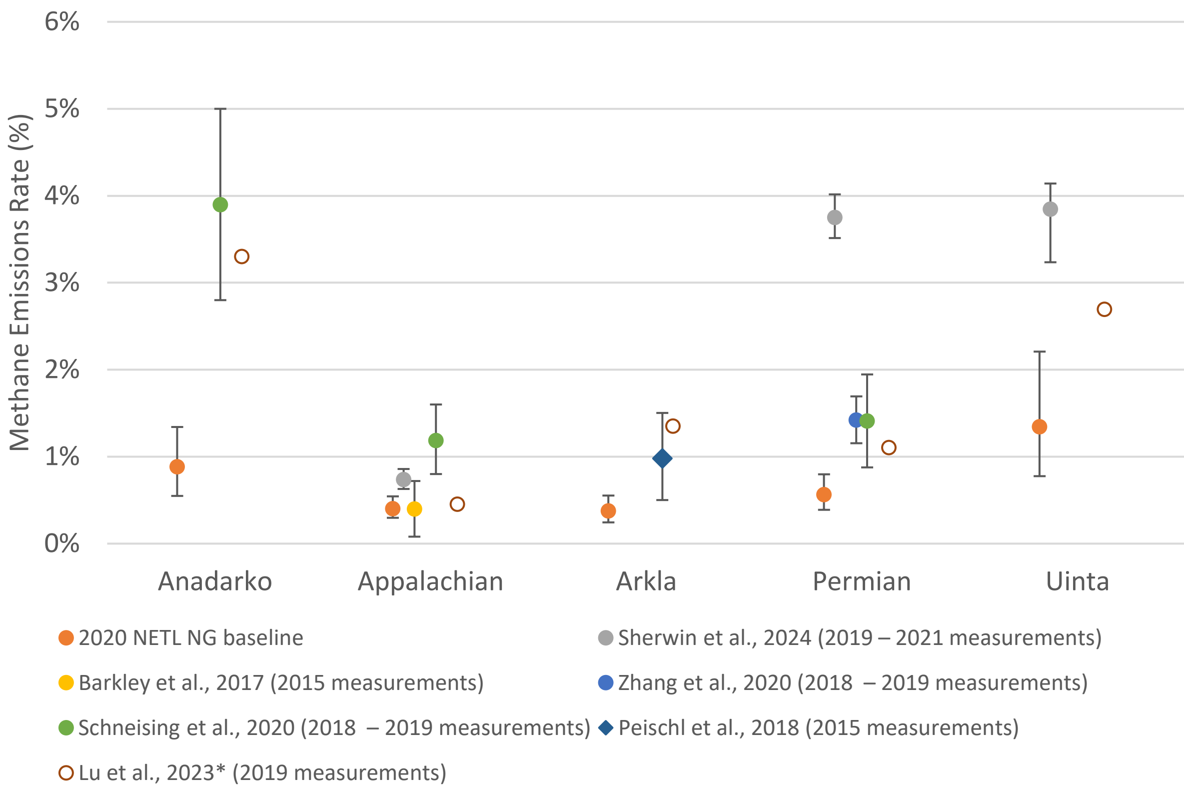
Chen et al. [89] investigated the impact of allocation methods on the bottom-up life cycle GHG emissions estimates developed for oil and gas operations in the Eagle Ford basin by highlighting the uncertainties associated with allocating emissions at the basin or sub-basin level as compared to process-level allocation.[9] The Chen et al. study boundary includes emissions from various sources associated with both oil and gas operations (as well as solely oil and solely gas operations) and reports a ~15 percent average difference between total GHG emissions allocated to natural gas, NGL, and oil products based on the allocation technique employed for the entire basin [89]. Furthermore, the observed differences in results from wet gas production regions that generate substantial volumes of both gas and liquids can be even larger [89]. The better characterization of uncertainties and development of more granular estimates by top-down measurement studies will facilitate the integration of their results with bottom-up modeling frameworks. Nevertheless, a comparison with recent measurement-based studies to highlight the existing differences (and similarities) between top-down and bottom-up modeling methodologies is an important metric for future reconciliation, and the following section discusses this in more detail.

Exhibit 9-3 provides a basin-level comparison of “production through transmission” boundary results of the NETL NG baseline work with recent measurement studies. This comparative analysis covers studies of five production basins, with the highest number of data points available for the Appalachian and Permian basins (5 each) on account of the high number of survey campaigns carried out in these regions.

It is important to note that all the assessed observation-based studies report methane emissions from both oil and gas infrastructure, and methane emission rates are provided on a gross-production basis. While allocation of methane emissions using a single method is not consistent with the ISO hierarchy, as discussed above, for the purposes of this comparative analysis, NETL has allocated emissions to the gas stream on an energy basis (at the basin level) because NETL does not have access to the data to take a more refined approach, if the necessary data even exist. In addition, NETL has converted methane emissions rates from a gross gas production to a marketed gas production basis by mapping state-level NG gross withdrawal and marketed production data from EIA to relevant basins of interest. This is the same methodology followed by the recent National Petroleum Council study [90] for the purpose of sensitivity analysis. The conversion from a gross withdrawal to a marketed gas production basis enables direct comparison with the NETL NG baseline work, which provides “production through transmission”-stage emissions results on a per MJ of NG delivered basis. For certain production basins, due to high volumes of NG venting and flaring or gas repressuring, the difference between gross gas withdrawals and marketed gas production can be significant.

[9] The NETL NG model applies process-level energy allocation.

Exhibit 9-3. Comparison of "production through transmission network" methane emission rates across the literature



*Only mean methane emission rate estimates available

Notes:

1. Only methane emission rates allocated to the NG stream are shown here, for ease of comparison with NETL NG baseline work.
2. Confidence intervals are provided for each study as available; however, certain studies only report mean emission rates.
3. The methane emission rate estimates from measurement-based studies provided in **Exhibit 9-3** are on a marketed gas production basis, for ease of comparison with the "production through transmission"-stage results of the NETL NG baseline work.

A basin-level assessment of the various studies analyzed is discussed below.

- Appalachian
  The mean methane emission rate estimates across the Barkley et al. (0.40 percent) [91] and Lu et al. (0.45 percent) [92] studies are within the confidence intervals reported by the NG baseline work (0.30–0.54 percent). In addition, the upper range of the NG baseline work's estimate is within 0.1 percent of the lower range reported by the Sherwin et al. study (0.63 percent) [93]. This depicts alignment of the NG baseline results with the Appalachian basin methane emissions estimates reported in recent measurement-informed literature. The only exception is the Schneising et al. study [94], which reports much higher estimates (1.19 percent) as compared to other literature studied in this analysis.

- Permian

  For the Permian basin, measurement-informed studies [92, 94, 95, 93] depict a wide range of methane emission rates, varying from 1.11 to 3.75 percent, which are higher than the emissions range reported by NG baseline work (0.39–0.80 percent). This wide variability in methane emission estimates is also validated by results of the multiple emissions measurement campaigns carried out as part of the Sherwin et al. study [93], depicting methane loss rates ranging from 2.1 to 9.63 percent (including both oil and gas operations). These measurements were conducted across varying temporal ranges and covered different geographical regions within the basin.

- Anadarko

  The two measurement-informed studies [92, 94] report much higher methane emission rates (3.30 and 3.90 percent) than the NG baseline work (0.55–1.34 percent). This comparison highlights the discrepancy between bottom-up studies incorporating measurement-informed data to a certain extent and top-down studies.

- Arkla

  The comparative analysis uses estimates reported by other literature for the Haynesville basin as a proxy for the Arkla basin, for ease of comparison with estimates reported in the NG baseline work. The confidence intervals of the NG baseline work (0.24–0.55 percent) overlap with the emission estimates reported by the Peischl et al. study (0.50–1.50 percent) [96]. Only a point estimate from the Lu et al. study (1.35 percent) [92] is used in this comparative analysis; however, it is plausible that the lower range of the confidence interval for that point estimate might fall within or close to the uncertainty range reported by the NG baseline work.

- Uinta

  As noted with the Permian basin comparison, measurement-based studies [92, 93] depict much higher methane emission rates (2.70 and 3.85 percent) than NG baseline work (0.78–2.21 percent), highlighting the discrepancy between bottom-up and top-down modeling approaches.

Exhibit 9-4 highlights the variation in reported methane emissions intensity estimates across various measurement studies by production basin as well as allocation basis, and **Exhibit 9-5** provides the gas to total oil and gas production fraction (energy basis), along with the ratio of marketed gas production to gross gas withdrawals for each of the five production basins assessed.

Exhibit 9-4. Methane emissions intensity for all analyzed measurement studies on a multiple-allocation basis, by production basin

Basin	Allocation Basis[a]	Measurement Studies					
		Sherwin et al., 2024 [93]	Barkley et al., 2017 [91]	Zhang et al., 2020 [95]	Schneising et al., 2020 [94]	Peischl et al., 2018 [96]	Lu et al., 2023 [92]
Anadarko	Unallocated	-	-	-	-	-	4.35%
	Allocated – gross gas production basis	-	-	-	-	-	3.30%
	Allocated – marketed gas production basis	-	-	-	-	-	3.30%
Appalachian	Unallocated	0.75%	0.40%	-	1.19%	-	0.46%
	Allocated – gross gas production basis	0.74%	0.40%	-	1.19%	-	0.45%
	Allocated – marketed gas production basis	0.74%	0.40%	-	1.19%	-	0.45%
Arkla	Unallocated	-	-	-	-	1.00%[b]	1.38%[c]
	Allocated – gross gas production basis	-	-	-	-	0.98%	1.35%
	Allocated – marketed gas production basis	-	-	-	-	0.98%	1.35%
Permian	Unallocated	5.29%	-	3.70%	3.70%	-	2.87%
	Allocated – gross gas production basis	3.51%	-	1.33%[d]	1.32%	-	1.03%
	Allocated – marketed gas production basis	3.75%	-	1.42%	1.41%	-	1.11%
Uinta	Unallocated	5.73%	-	-	-	-	2.82%
	Allocated – gross gas production basis	3.84%	-	-	-	-	2.69%
	Allocated – marketed gas production basis	3.85%	-	-	-	-	2.70%

[a] The unallocated value represents the methane emissions intensity associated with both oil and gas production in a particular basin, while the allocated values represent methane emissions intensity allocated to gas only.
[b] Since the Peischl et al. study [96] does not report any allocation factors, a 98 percent gas fraction to total oil and gas production (energy basis) ratio for the Arkla/Haynesville basin is assumed based on Lu et al. [92]; the Haynesville basin estimate is used as a proxy for the Arkla basin for ease of comparison with NETL NG baseline work.
[c] Haynesville basin estimate used as a proxy for Arkla basin, for ease of comparison with NETL NG baseline work.
[d] Since the Zhang et al study [95] does not report any allocation factors, we assume a 36 percent gas fraction to total oil and gas production (energy basis) ratio for the Permian basin based on Lu et al [92].

Exhibit 9-5. Gas fraction to total oil and gas production and gas marketed production to gross gas withdrawal ratio for analyzed basins

Basin	Gas Fraction to Total Oil and Gas Production	Gross Gas/Marketed Gas Ratio Development	
		Proxy EIA State-Level Data	Marketed to Gross Gas Withdrawal Ratio
Appalachian	0.98	Average of Ohio, Pennsylvania, and West Virginia	1.00
Anadarko	0.69[a]–0.76[b]	Oklahoma	1.00
Haynesville/Arkla	0.98	Louisiana	1.00
Permian	0.36[c]–0.39[d]	Texas	0.94
Uinta	0.60[d]–0.78[b]	Utah	1.00

Notes: [a] Estimate from Schneising et al. [94]; [b] Estimate from Lu et al. [92]; [c] Estimate from Schneising et al. and Lu et al. [94, 92]; [d] Estimate from Sherwin et al. [93]

Exhibit 9-6 classifies each of the analyzed measurement-based studies in terms of its boundaries and scopes and discusses the data quality metrics associated with each study in more detail.

Exhibit 9-6. Classification of measurement-based studies and data quality discussion

Study	Boundary Scope	Allocation Scheme[a]	Data Quality Discussion	Data Representativeness			
				Operations	Product/ Technology	Geographic	Temporal
Measurement-Based Studies Not Incorporated in NG Baseline Work							
Sherwin et al., 2024 [93]	Oil and gas, basin-level measurement results	Basin-level energy allocation	Suggests basin-level energy allocation to estimate burden associated with gas only. Estimates from Sherwin et al. are not incorporated into the NETL NG baseline model.	High	Low	Low to moderate	High
Barkley et al., 2017 [91]	Only gas, focused on Northeast PA	N/A	Energy allocation not necessary because it is functionally NG-only. Emission rates of the study are consistent with the NETL estimate.	High	Low	Moderate	Low
Zhang et al., 2020 [95]	Oil and gas, basin-level measurement results	Basin-level energy allocation	Study presents emissions estimates for combined oil and gas and normalized by gross gas production (i.e., assigned all emissions to gas). However, to enable comparison across studies, basin-level energy allocation was implemented to estimate the burden associated with gas only. Estimates from Zhang et al. are not incorporated into the NETL NG baseline model.	High	Low	Moderate	Moderate
Schneising et al., 2020 [94]	Oil and gas, basin-level measurement results	Basin-level energy allocation	Study provides oil and gas production estimates (energy basis) at the basin level and reports combined oil and gas leakage rates. However, to enable comparison across studies, basin-level energy allocation was implemented to estimate the burden associated with gas only. Estimates from Schneising et al. [94] are not incorporated into this version of the NETL NG baseline model.	High	Low	Moderate	Moderate
Peischl et al., 2018 [96]	Oil and gas, basin-level measurement results	Basin-level energy allocation	Study reports produced NG emitted to the atmosphere at the basin level. However, to enable comparison across studies, basin-level energy allocation was implemented to estimate the burden associated with gas only. Estimates from Peischl et al. are not incorporated into the NETL NG baseline model.	High	Low	Moderate	Low

Study	Boundary Scope	Allocation Scheme[a]	Data Quality Discussion	Data Representativeness			
				Operations	Product/ Technology	Geographic	Temporal
Lu et al., 2023 [92]	Oil and gas, basin-level measurement results	Basin-level energy allocation	Study reports produced NG emitted to the atmosphere at the basin level. However, to enable comparison across studies, basin-level energy allocation was implemented to estimate the burden associated with gas only. Estimates from Peischl et al. are not incorporated into the NETL NG baseline model.	High	Low	Moderate	High
Measurement-based Studies Incorporated in NG Baseline Work							
GSI, 2018 [97]	Gathering and boosting facilities	N/A, provides process-level data	Based on measurements at gathering and boosting facilities in the Gulf basin, this study provides updated EFs at the equipment level that are aligned with the NETL NG model. These updated EFs have been incorporated into the NETL NG modeling framework.	High	Moderate	Moderate	Moderate
Zimmerle et al., 2019 [58]	Gathering and boosting facilities	N/A, provides process-level data	Based on measurements at 180 gathering facilities across 11 U.S. states, this study provides updated EFs at the equipment level that are aligned with the NETL NG model. These updated EFs have been incorporated into the NETL NG modeling framework.	High	Moderate	Moderate	Moderate
Moore et al., 2019 [60]	Distribution stage	N/A, provides process-level data	Based on multiple measurement campaigns across six U.S. geographical regions, this study reports updated EFs for distribution-stage industrial and commercial customer meters, aligned with process-level parameterization and regionalization within the NETL NG model. These updated EFs have been incorporated into the NETL NG modeling framework.	High	High	Moderate	Moderate

[a] The allocation scheme reflects the accounting technique followed for ensuring the results from measurement-based studies are on a comparable basis to NETL NG baseline results (focused on emissions intensity of NG supply chain while excluding impact of crude oil).

In terms of operational representativeness, all studies in **Exhibit 9-5** are rated as "high" since they represent actual basin-, site-, or process-level measurements. On a product/technology data representativeness scale, the various top-down studies [93, 91, 95, 94, 96, 92] are rated as "low" since they represent methane emissions from multiple sources (oil and gas operations, coal mining, etc.) that require allocations on aggregate data to estimate the emissions burden associated with the NG supply chain only, whereas the process- or equipment-level emissions measurement studies are rated as "moderate" [58, 97] if they represent measured emissions from sources that support operations associated with both NG and NG supply chain co-products, and "high" [60] if they represent emissions solely associated with NG processes. On a geographical data representativeness scale, most studies are rated as "moderate" since they only cover some but not all the modeled regions in the NETL NG model. For process-level emissions measurement studies, measurement campaigns carried out in a few select basins for emissions sources that are likely to be representative across all basins have also been rated as "moderate" [97]. Finally, on a temporal data representativeness scale, depending on the relative closeness of the study's measurement period to the target year (2020), the various studies are marked from "low" to "high." In conclusion, measurement-based studies rated "moderate" to "high" across all data representativeness categories are incorporated into the NETL NG modeling framework, whereas studies rated lower are not.

Even though bottom-up inventories of NG may seem to underestimate methane emissions from NG infrastructure, they are expected to continue to serve a key role in facilitating investment and setting emissions reduction standards and guidelines. The continual improvement in bottom-up inventories through the inclusion of updated equipment-level EFs, incorporation of newer emissions sources, and better accounting of abnormal methane leaks are some of the necessary steps for ensuring accurate emissions assessments and eventual reconciliation with top-down approaches. As part of future updates, the NETL NG baseline work welcomes the opportunity to incorporate measurement studies that better meet data quality requirements provided in **Exhibit 9-2.**

10 CONCLUSIONS

This analysis provides an understanding of the life cycle environmental burdens of the NG supply chain. A complete set of air emissions, water emissions, water use, and land use was generated for 29 NG supply chain scenarios. Key findings focus on GHG emissions and water burdens:

- For the "production through distribution" life cycle boundary, the national average life cycle GHG emissions from the NG supply chain are 8.8 g CO_2e/MJ (with a 95 percent mean confidence interval of 5.7–12.7 g CO_2e/MJ). The CH_4 emission rate (kg CH_4/kg NG delivered) for the national average is 0.74 percent, with a 95 percent mean confidence interval ranging 0.51–1.02 percent. Due to the use of non-parametric bootstrapping to sample the mean confidence intervals for complex data distributions, the mean confidence intervals on these results are symmetrical, yet indicative of the high variability in the raw data.
- For the "production through transmission network" life cycle boundary, the national average life cycle GHG emissions from the NG supply chain are 7.8 g CO_2e/MJ (with a 95 percent mean confidence interval of 4.9–11.5 g CO_2e/MJ). The CH_4 emission rate (kg CH_4/kg NG delivered) for the national average is 0.56 percent, with a 95 percent mean confidence interval ranging 0.37–0.80 percent. As noted previously, due to the use of non-parametric bootstrapping to sample the mean confidence intervals for complex data distributions, the mean confidence intervals on these results are symmetrical, yet indicative of the high variability in the raw data.
- An NG consumption-weighted national average profile was estimated using the percent of gas estimated to flow through the transmission network to consumers and of gas that flows through the distribution network to consumers, and using the "production through distribution" and "production through transmission network" life cycle boundary results. The NG consumption-weighted national average GHG emissions intensity is 8.3 g CO_2e/MJ (with a mean confidence interval of 5.3–12.2 g CO_2e/MJ, AR6 100-yr GWP basis) and CH_4 emissions rate (kg CH_4/kg NG delivered) is 0.65 percent, with a 95 percent mean confidence interval ranging 0.45–0.92 percent.
- Accounting for a production-normalized methane emission rate of 1.2 percent from marginal well sites results in an expected national average life cycle emissions intensity of 9.4–9.7 g CO_2e/MJ for the "production through distribution" life cycle boundary, across the 5.5–8 percent marginal well production contribution to total U.S. NG production.
- The top contributor to CO_2 emissions is combustion exhaust from compressor systems; top contributors to CH_4 emissions are liquids unloading, pneumatic devices, customer meters, and other venting from compressor systems. Compressor systems and pneumatic systems are prevalent in nearly all supply chain stages, so compressor and pneumatic device emissions are key emission drivers in all supply chain stages. These

emission sources present a significant opportunity to decarbonize the existing NG supply chain in the United States.

- The regional NG emissions intensity profiles exhibit a wide range of scenarios. For the "production through distribution" life cycle boundary, upon consideration of all 14 onshore gas production basins covered in this study, the Uinta – conv scenario with gas delivered to the Southwest (34.2 g CO_2e/MJ, with a 95 percent mean confidence interval ranging 23.1–48.1 g CO_2e/MJ, IPCC AR6 100-year GWP) has the highest GHG emissions intensity. On the contrary, the Appalachian – shale scenario with gas delivered to the Midwest (5.9 g CO_2e/MJ, with a 95 percent mean confidence interval ranging 3.7–8.8 g CO_2e/MJ, IPCC AR6 100-year GWP) has the lowest GHG emissions intensity.
- While flowback water may represent a large volume of water over a relatively short period during well completion, when normalized over the lifetime of the well, flowback water is overshadowed by the volume of produced water that is returned from the formation. Produced water volumes are highly variable, and better data are required to fully understand the magnitude to which produced water volumes exceed flowback water volumes.
- The uncertainty in results for NG systems is driven by variability in the underlying data and modeling decisions. The multiple scenarios in this analysis are a combination of different production basins and extraction technologies; they show that geographic and technological variability is a large source of uncertainty. More research and analysis is necessary to identify other drivers of uncertainty (e.g., variability in infrastructure age, variability in operator practices, temporal inconsistencies within data, and errors in data collection and reporting).
- When expanding system boundaries to include the generation and delivery of electricity to consumers, upstream NG accounts for 13–14 percent of life cycle GHG emissions for NGCC power plants *without* carbon capture systems (using 100-year GWPs). For advanced NG power plants that capture CO_2 and transport it by pipeline to saline aquifer storage sites, upstream NG accounts for 57, 69, and 75 percent of life cycle GHG emissions at 90, 95, and 97 percent carbon capture cases, respectively.
- Overall, as compared to 2017 estimates based on work by Rai et al. [5], the emissions intensity of the 2020 U.S. average profile decreased by 32 percent on account of the greater production share of gas from the Appalachian basin. However, based on the degree of changes to the NETL modeling approach, GHGRP reporting changes, and updates to reflect the current state-of-the-science, it is difficult to assess whether the actual emissions intensity has increased or decreased. The reduction in GHG emissions intensity is due to a combination of multiple factors, including (1) changes in production shares resulting in a much greater percentage of gas coming from Appalachian shale; (2) operational changes in the NG supply chain over the three-year period; (3) modeling changes incorporated in this study, including the energy allocation of burdens between NG and NG supply chain co-products, regionalization of processing-stage data, and regionalization of transmission and distribution-stage data; and (4) modeling updates to

reflect 2020 operating year conditions and the latest state of the science, such as revision of liquids unloading throughput normalized methane emission rate values, updated EFs for gathering and boosting-stage equipment, and updated EFs for commercial and industrial meters in the distribution stage. The reported results improve accuracy based on supplementing industry-reported data with field-level measured data. New scientific understandings from measurement campaigns and improved reporting requirements will continue to improve the accuracy and understanding of U.S. NG supply emissions by techno-basin.

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APPENDICES

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ACRONYMS AND ABBREVIATIONS

°C	Degrees Celsius
AAPG	American Association of Petroleum Geologists
ANGA	America's Natural Gas Alliance
API	American Petroleum Institute
bbl	Barrel
Btu	British thermal unit
CBM	Coalbed methane
CCS	Carbon capture and storage
CD	Casing diameter
CH_4	Methane
CO_2	Carbon dioxide
conv	Conventional
eGRID	Emissions and Generation Resource Integrated Database
EIA	Energy Information Administration
EPA	Environmental Protection Agency
ft^2	Square feet
GHG	Greenhouse gas
GHGRP	Greenhouse Gas Reporting Program
GoM	Gulf of Mexico
GWP	Global warming potential
HHV	Higher heating value
hr	Hour
HR	Venting duration
in	Inches
in^2	Square inches
IPCC	Intergovernmental Panel on Climate Change
kg	Kilogram
kWh	Kilowatt-hour
Mcf	Thousand cubic feet
MJ	Megajoule
MMBtu	Million British thermal units
MW	Megawatt
MWe	Megawatt electrical
MWh	Megawatt-hour
N/A	Not applicable
N_2O	Nitrous oxide
NEMS	National Energy Modeling System
NETL	National Energy Technology Laboratory
NG	Natural gas
NGCC	Natural gas combined cycle
NGSI	Natural gas sustainability initiative
O&G	Oil and gas
psi	Pounds per square inch
psia	Pounds per square inch absolute
psig	Pounds per square inch gauge
scf	Standard cubic feet
SFR	Standard Flow Rate
SF_6	Sulfur hexafluoride
SP	Shut-in pressure
TD	Tubing diameter
TNME	Throughput normalized methane emissions
U.S.	United States
V	Venting frequency
WD	Well depth
yr	Year
Z	Venting plunger-lift well count

APPENDIX A: ADDITIONAL MODELING PARAMETERS

The Appendix A Excel file in the release package published along with this report provides the following various modeling parameter exhibits, which highlight the various modeling parameters incorporated into the natural gas model for developing regional and national average emissions profiles.

Exhibit A-1. Regional venting data for production

Exhibit A-2. Regional venting data for gathering and boosting

Exhibit A-3. Regional venting data for processing

Exhibit A-4. Regional venting data for transmission network

Exhibit A-5. Regional venting data for distribution

Exhibit A-6. Regional fugitive data for production

Exhibit A-7. Regional fugitive data for gathering and boosting and processing

Exhibit A-8. Regional fugitive data for transmission network and distribution

Exhibit A-9. Regional stage scaling factors

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Appendix B: Water Burdens

It is worth noting that while efforts were made to identify updated data sources and methods to improve the modeling of water burdens in this work, no significant new sources or methods were discovered, and data have remained unchanged from the 2019 natural gas (NG) baseline report [1].

B.1 Water Release Volume Parameters

The volumes given in **Exhibit B-1** describe the total amount of flowback and produced water that is discharged from wells (either per well or per kg of NG produced). Data are stratified by well type only, as they are reflective of differences in the volume of flowback and produced water returned by different well types. They do not reflect differences in best practices or the frequency of incidents occurring at the well site. All wells are assumed to have the same probability for occurrence of an incident as well as the probability that the spill volume reaches an environmental receptor, as described in the report.

Exhibit B-1. Discharge volumes for flowback and produced water incidents

Well Type	Minimum Volume	Expected Volume	Maximum Volume	Units
Shale	1.51E+02	3.75E+03	5.30E+04	liters per well
Tight	1.51E+02	3.75E+03	5.30E+04	liters per well
Conv	2.10E-06	5.19E-05	7.34E-04	liters per kg of NG
CBM	1.24E-06	3.08E-05	4.36E04	liters per kg of NG

B.2 Water Management Parameters

The Appendix B Excel file in the release package published along with this report provides the following produced and flowback water management parameters for all conventional, coalbed methane (CBM), shale, and tight basins analyzed in this study [2, 3, 4]:

Exhibit B-2. Produced water management data

Exhibit B-3. Flowback water management data

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APPENDIX C: NATURAL GAS END USE

C.1 NGCC SCENARIOS

The natural gas combined cycle (NGCC) technologies are characterized by the National Energy Technology Laboratory (NETL) fossil energy generation baseline study [5]. The NGCC power plant is a thermoelectric generation facility with a net power output of 727 MWe (F-Class) and 992 MWe (H-Class). It has two parallel, advanced F-Class or H-Class gas-fired combustion turbines, and each combustion turbine is followed by a heat recovery steam generator that produces steam that is fed to a single steam turbine [5].

The carbon capture and storage (CCS) scenario for NGCC is the same power generation technology described in the above paragraph but is configured with a carbon capture system that recovers 90, 95, and 97 percent of the carbon dioxide (CO_2) in the flue gas. For F-Class combustion turbines, the NGCC power plant with carbon capture has the same fuel input rate as the plant without carbon capture, but the addition of a carbon capture system reduces the net power output to 645, 640, and 637 MWe, respectively. For H-Class combustion turbines, the NGCC power plant with carbon capture has the same fuel input rate as the plant without carbon capture, but the addition of a carbon capture system reduces the net power output to 883, 877, and 873 MWe, respectively [5]. In the CCS scenario, CO_2 is sent by pipeline to a saline aquifer storage site. Saline aquifers are geological formations that are saturated with brine water. In the United States (U.S.), saline aquifers have a broader geographical distribution than oil and gas reservoirs and have a large capacity potential for long-term CO_2 storage. The storage technology modeled herein comprises the energy and emissions from site preparation, well construction, CO_2 storage operations, site monitoring, brine management, well closure, and land use. It is assumed that a maximum of 1 percent of stored CO_2 eventually migrates to the surface and is released to the atmosphere over a 100-year monitoring period (a conservative assumption that is based on other NETL reports that bracket the potential storage losses until better, long-term data are available). The gate-to-grave emissions (where the gate is capture of CO_2 at a power plant and the grave is the disposition of CO_2 at a storage site) are 13.9 kg of CO_2 and 0.031 kg of methane (CH_4) per storage of one metric ton of CO_2. Small amounts of nitrous oxide (N_2O) and sulfur hexafluoride (SF_6) (accounting for less than 0.5 percent of gate-to-grave emissions) are also emitted by the CO_2 storage life cycle [6].

C.2 FLEET SCENARIOS

Each region of the United States has baseload generation capacity with load following and peaking plants that are brought online to respond to variations in demand. Demand levels rise throughout the day and are typically higher during the summer and winter than in the fall and spring [7]. When demand exceeds baseload capacity, the most efficient plants (i.e., least costly on a per-MWh basis) are typically brought online first. With each subsequent demand increase, the next most efficient plant is brought online [8].

This analysis uses the Emissions and Generation Resource Integrated Database (eGRID) [9] to characterize the heat rates and emissions from fleet power plants; however, additional filtering was necessary. The eGRID database provides regional emission profiles for natural gas power plants but does not categorize plants by application (baseload, load following, or peaking). To develop regional fleet profiles, the eGRID data were filtered by nameplate capacity, capacity factors, and heat rate. The nameplate capacity is the designed full-load sustained output, expressed in MW. The capacity factor is the ratio of annual output to maximum possible annual output. Heat rate is inverse of power plant efficiency, expressed in Btu/kWh (where 100 percent efficiency is 3,412 Btu/kWh) and, thus, potentially characterizes a plant for when it would be brought online to meet demand. The expected characteristics for natural gas plant types are categorized and shown in **Exhibit C-1**.

Exhibit C-1. Natural gas power plant characteristics

Plant Type	Capacity Factor	Heat Rate	Nameplate Capacity
Baseload	High	Low	High
Load-following	Medium	Medium	Medium/high
Peaking	Low	High	Low/medium

The 2019 natural gas baseline report [1] provides additional details pertaining to the relationships among these primary parameters (capacity factor, heat rate, and nameplate capacity) as well as the total generation for each power plant.

Using capacity factor information from the Energy Information Administration (EIA) and eGRID database as a guide [9, 10], facilities were filtered into three categories using the capacity factor ranges in **Exhibit C-2**. These ranges are subjective and are only meant to provide an informed approximation for differentiating between the baseload, load-following, and peaking natural gas plant categories in this analysis.

Exhibit C-2. Capacity factor filter for plant categorization

Plant Type	Capacity Factor
Baseload	≥ 0.6
Load-following	$0.2 \leq n < 0.6$
Peaking	< 0.2

The above capacity factors were used to filter the 2020 power plant data from eGRID, which includes power plant performance data at the facility level [9]. These data were first filtered to include facilities that had natural gas as the primary plant fuel and to exclude combined heat and power plants and plants that also processed biogas/biomass, as well as facilities with efficiencies that are outside the bounds of what is physically possible (e.g., data records where power plant efficiency is greater than 100 percent). The average efficiencies were then calculated for the three power plant types (i.e., baseload, load-following, and peaking).

Exhibit C-3 shows natural gas power plant performance for all power plant scenarios. The NGCC and NGCC w/CCS scenarios (F- and H-Class) are derived from NETL's updated 2022 baseline study [5], and the baseload, load-following, and peaking scenarios represent the filtered and stratified eGRID data. The plant nominal heat rate, plant total annual heat input, and plant annual net generation values reported to eGRID were used to estimate the power plant performance data points for baseload, load-following, and peaking plants.

Exhibit C-3. National average heat rates for natural gas power plants

Power Plant Classification	Power Plant Scenario	Net Power Plant HHV Efficiency	HHV Power Plant Heat Rate (Btu/kWh)	Feed Rate (kg/MWh)
F-Class	NGCC	53.6%	6,363	128
	NGCC w/CCS at 90% capture	47.6%	7,169	145
	NGCC w/CCS at 95% capture	47.3%	7,220	146
	NGCC w/CCS at 97% capture	47.0%	7,260	146
H-Class	NGCC	55.1%	6,196	125
	NGCC w/CCS at 90% capture	49.0%	6,959	140
	NGCC w/CCS at 95% capture	48.7%	7,007	141
	NGCC w/CCS at 97% capture	48.4%	7,045	142
Fleet Scenarios	Baseload	48.7%	7,040	137
	Load-following	45.7%	7,606	148
	Peaking	34.5%	10,677	205

C.3 Electricity Transmission and Distribution

Electricity is distributed using existing transmission and distribution infrastructure at a 7 percent loss of electrical energy during transmission and distribution [11, 12]. Additionally, SF_6 from transmission and distribution equipment is emitted at a rate of 0.143 grams of SF_6/MWh delivered [13].

C.4 CO_2 Transport and Storage

In this study, CO_2 captured at the power plant is assumed to be transported via pipeline and stored in saline aquifers. The emissions associated with the transport and storage of CO_2 are equivalent to 1.57E-02 and 1.64E-02 kg CO_2 equivalent/kg CO_2 stored on an Intergovernmental Panel on Climate Change Sixth Assessment Report 100- and 20-year global warming potential basis, respectively [14].

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Appendix D: Simulation of Liquids Unloading

D.1 Introduction

Natural gas liquids unloading is a process used to remove liquids (i.e., produced water, oil, or condensate) that may accrue in the well production tubing downhole. Accumulation of liquids in the wellbore can occur due to a variety of reasons including an increase in liquid content of the well, decreasing produced gas velocity, declining reservoir pressure, etc. [15]. The hydrostatic head created by the accumulation of liquids in the wellbore can restrict or inhibit gas flow; thus, intermittent liquids unloading is necessary to restore and maintain normal gas production. An increasing body of work suggests episodic methane (CH_4) emissions from liquids unloading events are substantial and potentially under-studied in the literature [16].

Three liquids unloading technologies are analyzed in this work: non-plunger systems, manual plunger-lift systems, and automatic plunger-lift systems. In non-plunger systems, the well operator manually vents a well to the atmosphere, a process referred to as *well blowdown*, to remove liquid build-up in the wellbore and re-establish gas flow. Plunger-lift systems utilize gas pressure buildup in the casing-tubing annulus to drive a mechanical plunger and lift the column of accumulated fluid out of the well. In *manual plunger-lift systems,* a well operator manually initiates the plunger-lift cycle, while in *automatic plunger-lift systems,* the plunger-lift cycle is automated via the use of control technologies.

This section outlines the methodology followed for estimation of throughput normalized methane emissions (TNME) stratified by extraction technology for each of the studied natural gas (NG) production basins.

D.2 Methane Emissions Estimation by Well

Emissions estimates from liquids unloading in this study use a bottom-up, process-based model previously developed by Zaimes et al. [17]. Zaimes's method is briefly summarized here. Additional details are included in the previous NG baseline report [1].

Zaimes et al. modify equations W-8 and W-9 from the Environmental Protection Agency (EPA) Greenhouse Gas (GHG) Reporting Rule in 40 CFR 98 Subpart W [18] to estimate emissions from liquids unloading from non-plunger and plunger-lift systems using **Equation D-1** and **Equation D-2**, respectively.

$$\left[{CH_4}/{well}\right]_{non-plunger} = [(V \times (0.37 \times 10^{-3}) \times CD^2 \times WD \times SP) + V \times (SFR \times (HR - 1.0) \times Z)] \times Density_{CH4} \times V_{Frac,CH4} \times Alloc_{NG}$$

Equation D-1

$$\left[{CH_4}/{well}\right]_{plunger\ lift} = [(V \times (0.37 \times 10^{-3}) \times TD^2 \times WD \times SP) + V \times (SFR \times (HR - 0.5) \times Z)] \times Density_{CH4} \times V_{Frac,CH4} \times Alloc_{NG}$$

Equation D-2

Equation D-1 and **Equation D-2** both estimate annual CH_4 emissions in units of kg CH_4/well. Key parameters used in estimating CH_4 emissions from liquids unloading are summarized in **Exhibit D-2,** where:

V = venting frequency

CD = casing diameter

TD = tubing diameter

WD = well depth

SP = shut-in pressure

SFR = standard flow rate

HR = venting duration

$Density_{CH4}$ = volumetric density of CH_4

$V_{Frac,CH4}$ = volumetric fraction of CH_4 in produced NG

$Alloc_{NG}$ = fraction of liquids unloading emissions allocated to NG activities

Data from the American Petroleum Institute (API) and America's Natural Gas Alliance (ANGA) industrial survey [19], Enverus [20], and peer-reviewed literature are used to parameterize key model inputs.

D.3 Well Filtering and Classification

Well-level data provided by Enverus [20] were filtered to retain only wells that primarily produce NG using the following criteria:

- Contains at least one of the following producer types: "GAS," "OIL," "O&G" [oil and gas], or "CBM" [coalbed methane]
- Well production occurs within the following time horizon: Jan 1, 2020, through December 31, 2020
- For producer type OIL and O&G, wells with a gas-to-oil ratio less than or equal to 100 Mcf per bbl were excluded from the analysis
- Wells with null cumulative gas production were excluded from the analysis

Wells were classified as conventional or unconventional based on producer type and drilling type, consistent with prior published literature [19]. Wells with producer type CBM were classified as unconventional; otherwise, wells were characterized based on drilling type [20]. Vertical wells were classified as conventional, while wells with drilling type "horizontal" or "directional" were flagged as unconventional. Wells of unknown type were considered conventional if the date of first gas production occurred in or prior to 2002 and otherwise classified as unconventional given when large-scale unconventional NG production became commercially viable [21].

D.4 Modeling Uncertainty and Variability

The data used to empirically estimate the parameters in **Equation D-1** and **Equation D-2** were grouped by all well types and one of each of three potential geographic groups: county, basin, or National Energy Modeling System (NEMS) region. For each parameter and well-type geography pairing represented in the data, a Monte Carlo analysis was completed in which 5,000 random samples with replacement were taken, and the resulting sample means (n = 5,000) were calculated to prepare a distribution of sample means. The resulting distribution of means were fit to either a triangular, uniform, or constant distribution using several goodness-of-fit indicators including Akaike information criteria, Bayesian information criteria, the chi-squared statistic, the Kolmogorov–Smirnov statistic, and the Anderson–Darling statistic. The following heuristics were used to choose the "best-fit" distribution, including: (1) the distribution is physically relevant; (2) the distribution is well ranked across goodness-of-fit indicators; and (3) there is precedence in the literature for using said distribution to characterize the underlying data.

Zaimes's method requires that parameters for **Equation D-1** and **Equation D-2** be estimated by county [17]; however, data were not available at the county level for all input parameters. The input distributions applied to **Equation D-1** and **Equation D-2** prioritize the finest spatial resolution available in the data. County-level distributions—the finest spatial resolution—were used if distributions could be estimated by county. For parameters without any county data, the distribution for the encompassing basin was used, if available; otherwise, the distribution for the encompassing NEMS region was used. **Exhibit D-1** provides the crosswalk between NG basins analyzed in this study and the various NEMS regions.

Exhibit D-1 Mapping of 14 NG basins to NEMS regions

Basin	Classification and Syntax (NEMS region)
Anadarko	Mid-Continent
Appalachian (160A)	Northeast
Arkla	Gulf Coast
Arkoma	Mid-Continent
East Texas	Gulf Coast
Fort Worth	Mid-Continent
Green River	Rocky Mountain
Gulf Coast	Gulf Coast
Permian	Mid-Continent
Piceance	Rocky Mountain
San Juan	Rocky Mountain
South Oklahoma	Mid-Continent
Strawn	Mid-Continent

Basin	Classification and Syntax (NEMS region)
Uinta	Rocky Mountain

D.5 Normalized Methane Emissions Estimation Method

Emissions estimated using **Equation D-1** and **Equation D-2** were summed by basin and well type, then divided by the respective total NG produced to estimate TNME as described in **Equation D-3**.

$$TNME_{basin,\ b\ and\ well\ type,\ t} = \sum_{c=1}^{\substack{counties\ in \\ b}} \frac{\left[{CH_4}/{well}\right]_{c,t} \times wells_{c,t}}{Natural\ Gas\ Produced_{c,t}}$$ ***Equation D-3***

When spatially grouping data by basin, counties were mapped to basins using a crosswalk developed by EPA [22], and NG basins were defined based on American Association of Petroleum Geologists (AAPG) geologic province codes [23, 22]. Let ($CH_{4,i,j.b}$) denote the per-well CH_4 emissions associated with liquids unloadings for basin = b and ($W_{i,j,b}$) denote the venting well count for the i^{th} liquids unloading scenario and j^{th} county in basin = b, with i = 1…6 and j = 1…n, wherein n is the number of counties in the select basin. Basin-level ($CH_{4,Basin}$) CH_4 liquids unloading emissions were calculated as the sum of the product of the per-well CH_4 emissions from liquids unloading and venting well count, over all i and j; see **Equation D-4**.

$$CH_{4,basin\,=\,b} = \sum_{i=1}^{6}\sum_{j=1}^{n} CH_{4\ i,j,b} \times W_{i,j,b}$$ ***Equation D-4***

Exhibit D-2. Key parameters in estimating NG emissions from NG liquids unloading events from non-plunger and plunger-lift systems

Parameter	Units	Data Source(s)	Data Resolution	Definition
[CH_4/well] non-plunger	kg CH_4/ year-well	Calculation	Wellhead	Annual CH_4 emissions from non-plunger systems at standard conditions
[CH_4/well] plunger	kg CH_4/ year-well	Calculation	Wellhead	Annual CH_4 emissions from plunger-lift systems at standard conditions
0.37×10^{-3}	N/A	N/A	N/A	Conversion from psia to lb/ft^2: $0.37 \times 10^{-3} = [(\pi/4) / (14.7 \text{ psi/psia} \times 144 \text{ in}^2/\text{ft}^2)]$
CD	in	Shires and Lev-On [19]; EPA [24]	Facility-level (GHGRP), or NEMS region (API/ANGA)	Well casing internal diameter. The Greenhouse Gas Reporting Program (GHGRP) provides data for well CD at the facility-level, stratified by a liquids unloading system (non-plungers, plunger lifts). A classification scheme was used to delineate data reported by GHGRP across well types (conventional, unconventional). API/ANGA provides data for well CD stratified by well type (conventional, unconventional), liquids unloading systems (non-plunger, plunger lift), and by NEMS region (Northeast, Mid-Continent, Gulf Coast, and Rocky Mountain).
TD	in	Shires and Lev-On [19]; EPA [24]	Facility-level (GHGRP), or NEMS region (API/ANGA)	Well tubing internal diameter. GHGRP provides data for well TD at the facility-level, stratified by a liquids unloading system (non-plungers, plunger lifts). A classification scheme was used to delineate data reported by GHGRP across well types (conventional, unconventional). API/ANGA provides data for well TD stratified by well type (conventional, unconventional), liquids unloading systems (non-plunger, plunger lift), and NEMS region (Northeast, Mid-Continent, Gulf Coast, and Rocky Mountain).
WD	ft	Enverus [20]	Wellhead	Well depth, obtained from Enverus
SP	psia	Shires and Lev-On [19]	NEMS region	For non-plunger systems, shut-in pressure or surface pressure for wells with tubing production and no packers or casing pressure. For plunger-lift systems, flow-line pressure for wells using engineering estimates based on best available information. API/ANGA provides data for SP stratified by well type (conventional, unconventional), liquids unloading systems (non-plunger, plunger lift), and NEMS region (Northeast, Mid-Continent, Gulf Coast, and Rocky Mountain).

Parameter	Units	Data Source(s)	Data Resolution	Definition
V	vents/ well-year	Allen et al. [25]	Wellhead	Number of vents per well per year. Allen et al. (2015) provides per-well venting frequency (V) stratified by liquids unloading systems (non-plunger, manual plunger lift, and automatic plunger lift).
SFR	scf/ hr-well	Enverus [20]	County-level	Average flow-line rate of gas per well. SFR is calculated at the county-level, derived from wellhead cumulative NG production obtained from Enverus. SFR is stratified by well type (conventional and unconventional).
HR	hr	Allen et al. [25]	Wellhead	Hours that each well was open to the atmosphere during unloading. HR stratified by liquids unloading systems (non-plunger, manual plunger lift, and automatic plunger lift) was sourced from Allen et al. [25].
1.0 =	hr	N/A	N/A	Hours for average well to blow down casing volume at shut-in pressure (applies only to non-plunger systems)
0.5 =	hr	N/A	N/A	Hours for average well to blow-down tubing volume at flow-line pressure (applies only to plunger-lift systems)
Z	N/A	N/A	N/A	Dimensionless constant. For non-plunger systems, if HR is less than 1.0, then Z is equal to 0. If HR is greater than or equal to 1.0, then Z is equal to 1. For plunger-lift systems, if HR is less than 0.5, then Z is equal to 0. If HR is greater than or equal to 0.5, then Z is equal to 1.
$Density_{CH4}$	kg CH_4/ scf-CH_4	Lemmon et al. [26]	Global	Volumetric mass density of CH_4 at standard conditions (0 °C, 1 atmosphere)—equal to 0.0203 kg NG/scf NG
VFrac,CH_4	scf CH_4/ scf NG	Lemmon et al. [26]	NEMS region	Volumetric fraction of CH_4 in NG, stratified by NEMS region (Northeast, Mid-Continent, Gulf Coast, and Rocky Mountain)
$Alloc_{NG}$	%	Calculation	Basin-level	Fraction of liquids unloading emissions apportioned to NG activities. Data are stratified by well type (conventional, unconventional), and NG basin.
HHV_{oil}	MMBtu/ bbl crude	API [27]	Global	The volumetric heating value of crude oil is assumed to be 5.8 MMBtu/bbl-crude.
HHV_{NG}	Btu/ scf NG	EIA [28]	Global	The volumetric heating value of NG is assumed to be 1,037 Btu/scf-NG.

NG is often co-produced with liquid hydrocarbons from the same well [29]; thus, allocating emissions from NG operations across the entire product slate is critical for accurate emissions attribution and for demarcating the environmental burdens between petroleum and NG supply chains. In this work, energy-based allocation is performed to apportion CH_4 emissions from liquids unloading activities across NG and co-produced oil and is defined in **Equation D-5**.

$$Alloc_{NG}\,(\%) = \frac{HHV_{NG} \times V_{NG}}{HHV_{NG} \times V_{NG} + HHV_{oil} \times V_{oil}} \quad \textit{Equation D-5}$$

In energy-based allocation, emissions are weighted across products (NG and other energy products) based on the energy content (e.g., Btu) of each product stream. The energy content of NG is calculated as the product of the volumetric energy density (HHV_{NG}) of NG, 1,037 Btu/scf-NG [28], and the volume of produced NG (V_{NG}). Similarly, the energy content of crude oil is the product of the volumetric energy density (HHV_{oil}) of crude oil, 5.8 MMBtu/bbl-crude [30], and the volume of produced crude (V_{oil}).

D.6 Standard Flow Rate

The per-well SFR of NG is estimated by converting annual 2020 natural gas production to hourly production[1] (scf/hr) and dividing by well count. SFR is disaggregated by conventional and unconventional well types and is shown in **Equation D-6.**

$$SFR = \begin{cases} Conventional = \dfrac{Conventional\ NG\ Production(\frac{scf}{year})}{Conventional\ Well\ Count\ (\#\ wells)} \times (\dfrac{year}{8784\ hrs}) \\ Unconventional = \dfrac{Unconventional\ NG\ Production(\frac{scf}{year})}{Unconventional\ Well\ Count\ (\#\ wells)} \times (\dfrac{year}{8784\ hrs}) \end{cases} \quad \textit{Equation D-6}$$

D.7 Venting Well Counts

It is important to note that not all non-plunger and plunger-lift-equipped wells vent to the atmosphere; thus, wells that vent represent a sub-set of total well count. The liquids unloading scenarios evaluated in this work represent only wells that vent to the atmosphere, including those with and without plungers and both manual and automatic plunger lifts.

The venting well count ($W_{i,j}$) for the *I^th^* scenario and *j^th^* county is calculated as the product of the county-level well count ($W_{DI,County}$) obtained from Enverus [20] and fraction of non-plunger, manual plunger-lift, or automatic plunger-lift wells that vent for liquids unloading ($F_{venting}$) derived from data reported by EPA [24]. It is important to note that $F_{venting}$ is calculated at the county-level ($F_{venting,County}$); however, in instances in which county-level data are unavailable or

[1] There are 8,760 hours in a typical calendar year (365) days; however, 2020 was a leap year (366 days), and hence a conversion factor of 8,784 hours/year is used in this analysis.

not reported, F_{vent} is derived at the basin level ($F_{venting,Basin}$). The calculation of venting well count (Wi,j) is shown in **Equation D-7**.

$$W_{i,j} = W_{DI,County} \times F_{venting}$$ ***Equation D-7***

County-level well counts ($W_{DI,County}$) are obtained from Enverus [20] and stratified across well types. Data from EPA [24] are used to estimate the fraction of wells that vent for liquids unloading ($F_{venting}$) for non-plunger, manual plunger lift, and automatic plunger lifts. A detailed workflow for calculating the fraction of wells that vent for liquids unloading at the county level is summarized in Zaimes et al. and Littlefield et al. [17, 1].

A summary of all onshore wells for which emissions are reported is publicly available via the dataset “EF_W_ONSHORE_WELLS” [31]. In this work, onshore NG wells reported by EPA [24] are matched to NG basins based on AAPG Geologic Provinces Codes. Wells with formation type “Coal seam” and “Shale gas” are considered unconventional, while wells with formation type “High permeability gas,” “Oil,” and “Other tight reservoir rock” are considered conventional.

EPA [24] provides a detailed summary of wells that vent for liquids unloading in the dataset “EF_W_LIQUIDS_UNLOAD_UNITS” [32]. In this work, facilities that vent for liquids unloading with formation type “Coal seam” and “Shale gas” are classified as unconventional, while facilities with formation type “High permeability gas,” “Oil,” and “Other tight reservoir rock” are considered conventional. Additionally, EPA [24] reports the number of non-plunger and plunger-lifts wells that vent for liquids unloading at the facility level; however, EPA [24] does not distinguish between venting manual or automatic plunger-lift wells. This work estimates the number of automatic and manual plunger-lift systems for each facility well-type pair, using EPA [24] data as model constraints.

The following approach is used to disaggregate facility-level venting plunger-lift well count, reported by EPA [24], into venting automatic and manual plunger-lift well counts, where:

X	= venting automatic plunger-lift well count
Y	= venting manual plunger-lift well count
Z	= venting plunger-lift well count, as reported by EPA [24]
V	= average liquids unloading event count, as reported by EPA [24]
Vf_{auto}	= per-well venting frequency for automatic plunger lifts
Vf_{manual}	= per-well venting frequency for manual plunger lifts

It is assumed that the facility-level venting plunger-lift well count (Z), reported by EPA [24], is composed of (X) venting automatic plunger lifts and (Y) manual plunger-lift wells; see **Equation D-8**.

$$X + Y = Z$$ ***Equation D-8***

The average liquid unloading event count (V), as reported by EPA [24], is thus a linear combination of per-well venting frequency (Vf_{auto}, Vf_{manual}) and well count (X, Y) for automatic and manual plunger lifts, respectively; see **Equation D-9**, **Equation D-10**, and **Equation D-11**.

$$Vf_{auto}(X) + Vf_{manual}(Y) = V$$ ***Equation D-9***

Substitute for Y, to yield:

$$Vf_{auto}(X) + Vf_{manual}(Z - X) = V$$ ***Equation D-10***

Solving for X yields:

$$X = \frac{V - (Vf_{manual} \times Z)}{Vf_{auto} - Vf_{manual}}$$ ***Equation D-11***

It is important to note, however, that this approach produces erroneous results if $(Vf_{manual} \times Z) > V$ or if $V > (Vf_{auto} \times Z)$. As such, the following conditions are applied to estimate the fraction of venting manual and automatic plunger-lift wells: if $(Vf_{manual} \times Z) > V$, then all wells are assumed to be manual plunger lifts (i.e., Y=Z); if $V > (Vf_{auto} \times Z)$, then all wells are assumed to be automatic plunger lifts (i.e., X=Z); if $(Vf_{auto} \times Z) > V > (Vf_{manual} \times Z)$, X and Y are calculated via **Equation D-12**. In this approach, variability in the venting frequency for manual and automatic plunger lifts is propagated into variability in venting automatic well count (X) and venting manual well count (Y).

$$If \begin{cases} Vf_{manual} \times Z > V, & X = 0, & Y = Z \\ Vf_{auto} \times Z > V > Vf_{manual} \times Z, & X = Round\left(\frac{V - (Vf_{manual} \times Z)}{Vf_{auto} - Vf_{manual}}\right), & Y = Z - X \\ V > Vf_{auto} \times Z, & X = Z, & Y = 0 \end{cases}$$ ***Equation D-12***

Venting well count reported by EPA [24] or GHGRP, stratified by well type and liquids unloading system, is aggregated at both the county level ($W_{vent,\ GHGRP,\ County}$) and basin level ($W_{vent,GHGRP,Basin}$) and used to derive county-level ($F_{vent,County}$) and basin-level venting well fractions ($F_{vent,Basin}$), respectively.

County-level venting well counts ($W_{i,j}$) for non-plunger, manual plunger-lift, and automatic plunger-lift systems are constructed by applying venting well fractions (F_{vent}) derived from EPA [24] to county-level well count ($W_{Enverus,\ County}$) obtained from Enverus [20]. If there is a direct match in county well-type pairs in these references, then county-level venting well fractions are applied ($F_{vent,County}$); otherwise, basin-level venting well fractions ($F_{vent,Basin}$) are applied. There is no variability within the venting well count for non-plunger systems, as they are based on static values reported to EPA [24]. Variability in venting well count for automatic and manual plunger-lift systems arises from disaggregating the plunger-lift category from EPA [24], as described in **Equation D-12**.

D.8 Diameter, Depth, and Pressure Parameters

EPA [24] provides average values for well parameters (CD, TD, WD, and SP) reported at the facility-level with sparse entries for well depth or shut-in pressure. In this work, facility-level data for casing diameter and tubing diameter reported by EPA [24] are mapped to county-level data reported by Enverus [20]. Triangular distributions for well CD and well TD are constructed at the county level by considering the minimum, maximum, and expected value (venting well weighted average) across all facilities that lie within said county. In cases where there is no direct mapping between facility-level data reported in EPA [24] and county-level data obtained from Enverus [20], basin-wide minimum, maximum, and expected values are used to parameterize the triangular distribution(s).

In this work, data from the API/ANGA 2012 industrial survey are used to fill data gaps that may arise in EPA [24, 19]. API/ANGA reports data for well CD, TD, depth, and shut-in pressure, across five NEMS regions (Northeast, Gulf Coast, Mid-Continent, Southwest, and Rocky Mountain), two well types (conventional and unconventional), and two broad liquids unloading technologies (non-plunger, plunger-lift systems). Triangular distributions are used to characterize well CD, TD, WD, and SP, based on min, max, and expected values (venting well weighted average).

API/ANGA disaggregates well casing and tubing diameter by well type (conventional, unconventional) and geospatially across five NEMS regions (Northeast, Gulf-Coast, Mid-Continent, Southwest, and Rocky Mountain). API/ANGA disaggregates well depth by liquids unloading technology (non-plunger, plunger-lift), well type (conventional, unconventional), and geospatially across five NEMS regions (Northeast, Gulf-Coast, Mid-Continent, Southwest, and Rocky Mountain). API/ANGA disaggregates well shut-in pressure by liquids unloading technology (non-plunger, plunger lift), well type (conventional, unconventional), and geospatially across five NEMS regions (Northeast, Gulf-Coast, Mid-Continent, Southwest, and Rocky Mountain). The API/ANGA survey reports shut-in pressure (psig) in units of psi [19]. Shut-in pressure is converted from psig to psia via the addition of atmospheric pressure (14.7 psi).

D.9 VOLUMETRIC FRACTION OF METHANE IN NATURAL GAS

The volumetric fraction of CH_4 in produced NG ($V_{Frac,CH4}$) is stratified by NEMS region. It is assumed that the composition of NG is dependent on the geographic region but invariant to the liquids unloading technology. Data from Allen et al. [25] are used to parameterize the volumetric fraction of CH_4 in NG across NEMS regions; expected values for $V_{Frac,CH4}$ are calculated as the average over each NEMS region (e.g., Northeast, Gulf Coast, Mid-Continent, Rocky Mountain).

D.10 RESULTS

The simulated mean TNME from NG liquids unloading in 2020 is provided in **Exhibit D-3**. Results are stratified by conventional and unconventional well type.

Exhibit D-3. Mean TNME from NG liquids unloading

Basin	Conventional		Unconventional	
	Mean TNME	95% CI in the Mean	Mean TNME	95% CI in the Mean
Anadarko	0.158%	(0.155%, 0.160%)	0.025%	(0.024%, 0.026%)
Appalachian	--	--	0.069%	(0.067%, 0.072%)
Arkla	0.053%	(0.051%, 0.054%)	0.064%	(0.059%, 0.069%)
Arkoma	0.455%	(0.447%, 0.463%)	0.133%	(0.131%, 0.136%)
East Texas	0.076%	(0.072%, 0.079%)	0.046%	(0.044%, 0.048%)
Fort Worth	--	--	0.101%	(0.096%, 0.105%)
Green River	0.059%	(0.056%, 0.062%)	--	--
Gulf Coast	0.041%	(0.038%, 0.043%)	0.030%	(0.029%, 0.030%)
Permian	0.004%	(0.003%, 0.004%)	--	--
Piceance	--	--	0.047%	(0.044%, 0.049%)
San Juan	--	--	0.031%	(0.030%, 0.032%)
South Oklahoma	--	--	0.014%	(0.014%, 0.015%)
Strawn	--	--	0.017%	(0.015%, 0.018%)
Uinta	0.101%	(0.095%, 0.106%)	--	--
Aggregate	0.263%	(0.256%, 0.269%)	0.053%	(0.052%, 0.055%)

Please note that the Python script and intermediate data used for generating the 2020 TNME from liquids unloading are available in the release package published along with this report.

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APPENDIX E: DETAILED GHG RESULTS FOR ALL SCENARIOS

Excel files in the release package published along with this report provide the detailed greenhouse gas (GHG) results for all scenarios across the 29 techno-basins, 7 downstream regional scenarios, and 2 boundary scopes.

The package contains six folders providing results for two different system boundaries, across three sets of global warming potential (GWP) values (Intergovernmental Panel on Climate Change [IPCC] Fourth, Fifth, and Sixth Assessment Report):

1. Production through Distribution boundary

   Functional Unit: 1 MJ of natural gas delivered to consumers through distribution network (includes combination of residential, commercial, industrial, and power sectors)

2. Production through Transmission Network boundary

   Functional Unit: 1 MJ of natural gas delivered directly to end users via transmission pipeline (typically includes industrial and power sectors)

As listed below, within each folder are eight Excel files that provide detailed GHG results for all the feasible scenarios (see **Appendix H: Scenario Map of Modeled Upstream Techno-basins and Downstream Delivery Regions**) based on each of the seven downstream regional scenarios, and a regional results summary file. The "ARX" in the filename is replaced by the specific set of GWP values used from the IPCC Fourth, Fifth or Sixth Assessment Report (e.g., AR4, AR5, or AR6).

LIST OF FILES

PRODUCTION THROUGH DISTRIBUTION RESULTS

1. **2020 Drilldown Results_US Avg_ARX:** Detailed GHG Results for All Scenarios – Production through Distribution Boundary – using U.S. Average Transmission Network through Distribution data
2. **2020 Drilldown Results_Midwest_ARX:** Detailed GHG Results for All Scenarios – Production through Distribution Boundary – using Midwest Transmission Network through Distribution data
3. **2020 Drilldown Results_Northeast_ARX:** Detailed GHG Results for All Scenarios – Production through Distribution Boundary – using Northeast Transmission Network through Distribution data
4. **2020 Drilldown Results_Pacific_ARX:** Detailed GHG Results for All Scenarios – Production through Distribution Boundary – using Pacific Transmission Network through Distribution data
5. **2020 Drilldown Results_Rocky Mountain_ARX:** Detailed GHG Results for All Scenarios – Production through Distribution Boundary – using Rocky Mountain Transmission Network through Distribution data

6. **2020 Drilldown Results_Southeast_ARX:** Detailed GHG Results for All Scenarios – Production through Distribution Boundary – using Southeast Transmission Network through Distribution data
7. **2020 Drilldown Results_Southwest_ARX:** Detailed GHG Results for All Scenarios – Production through Distribution Boundary – using Southwest Transmission Network through Distribution data
8. **2020 Regional Results Summary_PTD_ARX:** Provides GHG Results Summary on a 20-yr and 100-yr GWP basis for all Regional Scenarios, Production through Distribution Boundary

PRODUCTION THROUGH TRANSMISSION NETWORK RESULTS

9. **2020 Drilldown Results_US Avg_ProdThruTrans_ARX:** Detailed GHG Results for All Scenarios – Production through Transmission Network Boundary – using U.S. Average Transmission Network data
10. **2020 Drilldown Results_Midwest_ProdThruTrans_ARX:** Detailed GHG Results for All Scenarios – Production through Transmission Network Boundary – using Midwest Transmission Network data
11. **2020 Drilldown Results_Northeast_ProdThruTrans_ARX:** Detailed GHG Results for All Scenarios – Production through Transmission Network Boundary – using Northeast Transmission Network data
12. **2020 Drilldown Results_Pacific_ProdThruTrans_ARX:** Detailed GHG Results for All Scenarios – Production through Transmission Network Boundary – using Pacific Transmission Network data
13. **2020 Drilldown Results_Rocky Mountain_ProdThruTrans_ARX:** Detailed GHG Results for All Scenarios – Production through Transmission Network Boundary – using Rocky Mountain Transmission Network data
14. **2020 Drilldown Results_Southeast_ProdThruTrans_ARX:** Detailed GHG Results for All Scenarios – Production through Transmission Network Boundary – using Southeast Transmission Network data
15. **2020 Drilldown Results_Southwest_ProdThruTrans_ARX:** Detailed GHG Results for All Scenarios – Production through Transmission Network Boundary – using Southwest Transmission Network data
16. **2020 Regional Results Summary_PTT_ARX:** Provides GHG Results Summary on a 20-yr and 100-yr GWP basis for all Regional Scenarios, Production through Transmission Network Boundary

Appendix F: Full Inventory Results

Excel files in the release package published along with this report provide the full inventory results for all scenarios across the 29 techno-basins, 7 downstream regional scenarios, and 2 boundary scopes.

The package contains two folders providing results for two different system boundaries:

1. Production through Distribution boundary

   Functional Unit: 1 MJ of natural gas delivered to consumers through distribution network (includes mix of residential, commercial, industrial, and power sectors)

2. Production through Transmission Network boundary

   Functional Unit: 1 MJ of natural gas delivered directly to end users via transmission pipeline (typically includes industrial and power sectors)

As listed below, within each folder are seven Excel files that provide full inventory results for all the feasible scenarios (see **Appendix H: Scenario Map**) based on each on the seven downstream regional scenarios.

List of Files

Production through Distribution Results

1. **2020 Full Inventory Results_US Avg:** Full Inventory Results – Production through Distribution Boundary – using U.S. Average Transmission Network through Distribution data
2. **2020 Full Inventory Results_Midwest:** Full Inventory Results – Production through Distribution Boundary – using Midwest Transmission Network through Distribution data
3. **2020 Full Inventory Results_Northeast:** Full Inventory Results – Production through Distribution Boundary – using Northeast Transmission Network through Distribution data
4. **2020 Full Inventory Results_Pacific:** Full Inventory Results – Production through Distribution Boundary – using Pacific Transmission Network through Distribution data
5. **2020 Full Inventory Results_Rocky Mountain:** Full Inventory Results – Production through Distribution Boundary – using Rocky Mountain Transmission Network through Distribution data
6. **2020 Full Inventory Results_Southeast:** Full Inventory Results – Production through Distribution Boundary – using Southeast Transmission Network through Distribution data
7. **2020 Full Inventory Results_Southwest:** Full Inventory Results – Production through Distribution Boundary – using Southwest Transmission Network through Distribution data

Production through Transmission Network Results

8. **2020 Full Inventory Results_US Avg_ProdThruTrans:** Full Inventory Results – Production through Transmission Network Boundary – using U.S. Average Transmission Network data

9. **2020 Full Inventory Results_Midwest_ProdThruTrans:** Full Inventory Results – Production through Transmission Network Boundary – using Midwest Transmission Network data
10. **2020 Full Inventory Results_Northeast_ProdThruTrans:** Full Inventory Results – Production through Transmission Network Boundary – using Northeast Transmission Network data
11. **2020 Full Inventory Results_Pacific_ProdThruTrans:** Full Inventory Results – Production through Transmission Network Boundary – using Pacific Transmission Network data
12. **2020 Full Inventory Results_Rocky Mountain_ProdThruTrans:** Full Inventory Results – Production through Transmission Network Boundary – using Rocky Mountain Transmission Network data
13. **2020 Full Inventory Results_Southeast_ProdThruTrans:** Full Inventory Results – Production through Transmission Network Boundary – using Southeast Transmission Network data
14. **2020 Full Inventory Results_Southwest_ProdThruTrans:** Full Inventory Results – Production through Transmission Network Boundary – using Southwest Transmission Network data

Please note that the Appendix F Excel files contain hidden tabs with background data pulled directly from the National Energy Technology Laboratory natural gas model. These hidden tabs can be accessed by right-clicking on any of the available tabs and clicking on the “Unhide” option.

Appendix G: Production Share Estimation Methodology

As part of an effort to move toward use of publicly available data to ensure transparency, this work relies on the Environmental Protection Agency (EPA)'s Greenhouse Gas Reporting Program (GHGRP) and Energy Information Administration (EIA) data for estimating 2020 natural gas (NG) production shares for the 29 onshore and offshore scenarios that are used to generate weighted-average national and regional emissions profiles. GHGRP provides NG volumes from onshore gas production, while offshore gas production volumes are obtained from EIA.

GHGRP data provide the number of producing wells by formation type (high permeability gas or conventional, tight, shale, oil, and CBM), and NG produced for sales[1] for each GHGRP reporting facility. This section uses the terms "formation type" and "well type" interchangeably. **Exhibit G-1** summarizes the GHGRP and EIA data used for estimating NG production shares.

Exhibit G-1. GHGRP and EIA data summary for production share estimation

Production Type	Data	Reporting Level	Data Source
Onshore gas production	NG produced for sales	Facility level	GHGRP SubPart W - EF_W_FACILITY_OVERVIEW [33]
	Number of producing wells	Facility level, broken down by well or formation type	
	Basin identifier	Facility level	
Offshore gas production	NG marketed production	State level	EIA NG Marketed Production [34]

G.1 Use of GHGRP Data for Production Share Estimation

GHGRP data are used for estimating techno-basin-level NG production volumes (and eventually production shares) for all 27 onshore gas production scenarios modeled in this work. A single GHGRP production facility[2] can represent multiple well types, and NG production volumes are only reported at the facility level (not broken down by well or formation type). Hence, assumptions need to be made for generating production shares for each techno-basin scenario (combination of basin and formation type) modeled in this work. This methodology assigns associated gas production volumes (i.e., gas produced from oil wells) from various facilities to other non-oil formation types, as oil wells can represent production from any well technology (conventional or unconventional) that co-produces NG and oil. Unlike previous National Energy

[1] Since GHGRP does not provide a clear definition for "NG produced for sales," it is assumed to refer to marketed NG production in this work. Marketed NG production is defined by EIA as "gross withdrawals of natural gas from production reservoirs, less gas used for reservoir repressuring, nonhydrocarbon gases removed in treating and processing operations, and quantities vented and flared" [37].

[2] As noted in **Section 3.3.1**, a production facility refers to all petroleum or NG equipment on a single well pad or associated with a single well pad and CO_2 enhanced oil recovery operations that are under common ownership or common control including leased, rented, or contracted activities by an onshore petroleum and NG production owner or operator and that are located in a single hydrocarbon basin. Where a person or entity owns or operates more than one well in a basin, then all onshore petroleum and NG production equipment associated with all wells that the person or entity owns or operates in the basin would be considered one facility [38].

Technology Laboratory NG modeling, associated gas production is not modeled as a separate profile in this work; instead, these volumes are embedded under existing techno-basin categories. This modeling change helps ensure consistency and transparency in the use of data sources for estimating production shares and emissions profiles. The various steps involved in the estimation of NG production volumes at the facility level (and eventually aggregated to basin level) by well type are outlined below.

- Based on GHGRP reporting, generate proportions of producing wells by formation type at each production facility.
- For facilities with no oil-type wells, the NG produced for sales volumes are directly allocated among the various formation types based on the proportion of producing wells.
- For facilities with oil-type wells (i.e., facilities producing associated gas), the NG produced for sales volumes are allocated among the other non-oil formation types as follows:
    - If the facility reports wells under other formation types, the NG produced for sales volumes from the facility are initially allocated based on the proportion of producing wells by formation type. Finally, all NG produced for sales volumes falling under oil formation type are allocated to the reported non-oil formation types at that facility, based on the share of non-oil formation types. This assumes that all oil-type wells reported under this facility can be represented by the mix of other well types at the same facility.
    - If the facility does not report any wells under other formation types (i.e., 100 percent of producing wells classified as oil), the NG produced for sales volumes from the facility are allocated to the non-oil formation types, based on the basin-level average producing-well share of non-oil formation types. The assumption here is that this facility's oil wells can be represented by the mix of technologies used in the basin.

Exhibit G-2 highlights the production volume estimation process with the help of a few sample production facilities representing different scenarios. For facility 1, the NG produced for sales volume is allocated among the various formation types based on the proportion of producing well type. For facility 2, 84 percent of the wells are classified as conventional and the remaining 16 percent are classified as oil. As a result, the total NG produced for sales volume at this facility is assigned to the conventional formation type, with 84 percent allocated from the conventional formation type itself and 16 percent allocated from the oil formation type. For facility 3, an initial classification involves allocating NG produced for sales volumes among the various well types available at the facility based on the producing well share (60 percent oil, 21 percent conventional, and 19 percent shale). The final classification involves assigning the NG produced for sales volumes under the oil formation type to the conventional and shale categories, based on the producing-well share of non-oil formation types at that facility (i.e., 52 percent conventional and 48 percent shale). Finally, for facility 4, all wells are classified as oil, and hence the total NG produced for sales volume at the facility is initially classified under the oil formation type; however, the final classification involves assigning the NG produced for sales volumes under the oil formation type to the various non-oil formation type categories, based on the producing well share of non-oil formation types at the basin level (estimated to be 68 percent conventional, 21 percent shale, and 10 percent tight). It is worth noting that GHGRP reports the associated basin for each facility; however, this detail is not provided explicitly in **Exhibit G-2**.

Exhibit G-3 provides the final total estimated production volumes for each of the onshore NG production basins studied in this work, broken down by well or formation type, based on the methodology described above.

Exhibit G-2. NG production volume estimation results for sample production facilities

Facility	NG Produced for Sales (Mcf/yr)	Producing Wells Proportion					Facility Classification[a]	Production Volumes by Formation Type (Mcf/yr)					Classification Type[a]
		CBM	Conv	Oil	Tight	Shale		CBM	Conv	Oil	Tight	Shale	
Facility 1	1.66E+08	1%	28%	0%	66%	6%	Allocated to Tight, Conv, Shale, and CBM	1.07E+06	4.60E+07	0.00E+00	1.10E+08	9.32E+06	Final
Facility 2	3.34E+07	0%	84%	16%	0%	0%	Conv	0.00E+00	3.34E+07	0.00E+00	0.00E+00	0.00E+00	Final
Facility 3	3.67E+06	0%	21%	60%	0%	19%	Oil	0.00E+00	7.61E+05	2.21E+06	0.00E+00	6.92E+05	Initial
		0%	52%	0%	0%	48%	Allocated to Conv and Shale[b]	0.00E+00	1.92E+06	0.00E+00	0.00E+00	1.75E+06	Final
Facility 4	1.71E+07	0%	0%	100%	0%	0%	Oil	0.00E+00	0.00E+00	1.71E+07	0.00E+00	0.00E+00	Initial
		0%	68%	0%	10%	21%	Allocated to Conv, Tight, and Shale[c]	0.00E+00	1.17E+07	0.00E+00	1.75E+06	3.67E+06	Final

[a] The Facility Classification and Classification Type columns are provided here for illustrative purposes, GHGRP does not report these details. The Facility Classification is based on number of producing wells at that facility (or basin), as reported to GHGRP.
[b] Based on non-oil formation mix at facility
[c] Based on non-oil formation mix at basin

Exhibit G-3. Estimated NG production for sales volumes by well type and geography

Techno-basin	NG Produced for Sales (Mcf/yr)			
	CBM	Conv	Tight	Shale
Anadarko	-	5.14E+08	5.34E+08	7.43E+08
Appalachian[a, b]	-	-	-	1.09E+10
Arkla	-	9.29E+08	2.53E+08	1.63E+09
Arkoma[b]	-	1.55E+08	-	4.95E+08
East Texas	-	2.28E+08	1.06E+09	1.98E+08
Fort Worth[b]	-	-	-	2.49E+08
Green River	-	1.74E+07	7.43E+08	-
Gulf Coast	-	7.67E+08	2.17E+08	9.90E+08
Permian[b]	-	2.75E+09	-	1.99E+09
Piceance[b]	-	-	5.27E+08	-
San Juan[b]	2.63E+08	-	-	3.03E+08
South Oklahoma[b]	-	-	-	2.67E+08
Strawn[b]	-	-	-	4.27E+08
Uinta	-	7.16E+06	1.66E+08	-

[a] The Appalachian techno-basin scenario modeled in this work represents aggregated GHGRP-reported data for Appalachian basin 160 and Appalachian basin 160A (Eastern Overthrust).
[b] These basins represent aggregated shale and tight production volumes classified under either the shale or tight category (depending on the basin), to limit the number of scenarios modeled in this work.

G.2 Use of EIA Data for Production Share Estimation

EIA data [34] are used for estimating NG production volumes (and eventually production shares) for the two offshore gas production scenarios modeled in this work. **Exhibit G-4** provides the NG marketed production volumes for the Gulf of Mexico (GoM) and Alaska offshore scenarios used in this work for estimating the final techno-basin level production shares.

Exhibit G-4. EIA NG marketed production for offshore NG production scenarios

Scenario	2020 NG Marketed Production (Mcf/yr)	Relevant EIA Category
GoM Offshore	3.85E+07	Federal Offshore Gulf of Mexico
Alaska Offshore	7.91E+08	Alaska State Offshore

G.3 Final NG Production Shares by Techno-basin

Exhibit G-5 provides the U.S. average gas production shares estimated using GHGRP and EIA data provided in **Exhibit G-3** and **Exhibit G-4**, for the various techno-basin scenarios studied in this work.

Exhibit G-5. Estimated U.S. average gas production shares by well type and basin

Techno-basin	Production Share
Alaska – offshore	0.14%
Anadarko – conv	1.83%
Anadarko – shale	2.64%
Anadarko – tight	1.90%
Appalachian – shale	38.68%
Arkla – conv	3.30%
Arkla – shale	5.78%
Arkla – tight	0.90%
Arkoma – conv	0.55%
Arkoma – shale	1.76%
East Texas – conv	0.81%
East Texas – shale	0.70%
East Texas – tight	3.78%
Fort Worth – shale	0.89%
GoM – offshore	2.81%
Green River – conv	0.06%
Green River – tight	2.64%
Gulf – conv	2.72%
Gulf – shale	3.52%
Gulf – tight	0.77%
Permian – conv	9.76%
Permian – shale	7.09%
Piceance – tight	1.87%
San Juan – CBM	0.93%
San Juan – shale	1.08%
South Oklahoma – shale	0.95%
Strawn – shale	1.52%
Uinta – conv	0.03%
Uinta – tight	0.59%

G.4 Comparison with EIA Reported Data

As a data validation exercise, the production shares estimated using data from GHGRP (for the 27 onshore gas production scenarios) and EIA (for the 2 offshore gas production scenarios) are compared with production shares generated using state-level EIA-reported marketed production volumes, as shown in **Exhibit G-6**. This was achieved by approximately mapping state-level EIA data to the various gas production basins based on their geographical location.

Exhibit G-6. Comparison of production shares between this work and EIA data

Basin(s)	Estimated Production Share (Current Report)	Proxy EIA State	EIA Production Share as Proportion of Total U.S. Marketed Production
Appalachian	38.68%	Pennsylvania, West Virginia, Ohio, New York	33.23%
Permian, Gulf Coast, East Texas, Fort Worth, Strawn, San Juan	33.58%	Texas, New Mexico	32.24%
Green River, Uinta, Piceance	5.19%	Utah, Colorado, Wyoming	9.43%
Anadarko, Arkla, Arkoma, South Oklahoma	19.60%	Louisiana, Oklahoma, Kansas, Arkansas	17.80%
GoM Offshore	2.81%	Federal GoM Offshore	2.17%
Alaska Offshore	0.14%	Alaska State Offshore	0.11%

In general, the production shares estimated in this work are reasonably aligned with EIA reporting, with some basins being higher or lower. However, some reasons for the observed discrepancy in production shares include: (1) difference in coverage between GHGRP and EIA data due to the reporting threshold associated with GHGRP reporting; (2) consideration of major but not all gas production basins in this work, while EIA accounts for total U.S. marketed production volumes; and (3) inaccurate mapping of basin-level GHGRP reporting to state-level EIA data.

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Appendix H: Scenario Map of Modeled Upstream Techno-basins and Downstream Delivery Regions

Exhibit H-1 provides a summary map of all scenarios analyzed in this study, linking upstream production basins to downstream delivery regions.

Exhibit H-1. Scenario map linking upstream production techno-basins to downstream delivery regions

← Upstream Scenarios / Downstream Regions → Techno-basin	Pacific	Rocky Mountain	Southwest	Southeast	Midwest	Northeast	U.S. Average
Appalachian – shale	-	-	-	9.59%	46.50%	87.72%	38.68%
Gulf – conv	-	-	6.15%	3.28%	2.10%	0.82%	2.72%
Gulf – shale	-	-	7.93%	4.24%	2.72%	1.06%	3.52%
Gulf – tight	-	-	1.74%	0.93%	0.60%	0.23%	0.77%
Arkla – conv	-	-	-	9.08%	-	-	3.30%
Arkla – shale	-	-	-	15.90%	-	-	5.78%
Arkla – tight	-	-	-	2.47%	-	-	0.90%
East Texas – conv	-	-	1.83%	0.98%	0.63%	0.24%	0.81%
East Texas – shale	-	-	1.59%	0.44%	0.52%	0.21%	0.70%
East Texas – tight	-	-	8.53%	4.56%	2.92%	1.14%	3.78%
Arkoma – conv	-	-	-	1.52%	-	-	0.55%
Arkoma – shale	-	-	-	4.84%	-	-	1.76%
South Oklahoma – shale	-	-	2.14%	1.14%	0.73%	0.29%	0.95%
Anadarko – conv	-	-	4.12%	2.20%	1.41%	0.55%	1.83%
Anadarko – shale	-	-	5.95%	3.18%	2.04%	0.79%	2.64%
Anadarko – tight	-	-	4.28%	2.29%	1.47%	0.57%	1.90%
Strawn – shale	-	-	3.42%	1.83%	1.17%	0.46%	1.52%
Fort Worth – shale	-	-	2.00%	1.07%	0.68%	0.27%	0.89%
Permian – conv	-	-	22.02%	11.76%	7.54%	2.93%	9.76%
Permian – shale	-	-	15.99%	8.54%	5.48%	2.13%	7.09%
Green River – conv	1.19%	1.19%	0.09%	-	0.26%	-	0.06%
Green River – tight	50.84%	50.84%	3.95%	-	11.15%	-	2.64%
Uinta – conv	0.49%	0.49%	0.04%	-	0.11%	-	0.03%
Uinta – tight	11.39%	11.39%	0.88%	-	2.50%	-	0.59%
San Juan – CBM	-	-	2.11%	1.13%	0.72%	0.28%	0.93%
San Juan – Shale	-	-	2.43%	1.30%	0.83%	0.32%	1.08%
Piceance – tight	36.09%	36.09%	2.80%	-	7.92%	-	1.87%
Alaska – offshore	-	-	-	-	-	-	0.14%
GoM – offshore	-	-	-	7.74%	-	-	2.81%
Associated gas	-	-	-	-	-	-	-
Total	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**	**100%**

Note: The Pacific and Rocky Mountain regions have the same delivery proportions in the above exhibit since both these regions receive gas from the same upstream production techno-basins.

The percentages in **Exhibit H-1** depict the proportion of natural gas (NG) delivered to a downstream delivery region from various upstream production techno-basins. These basin-level delivery proportions were estimated using work by Littlefield et al. [35], which created state-level NG production and delivery pairings using NG consumption data from EIA [36]. These state-level pairings were aggregated to the regional level, and, using production shares of each production techno-basin (see **Exhibit 2-3**), the proportion of NG delivered to a downstream region by each of the techno-basins was estimated.

APPENDIX I: STAGE-LEVEL NATURAL GAS LOSS AND CONSUMPTION RATES

The Appendix I Excel file in the release package published along with this report provides the stage-level natural gas loss and consumption rates for each scenario analyzed in this study (as highlighted in **Appendix H: Scenario Map of Modeled Upstream Techno-basins and Downstream Delivery Regions**).

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