Gas Index Model (GIM) documentation

Version 1.0 (December 2, 2020)

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1. Units, conversion factors, and definitions

Gas volumes are normally reported in cubic feet, in keeping with the practice by the U.S. Energy Information Administration (EIA) and the U.S. oil and gas industry. All volumes are for standard conditions (60 °F, 14.73 psia).

Scf = standard cubic feet. Mcf = thousand cubic feet; MMcf = million cubic feet; Bcf = billion cubic feet. For SI units, Bcm = billion cubic meters.

There are 35.315 scf per cubic meter (m^3). Systems that do not operate at standard conditions, including compressed natural gas (CNG), liquefied natural gas (LNG) operations, and other natural gas assets, are noted.

Energy quantities are reported in British thermal units (Btu), in keeping with EIA practice. MMbtu = million Btu.

All tons reported here are metric tons. Emissions are reported in metric units, in keeping with EPA practice in the Greenhouse Gas Inventory. In citing results from other studies, other units of mass are sometimes used. Gg = gigagrams; Tg = teragrams. We note that 1 Gg = 1,000 metric tons; 1 Tg = 1,000,000 metric tons.

The documentation uses the term "gross gas" to refer to the total gas produced at the wellhead, following the practice of the EIA, which reports gross gas production volumes prior to any processing, and that include natural gas liquids (NGLs). This stream of gross gas is also referred to in some settings as "wet gas" (if it contains a large fraction of NGLs), or as "raw gas."

Dry gas is also considered consumer-grade gas, which EIA defines as "natural gas which remains after: 1) the liquefiable hydrocarbon portion has been removed from the gas stream (i.e., gas after lease, field, and/or plant separation); and 2) any volumes of nonhydrocarbon gases have been removed where they occur in sufficient quantity to render the gas unmarketable."

GIM converts methane emission volumes to masses using the density of methane under standard conditions, 1 cubic foot = 0.0193 kg (EPA 2020c).

NG is sometimes used as an abbreviation for "natural gas." We also use "fossil gas" as a synonym for natural gas.

Methane leakage for production areas is calculated relative to gross gas volumes extracted in a given area. Then using an energy-based allocation, methane leakage from production areas is allocated to dry gas produced in each production area, to then yield a leakage rate relative to dry gas volumes (in terms of g methane leaked per Mcf dry gas). For all subsequent steps in the gas delivery system (transmission, distribution, customer gas meters, and behind-the-meter), leakage is calculated relative to dry gas volumes (in terms of g methane leaked per Mcf dry gas).

2. Overview

The Gas Index Model (GIM) estimates life cycle greenhouse gas (GHG) emissions due to natural gas consumed in the contiguous U.S. The primary focus is on more accurate accounting of methane leakage from the gas system, and granular data on the life cycle methane leakage for gas consumed in various U.S. cities.

First, GIM estimates methane emissions from individual production areas, based on extensive measurements of methane leakage reported in the literature and recent gas production rates. The model represents all natural gas production in the contiguous U.S., including offshore. The model allocates a portion of the methane leakage to natural gas that is consumed by end users, based on energy content of consumer-grade natural gas produced; the remaining methane leakage is allocated to natural gas liquids and oil. For each gas-producing state, the model sums methane emissions for methane leaked from oil and gas production operations that is attributable to gas consumed by end users. Then the model calculates the methane leakage intensity for dry gas produced (quantity of methane leaked per unit of dry gas), as well as methane leakage intensity for natural gas liquids and oil produced.

Second, the model uses EIA data on flows of gas supplies across state lines to estimate the origins of the gas consumed in each state. Based on the origins of the gas in various producing states (or other nations), the model calculates an average methane leakage intensity for the gas consumed in each state.

Third, for particular cities, the model calculates the approximate distances traveled by the gas through transmission pipelines, from the production areas to cities where gas is consumed, from each of the producing states. GIM calculates an average distance gas travels to reach each city, and estimates methane leakage from the transmission system on that basis.

Fourth, based on data for the gas utilities serving particular cities, detailing the utilities' distribution networks and customer base, the model estimates methane leakage from pipelines within cities and from customer gas meters. For cities that have had comprehensive measurements of methane leakage, or credible reports of methane leakage from gas utilities, the model adds additional methane leakage based on these measurements or reports. For gas utilities' systems, methane leakage is allocated separately to residential and commercial customers, and to industrial and electric power customers.

Fifth, the model estimates methane leakage from buildings, known as "behind the meter" or "beyond the meter" leakage. This leakage has been found to occur from gas pipes within buildings and from gas-burning appliances (e.g., furnaces, water heaters, stoves).

The model also calculates additional citywide leakage may be occurring, for those cities that have had measurements of methane leakage and estimations of the fraction that originates from natural gas. This additional leakage is above what is estimated for citywide leakage in the model.

Finally, the model estimates changes in greenhouse gas emissions when switching residential/commercial heating from gas heaters to electric heaters.

To see the Gas Index results, visit the website: https://thegasindex.org

3. Leakage from oil and gas production areas

Methane leakage from oil and gas production areas (also known as upstream oil and gas) is one of the major sources of methane leakage throughout the fossil gas supply chain. In GIM, leakage from production areas is calculated based on data in the scientific literature for estimated leakage rates for individual oil and gas production areas, based on measurements of methane emissions.

Most of these methane measurements are top-down, meaning they measure emissions from large areas using sensors flights, satellites, or towers. All methane leakage in an area influences these measurements, whether the methane is from oil and gas activities, or other sources such as livestock, coal mines, and landfills. Among oil and gas activities, methane leakage can occur from oil and gas extraction, as well as storage, gathering, and processing. To estimate the methane solely from oil and gas operations, most studies subtract estimated emissions from other sources (such as livestock) to estimate the leakage solely from oil and gas activities.

GIM also estimates the methane leakage attributable to production of natural gas consumed by end users, as opposed to the methane leakage attributable to production of crude oil and natural gas liquids (see section 5, "Attributing leakage to consumer-grade natural gas").

However, most studies of methane leakage from oil and gas production areas compare the total methane leaked to the gross gas extracted. Therefore, the following description in this section follows that practice. (For GIM's attribution of methane leakage specifically to gas consumed, see Section 5.)

3.1. Leakage rates by U.S. production area

Since 2012, most oil and gas producing areas have now had their methane leakage measured by at least one top-down survey, including flights around the areas and satellite imaging of specific areas. In 2018, production areas with methane leakage rate estimates, as shown in Table 3-1, were responsible for 89% of gross gas extraction in the contiguous U.S., and approximately 90% of crude oil production in the contiguous U.S.[1]

GIM uses as inputs the leakage rates shown in Table 3-1, which reports the years in which the measurements were taken. All leakage rates are calculated on a volume basis, for methane leaked from oil and gas production areas, compared with the methane content in gross gas produced (also known as "raw gas").

Throughout Section 3, the values shown for leakage rates are prior to any allocation between different products (consumer-grade natural gas, NGLs, and oil).

See Table 3-2 for the reported methane content of gas in each production area. Appendix A lists the studies of methane leakage measurements used as inputs to GIM, as well as rationales for use of those studies. If the methane leakage studies did not explicitly state a leakage rate, Appendix A describes the methods for calculating a leakage rate. If more than one study was used for estimating the leakage rate for a given production area, Appendix A provides details on the calculations.

[1] The calculation for crude oil production is approximate because we are not aware of readily available data for oil production from the Gulf of Mexico offshore within state waters. For gas production, EIA publishes data on the Gulf of Mexico for federal and state waters separately, and in 2018, federal waters were responsible for 92% of gas production. For the oil production estimate here, we assume that similarly total Gulf of Mexico offshore oil production is 92% from federal waters. Excluding oil production from Gulf of Mexico state waters, the oil produced from areas with methane leakage measurements accounts for 89% of contiguous U.S. oil production.

Table 3-1. Measured leakage rates for gas production areas in the contiguous U.S. used as inputs for GIM. Gross production volumes, and percent of contiguous U.S. gas volume, are based on gross withdrawals ("raw gas") in 2018, reported by EIA as of October 30, 2020. Methane leakage rates are calculated on a volume basis, for methane leaked from oil and gas production areas, compared with the methane content of gross gas produced. (However, final results from GIM for life cycle emissions allocate methane leakage separately by product, between dry gas, NGLs, and oil.) Methane leakage rates shown are rounded to 2 significant digits. For sources of data for methane leakage rates for each production area, with associated uncertainty ranges, see Table 3-2, and also detailed descriptions in Appendix A.

Production area	Gas production (Bcf/year)	% of contiguous U.S. gas production	Methane leakage rate†
Appalachia region (outside northeast PA)	7,086	20.8%	0.88%
Appalachia region (northeast PA)	3,368	9.9%	0.33%
Permian region	4,213	12.4%	3.7%
Haynesville region	3,338	9.8%	1.3%
Anadarko region	2,632	7.7%	5.7%
Eagle Ford region – east	1,385	4.1%	3.2%
Eagle Ford region – west	735	2.1%	2.0%
Greater Green River region ‡	1,323	3.9%	1.3%
San Juan region	1,293	3.8%	3.4%
Offshore Gulf of Mexico (state & federal waters)	1,079	3.2%	2.9%
Barnett region	1,203	3.5%	1.5%
Denver-Julesburg region	923	2.7%	3.1%
Bakken region	871	2.6%	5.9%
Fayetteville region	519	1.5%	1.3%
Uintah region	230	0.7%	9.7%
San Joaquin Valley	142	0.4%	10%
Total	30,346	89.1%	
Weighted average			2.3%

† The methane leakage rate is calculated as the volume of methane leaked divided by the volume of methane contained in gross natural gas produced.
‡ Based on well-site measurements used in a bottom-up estimate of the methane leakage rate. All other measurements in Table 3-1 from top-down studies, using flights, satellites, and/or towers.

Table 3-2. Methane leakage studies used as inputs to GIM. Leakage rate is a percentage volume of gas that methane in gross gas produced that leaks. If the study stated a methane leakage rate ± an uncertainty, that is converted here to a range for ease of comparison across studies. If the type of uncertainty range (e.g., 1σ) was stated in the study, that is reported below.

Production area	Methane measurement study	Measurement year(s)	Methane leakage rate (%) with uncertainty	% methane in gross gas
Appalachia region (outside northeast PA)	Ren 2019	2015–2016	1.1% (0.78–1.5%)	87.8%
	Barkley 2019	2015–2016	0.66%†	88%†
	GIM average		**0.88%**	**88%**
Appalachia region (northeast PA)	Barkley 2017	2015–2016	0.36%	95%
	Peischl 2015	2013	0.30% (0.18–0.41%)†	96%
	GIM average		**0.33%**	**96%**
Permian region	Zhang 2020	2018–2019	3.7%	80%
Haynesville region	Peischl 2015	2013	1.6% (1.0–2.1%)	90%
	Peischl 2018	2015	1.0% (1σ 0.5–1.5%)	90%
	GIM average		**1.3%**	**90%**
Anadarko region	Schneising 2020	2018–2019	5.6% (4.0–7.1%)	93%†
Eagle Ford region – east	Peischl 2018	2015	3.2% (1σ 2.1–4.3%)	68%
Eagle Ford region – west	Peischl 2018	2015	2.0% (1σ 1.4–2.6%)	77%
Greater Green River region	Omara 2018	2014–2015	1.3% (no range)†	78%
San Juan region	Smith 2017	2015	3.4% (2.8–4.0%)†	83%†
Barnett region	Karion 2015	2013	1.5% (1.2%–1.8%)	87%
	Peischl 2018	2015	1.5% (1σ 0.5–2.5%)	89%
	GIM average		**1.5%**	**88%**
Offshore Gulf of Mexico (state & federal waters)	Negron 2020	2018	2.9% (2.2–3.8%)	85%
Denver-Julesburg region	Pétron 2014	2012	4.1% (2.6%–5.6%)	73%†
	Peischl 2018	2015	2.1% (1.2–3.0%)	77%
	GIM average		**3.1%**	**75%**
Bakken region	Peischl 2016	2014	6.3% (4.2–8.4%)	47%
	Peischl 2018	2015	5.4% (3.4–7.4%)	47%
	GIM average		**5.9%**	**47%**
Fayetteville	Schwietzke 2017	2015	1.3%†	94%†
Uintah region	Karion 2013	2012	8.9% (6.2–12%)	89%
	Foster 2019	2015–2016	10.4†	89%†
	GIM average		**9.7%**	**89%**
San Joaquin Valley	Cui 2019b	2014–2016	10%†	91%†

† See Appendix A for explanation of leakage rate and/or % of methane by volume in gross gas listed here.

Some production areas have not had comprehensive methane leakage measurements taken in the past several years. As more data becomes available from further studies, including satellite measurements, these can be incorporated into GIM to update the results. These updated results may show different leakage rates than reported in Table 3-1. In particular, if there are efforts to reduce methane leakage in particular production areas—for example, due to regulations enacted in Colorado and New Mexico—this could lower the leakage rates that are inputs to GIM.

For the remaining 10% of production for the U.S. production that has not been measured, the model assumes a default leakage rate equal to the weighted average of the production areas (2.3%).

We attempted to find all top-down methane measurement studies of U.S. gas producing areas to use as inputs to GIM. However, most measurements were taken in years prior to the year of analysis for the model (2018). GIM assumes that the leakage rates based on past measurements apply to production in the year of analysis. The only production area with repeated measurements of methane leakage by similar methods, and finding a substantially different leakage rate, was the Bakken (Schneising 2014, Schneising 2020). See Appendix A for more details.

As shown in Table 3-1, methane leakage rates are calculated as a percentage of the methane content of gross gas extracted, since that is the standard within the studies that have measured leakage from production areas. However, GIM life cycle emissions estimates do not allocate all methane leakage that occurs in oil and gas production areas to natural gas that is ultimately consumed by end users. Instead, the model allocates methane leakage to dry gas (consumer-grade gas), to natural gas liquids, and to oil, on the basis of the estimated energy content of gross extraction of product. Description of the process for allocating methane leakage between gas and other products is in Section 5.

3.2. Leakage volume by U.S. production area

For each production area, GIM calculates the volume of methane leaked as:

$$CH_4\ leakage\ rate\ (vol.) = gross\ gas\ production\ (vol.) \times leakage\ rate \times\ CH_4\ fraction$$

For each production area that has had methane leakage measured by studies in the scientific literature, the value used for the leakage rate is as shown in Table 3-1, and the value for the methane fraction is as shown in Table 3-2.

For the 10% of contiguous U.S. gas production from areas that have not been measured by methane leakage studies, the model applies a default leakage rate equal to the average rate calculated for the 89% of gas production that is covered by measurements (2.3%). For these areas, GIM also applies a default value for the fraction of methane in raw gas, equal to the weighted average for the production areas that have been measured (85%).

- For each production area, the methane fraction of raw gas (by volume) is from the scientific literature, as shown in Table 3-2. If there is more than one methane leakage study for a given production area, GIM uses the average of the methane fractions across the studies, as shown in Table 3-2. Values were reported in the studies that measured methane emissions for all basins except for Anadarko, San Juan, and San Joaquin Valley; for those basins, values were derived from other studies, and converted from mass fractions if necessary. Whenever the studies that measured methane leakage stated the methane fraction assumed in calculating the leakage rate, GIM uses the same methane fraction reported.

3.3. Comparison with other estimates of U.S. production area leakage

3.3.1. Comparison with EPA's Greenhouse Gas Inventory

For oil and gas production areas, the U.S. average leakage rate calculated in GIM for 2018 is 2.3%, which is at least 2.5 times the 2018 leakage rate in EPA's Greenhouse Gas Inventory (GHGI) for oil and gas production areas (including gathering and processing activities).[2]

The higher leakage rate in the GIM is explained by the use of extensive measurements of methane emissions, whereas the GHGI is based on bottom-up inventories of emissions. Such bottom-up inventories have been found to systematically underestimate methane emissions, in particular when there are a small number of super-emitters that are responsible for a large share of the overall emissions; such super-emitters are often not well characterized in measurement surveys used as the basis for bottom-up inventories (Brandt 2014, Brandt 2016, Zavala-Araiza 2015b, Zavala-Araiza 2017).

We note that EPA continually revises their methodology for the GHGI, often making retroactive adjustments to values in earlier years. For example, the 2020 edition reduced the estimated values, retroactively, for gathering and boosting by ~30% compared with the 2017 edition. Thus, the leakage rates based on EPA data released in 2020 are lower than in EPA data released in 2017 and used in Alvarez 2018 (see below).

3.3.2. Comparison with Alvarez 2018

The GIM average leakage rate for production areas is 2.3%, which is ~20% higher than the 1.9% leakage rate in Alvarez 2018 for production areas, including production, gathering, and processing activities.[3] However, this difference may be due in part to differing assumptions, such as for the methane content of natural gas; when calculating the leakage rate in terms of g CH4/Mcf of gas, as shown in the main report, there is little difference between the results of the two analyses. The year of analysis in Alvarez 2018 is 2015, whereas the year of analysis in GIM in 2018.

Table 3-3 shows leakage rates for various oil and gas production areas Alvarez 2018, as compared with the values in GIM.

For production area leakage, Alvarez 2018 drew on top-down methane leakage measurements, as well as bottom-up measurements at well sites. Since Alvarez 2018 was published, additional top-down measurements have become available for regions that were not covered in that study, including the Permian region, Anadarko region, and offshore Gulf of Mexico. All of these newly covered areas had estimated leakage rates higher than the 1.9% average leakage rate for production areas in Alvarez 2018.

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[2] EPA's GHGI reported methane emissions in 2018 for production areas (including exploration, production, and gas processing categories), specifically for natural gas systems, was 3,770 kilotons. For petroleum systems there were an additional 1,410 kilotons, for a total of 5,179 kilotons from oil and gas (EPA 2020a). EIA reported dry gas production in 2018 to be 30,588,702 MMcf (EIA 2020f). Assuming gross gas is 95% methane by volume, and the density of methane under standard conditions of 19.3 tons/MMcf, then the dry gas contained 560,844 kilotons of methane. Adding the methane that leaked in production areas, the methane in gross gas extracted was 566,023 kilotons. The leakage rate based on EPA estimates is therefore 5,179 / 566,023 = 0.9% (rounded). If counting only the methane leakage that EPA allocates to natural gas systems, the EPA leakage rate would be 3,770 / 566,023 = 0.7% (rounded).

[3] Alvarez 2018 reported that 13 Tg methane leakage was equivalent to a leakage rate of 2.3%, relative to total gas extracted. Alvarez 2018 Table 1 reports Tg methane leakage of 10.9 Tg from production, gathering, and processing. Multiplying 10.9 Tg by the ratio 2.3%/13 Tg yields a leakage rate from production areas of 1.9%.

Alvarez 2018 reported that the basins with leakage measurements accounted for ~33% of U.S. gas production (or ~37% of contiguous U.S. gas production), whereas GIM draws on measurements for basins that account for 89% of gas production in the contiguous U.S. Due to drawing on more extensive measurements, including from production areas that leak at higher rates, GIM has a higher leakage rate on average.

We also note that the 2.3% leakage rate calculated in GIM for production area leakage is equal to the leakage rate estimated in Alvarez 2018 for the whole gas system, including also leakage from transmission and storage, as well as distribution leakage.

However, an important difference between these studies is that GIM allocates methane leakage from oil and gas production areas between the different products (dry gas, NGLs, crude oil), whereas Alvarez 2018 allocates all methane leakage from the whole system to the gas consumed by end users.[4]

In contrast, in GIM, methane leakage from oil and gas production areas is allocated—as a weighted average across the contiguous U.S.—53% to dry gas, and the remaining 47% to NGLs and crude oil. See Section 5 for details on GIM's allocation of production area methane leakage across products.

Another difference between these studies is that Alvarez 2018 used EPA Greenhouse Gas Inventory (GHGI) estimates for leakage from distribution, whereas GIM makes its own estimates for parts of the distribution system where there are new studies with extensive measurements to draw on, in particular:

- Distribution mains
- Commercial customer gas meters
- Industrial and electric customer gas meters
- Behind-the-meter leakage

These studies have all found substantially higher leakage for each of these components than in EPA's GHGI. Where there are not extensive new studies to draw upon, GIM uses EPA GHGI estimates; this is the case for leakage from distribution service lines and residential customer meters. See Sections 8-12 for details on GIM's estimates of methane leakage from the distribution system.

3.3.3.Comparison with Omara 2018

Omara 2018 drew on methane leakage measurements at well sites to create bottom-up estimates for methane leakage at well sites. Omara 2018 estimated an average leakage rate of 1.5% for the contiguous U.S. onshore, when using a nonparametric model that incorporated super-emitters. These measurements covered ~60% of production from the contiguous U.S. onshore, or ~50% of production from the contiguous U.S., including offshore (Omara 2018, authors' calculations).

[4] In Alvarez 2018, one of the headline conclusions was: "Methane emissions [estimated in this study] per unit of natural gas consumed, produce radiative forcing over a 20-year time horizon comparable to the CO_2 from natural gas combustion." The study's supplemental information explains: "Our estimate of supply chain emissions, 13 Tg CH4/y, represents 2.9% of total methane delivered (25 tcf/y NG delivered, assuming an average CH4 content in NG of 95% by volume). At a loss rate of 2.9% of gas delivered, CH4 emissions across the supply chain, per unit of gas consumed, result in 92% of the radiative forcing caused by the CO2 from combustion of natural gas, over a 20-year time horizon (31% over 100 years)." Therefore, we conclude that Alvarez 2018 allocated all methane leakage from oil and gas production areas to gas produced, and none to oil produced.

The leakage rates from Omara 2018 are shown in Table 3-3, compared with values used in GIM and in Alvarez 2018. For basins where measurements were not available, Omara 2018 inferred methane emissions; those entries are marked with asterisks. The inferred values shown are results from the study's nonparametric model, which incorporates emissions from super-emitters.

Table 3-3. Methane leakage rates for oil and gas production areas in Alvarez 2018 and Omara 2018, compared with values used in the Gas Index Model (GIM). Leakage rates are calculated on a volume basis, for methane leaked from oil and gas production areas, compared with the methane content of gross gas (raw gas) produced. Omara 2018 covered all onshore production in the contiguous U.S., but for some production areas delineated in GIM, Omara 2018 did not report a corresponding value; those cells are labeled n/a. For production areas that were not included in a given study, the table cells are empty. Alvarez 2018 and GIM input values are for leakage from production areas, including emissions from well sites, gathering, and processing; Omara 2018 values are for leakage measured at well sites, and thus, all else being equal, are expected to be lower.

Production area	Alvarez 2018 (top-down studies)	Omara 2018 (bottom-up studies)	Gas Index Model (GIM) inputs
Appalachia		0.9%	0.7%
Appalachia: northeast PA	0.4%	n/a†	0.4%
Appalachia: southwest PA		n/a†	0.9%
Appalachia: West Virginia		n/a†	0.9%
Appalachia: Ohio		n/a†	0.9%
Permian		2.5%*	3.7%
Haynesville / TX-LA-MS-Salt	1.3%	1.2%*	1.3%
Anadarko		1.7%*	5.7%
Eagle Ford / Western Gulf		1.1%	2.5%
Greater Green River		0.9%	1.3%
San Juan	3.0%	4.5%*	3.0%
Barnett (Fort Worth)	1.4%	1.4%	1.5%
Offshore Gulf of Mexico			2.9%
Denver-Julesburg (aka Weld)	3.1%	2.8%	3.1%
Uintah	6.6%‡	1.5%	9.7%
Bakken (Willison)	3.7%‡	2.2%*	5.9%
Fayetteville shale (within Arkoma basin)	1.4%	1.1%	1.3%
Eastern Arkoma (western part of Arkansas)	9.1%	n/a	
San Joaquin Valley		4.8%*	10%
Ardmore		1.8%*	
Powder River		1.7%*	
Michigan		2.8%*	
Cherokee Platform		4.8%*	
Other basins		4.4%*	
Weighted average leakage rate	1.9%	1.5%	2.3%
% of contiguous U.S. gas production covered by leakage measurements	~37%	~50%	89%

* Omara 2018 value not based on measurements; was estimate based on well production rates.
† Included within the Appalachia production area; Omara 2018 did not report leakage rates for subregions.
‡ Alvarez 2018 Table S2 stated a leakage rate that is lower than what is stated in the study cited in that table. See Appendix A for details.

We note that the values in Omara 2018 were derived from on-the-ground measurements at well pads, and thus do not capture additional methane emissions that occur within the basins, from activities categorized as gathering and processing; Alvarez 2018 estimated that 30% of production area emissions are from gathering and processing. Thus, there are significant additional emissions that are not included in Omara 2018.

The only production area in Omara 2018 that had an emissions estimate based on methane measurements within that area, and that is not yet covered by top-down measurements we identified, is the Greater Green River Basin. Omara 2018 estimated a leakage rate for this production area of 0.88%, based on well-site measurements. GIM draws on this well-site leakage rate, adjusting it to approximate an emissions rate for the whole production area, including gathering and processing leakage. See Appendix A for details on the Greater Green River region methane leakage calculations.

In Omara 2018, there are 10 named production areas, as well as the category "other basins," that did not have measurements of on-site methane emissions. Omara 2018 estimated leakage rates for these areas based on well production rates, and a correlation in other basins between well production rates and methane leakage rates. The study found that, in general, wells with lower production rates leak a higher percentage of the gas produced. For production areas with inferred leakage rates, not based on measurements, the leakage rates in Table 3-3 are marked with asterisks. The largest of those basins (Permian, Anadarko, and Haynesville) have been covered by recent top-down measurements, and those results are incorporated in GIM, providing much more extensive coverage of U.S. gas production by leakage measurements than available at the time of Omara 2018.

The basins/regions that Omara 2018 estimated leakage rates for, and that are still not covered by methane measurements to date, are: Ardmore, Powder River, Michigan, Cherokee Platform, and "other basins." In 2015 (the year of analysis used in Omara 2018), these areas produced 1,640 Bcf, 6% of contiguous U.S. gas production. For these areas, the weighted average leakage rate, using the leakage rates and production rates reported in Omara 2018 Table S9, is 4.0%. GIM estimates methane leakage from these areas by applying the U.S. average leakage rate (2.3%) calculated from the 89% of the contiguous U.S. covered by top-down measurements. If the Omara 2018 estimates for leakage rates for these basins were used as inputs to GIM, it would slightly raise the contiguous U.S. average leakage rate from 2.3% to 2.4%.

Alternatively, the leakage rates in Omara 2018 for the production areas listed in the previous paragraph could be increased to reflect additional emissions from gathering and processing (as was done for the Greater Green River basin), to represent additional emissions no captured in the well-site measurements used in Omara 2018. In this case, the leakage rate for this set of production areas would increase from 4.0% to 5.7%. Incorporating these increased emissions rates into GIM would raise the contiguous U.S. average leakage rate from 2.3% to 2.6%.

GIM does not include the Omara 2018 estimated leakage rates for these production areas in order maintain consistency in relying on measured, rather than inferred, leakage rates. Also, the result of excluding these Omara 2018 estimates is to make the overall leakage rate lower.

4. Attributing leakage from production areas to states

From the leakage quantities for each production area, described in section 3, GIM estimates the leakage that occurs within each state. For production areas that cross state boundaries, GIM uses data from state agencies to calculate the gross gas production from each region, within in each state (e.g., Permian gross gas production is 79% from Texas and 21% from New Mexico). See below for a detailed description of how state agencies' data is accessed.

This production data is then used to separate the methane leaked on the basis of the share of production in each state. GIM assumes that the leakage rate measured for a production area (e.g., 3.7% for the Permian) applies to all portions of the production area (e.g., the portions of the Permian in Texas and in New Mexico).

If more granular measurements for methane leakage are published in the future, then it may be possible to distinguish leakage rates between portions of production area (e.g., the portion of the Permian region in New Mexico versus the portion in Texas).

4.1. State agencies' data on production

GIM's production volumes of gross gas and oil for each production area (e.g., Appalachian region) are based on data reported by state agencies wherever possible. Appendix B lists the state websites from which we obtained detailed oil and gas production data, at the county or well level. States differ in the level of detail in data that is readily accessible, without requiring special requests. Data was available at the county level or below for all major significant producing states that also had been covered by methane leakage measurements, with the exception of Oklahoma.

The Oklahoma Geological Survey notes: "Public access to [oil and gas production] data is provided by the Oklahoma Corporation Commission, although these data are not complete. The most complete sources of data are available from pay-for-use providers such as Drillinginfo and IHS Energy" (Oklahoma Geological Survey 2020). Therefore, for dividing production from the Anadarko region, GIM takes production data from the EIA Drilling Productivity Report (EIA 2020a) for total Anadarko production and subtracts county-level production for the portion of the Anadarko in Texas. The remaining Anadarko production is allocated to Oklahoma.

For production areas covered by EIA's Drilling Productivity Report (EIA 2020a), that report defines particular production areas based on county-level boundaries, with all oil and gas production from the specified counties counting toward the production from each area. For the Appalachian, Anadarko, Bakken, Eagle Ford, Haynesville, and Permian regions, GIM uses the same counties to delineate production areas, and calculates the gross gas production in the region from state agencies' data, including the portion of production in each region that is within each state. GIM does not use the Niobrara region defined in the Drilling Productivity Report, because it encompasses three distinct oil and gas basins; instead, GIM uses measurements of methane leakage for two of the sub-regions, the Denver-Julesburg basin and the Greater Green River basin, and uses the model's default methane leakage rate for remaining production in the Niobrara region.

5. Allocating leakage to consumer-grade natural gas

In GIM, methane leakage that occurs in production areas is allocated separately to production of dry gas (consumer-grade gas) produced, of natural gas liquids (NGLs), and of crude oil, on an energy basis.

5.1. Reasons for allocating methane leakage between products

Separating between products is in keeping with other estimates of life cycle emissions from production of fossil fuels, such as a study by the National Energy Technology Laboratory of U.S. natural gas (Littlefield 2019).

There are multiple rationales for allocating methane leakage separately to dry gas, NGLs, and oil:

- Dry gas is not the only product from the areas in which methane leakage occurs; also, in some production areas, such as the Permian basin, oil is likely the driving factor behind most drilling in recent years, with gas as a by-product.
- There are oil wells that are not connected to gas gathering lines, and so flare or vent the gas that is produced; furthermore, surveys in the Permian have found many of these flares are malfunctioning or unlit, allowing far more methane to escape than if they were functioning as intended (EDF 2020a). If the quantities of such leakage from oil wells not connected to gas gathering lines could be estimated separately from other leakage from production areas, this leakage would be best allocated to oil as a product, rather than to dry gas or NGLs.
- Significant leakage occurs in oil and gas production areas from liquids storage tanks, which off-gas methane (Lyon 2016, Lavoie 2017).
- Among the U.S. production areas that are the most active for modern unconventional production (with long horizontal wells and high-volume hydraulic fracturing), oil-rich producing areas have shown higher leakage rates than areas that produce mostly gas. For example, the oil-rich Permian and Anadarko regions have relatively high leakage rates, compared with gas-dominated production areas (Appalachian, Haynesville, Fayetteville, Barnett).
- Well-site methane measurements in Alberta, Canada, also found that oil-producing sites "tend to have higher emissions than sites without oil production" (Zavala-Araiza 2018).

5.2. Comparing methods of allocating methane leakage

GIM uses an allocation approach, in which methane leakage is divided on an energy basis between the products from oil and gas producing areas. Below is a description of the process for energy share of consumer-grade gas, out of the total energy content of oil and gas.

Top-down estimates of methane leakage from oil and gas production areas draw on measurements (e.g., by flights) that capture methane from all sources in the area, including oil and gas operations, livestock, coal mines, and landfills. Top-down estimates used as inputs to GIM normally exclude methane sources other than from oil and gas, drawing on other bottom-up inventories and/or additional measurements, such as ethane emissions. (For more details on individual top-down studies used as inputs to GIM, see Appendix A.)

Top-down studies do not distinguish between methane leakage from different elements of oil and gas operations, e.g., well-site activities, gas gathering systems, and gas processing facilities. Therefore, all leakage from these activities is treated together in GIM.

An alternative method of allocating methane leakage between products from oil and gas producing areas would be on a mass basis, rather than an energy basis. A rationale for using a mass basis is that not all of

the products are used as fuels, and some are used as chemical feedstocks and for making plastics (DOE 2017).

Another alternative method of allocating methane leakage between products is on an economic value basis. Zavala-Araiza 2015c compared methane allocation between products on an energy basis and mass basis, finding little difference between the results of the two methods.

5.3. Detailed description of allocation on an energy basis

Calculation of energy content of dry gas, NGLs, and oil:

- **Dry gas:** EIA publishes data on dry gas production volumes by state (EIA 2020f). GIM uses this data and multiplies it by EIA's standard energy density for dry (consumer-grade) gas, 1,037 Btu per cubic foot (EIA 2020c), to calculate the energy content of dry gas produced in each state.[5]
- **NGLs:** EIA publishes data on NGL production volumes (barrels) by state, in which all NGLs are grouped together (EIA 2020f). However, states may vary in the mix of NGLs they produce, and various NGLs have different energy densities. EIA also publishes data on NGL production by type—ethane, propane, normal butane, isobutane, and natural gasoline (pentanes plus)—for each Petroleum Administration for Defense District (PADD), of which there are five (EIA 2020d). EIA also states the energy density for each type of NGL.[6] For each PADD, GIM calculates an average energy density of NGLs based on the production volume and energy density of each type of NGL. GIM then calculates the energy content of NGLs produced in each state by multiplying the NGL production volumes in each state by the energy density of NGLs produced for the PADD that state is within.
- **Oil:** EIA makes available data on crude oil production in each state. GIM multiplies this oil production by the energy density of oil, 5.698 MMbtu per barrel (EIA 2020c), to yield the energy content of oil produced in each state.

The values for the share of energy from oil and gas production that comes from each product (dry gas, NGLs, and crude oil) are shown in Table 5-3 for major producing states (and federal waters in the Gulf of Mexico). Values are sorted in descending order from the state that produces the highest quantity of energy from oil and gas (Texas).

[5] EIA does publish heat content of consumer-grade gas by state, in the Natural Gas Monthly, Table 25, "Heating value of natural gas consumed, by state" (EIA 2020n). However, in 2020, the values varied little by state, with the lowest value 2% below the mean, and the highest value 5% above the mean.

[6] EIA stated the energy densities of NGLs (in million Btu per barrel of liquid): ethane, 3.082; propane, 3.836; normal butane, 4.326; isobutane, 3.974; and pentane plus (also known as natural gasoline), 4.620 (EIA 2020e).

Table 5-3. Percentage of energy in total oil and gas production that derives from each product (dry gas, NGLs, or crude oil). Only major producing states are shown. Values are calculated from EIA data on production of each product at the state level; data sources are described above. Values are for all oil and gas production, without distinguishing wells that produce only oil from those that produce gas as well as other products (NGLs and/or oil).

State/Nation	Dry gas	NGLs	Crude oil
Contiguous U.S.	53%	10%	37%
Texas	38%	13%	48%
Pennsylvania	96%	3%	1%
GOM (federal)	19%	5%	76%
Oklahoma	60%	14%	25%
North Dakota	16%	10%	73%
Louisiana	89%	2%	8%
New Mexico	45%	10%	45%
Colorado	56%	12%	31%
Ohio	89%	6%	5%
Wyoming	71%	8%	22%
West Virginia	78%	19%	3%

Of the methane leakage that occurs in oil and gas production areas, on average across the contiguous U.S., GIM allocates 53% of that leakage to dry gas and the remaining 47% to NGLs and crude oil.

Table 5-3 shows that some states produce mostly oil, such as North Dakota, and some mostly gas, such as Pennsylvania. For Pennsylvania, 96% of production-area leakage is allocated to dry gas, whereas in North Dakota (where most oil and gas production comes from the Bakken region), only 16% of production-area leakage is allocated to dry gas.

Table 5-4 shows GIM results for methane leakage allocated to dry gas produced, for major producing states. The methane leakage is shown as a rate of methane leaked per unit of dry gas produced.

Table 5-4. Methane leakage for major producing states, for leakage from oil and gas production areas that is allocated to dry gas production. Values for leakage rates are rounded to 2 significant digits for display.

State	Dry gas production (Bcf)	Leakage rate (g CH_4/Mcf dry gas)
Texas	7,029	210
Pennsylvania	6,177	100
Louisiana	2,801	230
Oklahoma	2,625	520
Ohio	2,341	140
Colorado	1,704	290
West Virginia	1,613	130
Wyoming	1,573	180
New Mexico	1,368	280
GOM (federal)	889	100
Arkansas	590	240
North Dakota	566	130
Utah	284	790
California	193	240

6. Tracing cities' gas consumption to production sources

To allocate the leakage that occurs in producing areas to gas consumption in particular cities, each city's gas supplies must be traced back to various gas-producing areas.

The model simulates gas production in each state and gas trade between states, and thus can allocate gas consumed in each state to the gas produced in the same state or other states. The model covers consumption in the contiguous U.S. (including Washington, D.C.). The model also includes pipeline gas trade with Canada and Mexico, and overseas imports and exports of liquefied natural gas (LNG).

GIM assumes that all cities in a given state consume the same mix of gas from various producing states or nations. This assumption may not reflect the actual supplies in each part of the state, e.g., in southern California (served mainly by imports via Arizona) versus northern California (served mainly by imports via Nevada and Oregon). A preliminary analysis suggested the difference between the leakage for northern and southern California is small, when considering leakage from production areas as well as transmission leakage (described in the section "Transmission leakage"). Therefore, GIM does not distinguish between gas supplies in different parts of a state.

In GIM, gas consumption for each state from EIA is allocated to producing states based on EIA data for gross flows (imports and exports) between states or other jurisdictions (EIA 2020h). GIM calculates each state's gross gas supply, made up of the state's own gas production and its gross imports of gas. Gross imports are traced back to their ultimate origins in producing states through an iterative process that steps through each state and traces where its gross supply originated, whether from its own production, or from gross imports from neighboring states or other countries.

To give a hypothetical example, suppose state A's gross supply is 30% production in-state and 70% imports from state B. State B has no in-state production, and imports 40% of its gas from state C and 60% from state D. States C and D produce gas, and don't import any gas. Thus, the gas supply for state A would be allocated ultimately to:

- state A production: 30%
- state B production: 0%
- state C production: 70% × 40% = 28%
- state D production: 70% × 60% = 42%

Gas flows in the U.S. are considerably more complicated than in the hypothetical example above, and the iterative process of attributing consumption back to production areas contains many loops. (In graph theory, networks with such loops are referred to as cyclic graphs.)

To approximately solve the attribution to producing states, the GIM runs its iterative process until at least 99% of each state's consumption is allocated to producing states, or until it reaches 5,000 iterations in attributing a given set of imports (e.g., imports into state A from state B), whichever is reached first. If a portion of the imports remains unallocated after these iterations, then the attributions to the producing states are scaled up to equal the known gross imports.

Before scaling up to account for unallocated portions, the model allocated on average 94% of the imports back to producing states; the lowest share of imports it allocated was 75% (for imports via Michigan).

6.1. Validation of tracing consumption to production areas

The gas consumed, as traced back to each producing state, was summed for each producing state, and then compared against EIA data for production for each state. EIA reports different classes of natural gas

production, including gross extraction, marketed production, and dry production (EIA 2020f). EIA's glossary describes dry gas as "consumer-grade natural gas."[7]

Gas volumes that cross state boundaries are reported through form EIA-176. Prior to entering long-distance transmission pipelines, this gas has gone through any processing required to remove most of the natural gas liquids, but it often does contain some remaining natural gas liquids, mainly ethane.

Thus, for internal consistency between production data and consumption data, the Gas Index Model uses dry gas production values for attribution of consumption back to production areas, and for validation of model results.

However, there appear to be discrepancies in EIA's data, which is gathered from a variety of companies throughout the natural gas system, including well operators that report production, pipeline operators that report volumes entering transmission pipelines, and storage operators that report volumes entering or exiting their facilities. Ideally, if there were no leakage and perfect data reporting, for each state the following would be true:

$$dry\ gas\ production - net\ exports + net\ storage\ withdrawals - consumption\ = 0$$

However, there are discrepancies in EIA data such that the right-hand side of the above equation is not zero, even for states that produce no gas or negligible quantities of gas, removing one potential contributor to discrepancies. Also, the discrepancies are positive for some states and negative for others, even among major net exporting states (Table 6-1). Thus, the discrepancies do not seem to be solely due to differences in definitions of gas grades, e.g., between dry gas produced and consumer-grade gas that is transported across state lines. Some of the values should be impossible, for example, West Virginia shows larger net exports than the sum of dry gas production and storage net withdrawals, without even accounting for gas consumption.

Table 6-1. Discrepancies in EIA natural gas data for major gas producing states. All data for 2018, as released by EIA on June 30, 2020.

State	Dry gas production (MMcf)	Net exports (MMcf)	Storage net withdrawals (MMcf)	Consumption (MMcf)	Supply – consumption discrepancy (MMcf)	Discrepancy (% of dry gas production)
Texas	6,835,349	2,739,076	59,567	4,432,552	-276,712	-4.0%
Louisiana	2,779,623	1,097,231	58,314	1,733,676	7,030	0.3%
Oklahoma	2,695,569	1,733,495	11,813	808,689	165,198	6.1%
Ohio	2,346,583	1,259,636	4,840	1,139,358	-47,571	-2.0%
Colorado	1,688,040	1,093,410	5,422	487,130	112,922	6.7%
West Virginia	1,640,160	1,678,375	17,127	204,297	-225,385	-13.7%
Wyoming	1,575,261	1,250,558	2,911	164,341	163,273	10.4%
Arkansas	589,689	223,487	-654	360,814	4,734	0.8%
North Dakota	565,551	435,348	n/a	126,719	3,484	0.6%
Utah	285,248	14,704	7,760	243,772	34,532	12.1%

[7] https://www.eia.gov/tools/glossary/

The discrepancies may be in part due to methane leakage, but we argue that methane leakage is likely a small component of the discrepancies because:

- The data has been revised substantially over time, e.g., from the data set released in May 2020 to the data set released in September 2020, West Virginia's net exports were revised down, from 1,678,375 to 1,546,327 MMcf, a decrease of 7.9%, whereas values for some other states (such as Oklahoma and Colorado) were unchanged. Similarly, production data has changed, with Texas's dry gas production for 2018 increasing from 6,835,349 MMcf to 7,029,257 MMcf (an increase of 2.8%). Thus, any relatively recent data appears to be only estimates subject to substantial revision.
- Leakage at production sites would not affect the measurement of dry gas volumes, which are based on data for gas after passing through gathering and processing, and before entering transmission pipelines. Leakage from transmission pipeline systems within states are likely much too small to explain the large discrepancies for many states.
- Methane leakage from transmission would lead to positive discrepancies, e.g., for gas leakage between when dry gas production volumes are measured and when gas exports leave the state. However, some states show large negative discrepancies, so those can't be explained by methane leakage.

Given these factors, in particular the revisions to data over time, in using recent EIA data sets to allocate consumption in one state to production in the same state or other states, the results can only be approximate.

GIM ignores net storage withdrawals in tracing consumption quantities to production areas because the volumes of annual net storage withdrawals are generally small compared with the size of the data discrepancies described above. Annual net storage withdrawals are a shift of supply from one year to the next; these could be allocated indirectly to in-state production and/or imports in the prior year, but this would have only a minor effect on the results.

For 2018, GIM modeled volumes allocated to producing states in the contiguous U.S., when summed, are 1.0% below EIA data for contiguous U.S. dry gas production, showing a close match overall. For the five highest producing states, which accounted for 69% of U.S. dry gas production in 2018, the modeled values are within a range of +4.6% to -3.7% of the reported EIA data for each state. Significant differences for other major producing states, relative to EIA data, are: Colorado, -10.4%; West Virginia, +12.7%; Wyoming, -10.4%.

Because the model calculates the emissions intensities for gas imports and exports for each state, rather than absolute quantities of emissions, these discrepancies in attribution of volumes have a minor effect on the resulting emission intensities for each state's gas supply. For example, if the model's calculation of California's imports from Colorado were too high, and imports from Texas were too low, this would affect the emissions intensity allocated to California's gas consumption only insofar as the percentage leakage from production areas in Colorado is different from the percentage leakage from production areas in Texas.

6.2. Leakage due to gas imported from other countries

For natural gas that the U.S. imports from other countries, GIM does not make a detailed assessment of the leakage due to limitations of the current data available on methane leakage from oil and gas production areas outside the U.S. In the future, if more data becomes available for leakage from gas production outside the U.S., then GIM can be expanded to cover leakage from other countries.

For imported gas from other countries, GIM applies a default methane leakage rate from production areas, based on the weighted average leakage rate of 2.3% for all U.S. production areas covered by measurements shown in Table 3-1. As described in Section 5, this U.S. average is based on allocation of methane leakage from U.S. oil and gas production areas between co-products (dry gas, natural gas liquids, and crude oil).

GIM then applies the results of the energy-based allocation of methane leakage across products (dry gas, NGLs, and crude oil), using the U.S. average energy fraction from dry gas, which for 2018 was 53%. For 2018, the resulting methane emissions from production area leakage, per unit of dry gas delivered, is 228 g CH_4/Mcf dry gas. GIM applies this emissions rate to pipeline imports from Canada and Mexico, as well as liquefied natural gas (LNG) imports (e.g., imports by Massachusetts from Trinidad and Tobago).

GIM adopts this U.S. average value to apply to other countries because we are aware of few studies of methane leakage from production areas outside the U.S. As more data becomes available, GIM can be updated to incorporate this data to provide a clearer picture of methane emissions from gas imported from other countries.

There are studies that have drawn on official inventories for methane leakage from oil and gas production for countries that U.S. imports gas from, for example Canada and Mexico (Sheng 2017, Scarpelli 2020a, Scarpelli 2020b). However, studies taking measurements in production areas in Canada have measured or estimated greater methane leakage than operators have reported to the government (Johnson 2017, Zavala-Araiza 2018, Atherton 2017, O'Connell 2019, Wisen 2020). Because official inventories may underestimate actual methane leakage, GIM does not use official inventories to estimate methane leakage due to gas production from other countries.

More details on particular countries are below.

6.2.1.Methane leakage estimates for Canada

Canada has been by far the biggest source of gross gas imports into the U.S., responsible for 97% of gross gas imports in 2018. For Canada, we are aware of only one top-down survey of methane leakage in a gas-producing area in Canada, which covered the Red Deer production area; it did not calculate methane leakage as a percentage of gas produced (Johnson 2017). Methane leakage from production sites in the Red Deer area were also measured on-the-ground, estimating a mean leakage rate of ~3% of gas produced; the methane emissions measured in that study were stated to be within the confidence interval of the results in Johnson 2017 (Zavala-Araiza 2018).

The Red Deer area produced 3.5 Bcm of gas in 2016 (Johnson 2017), only 2.2% of Canada's marketable gas production of 159.8 Bcm (Statistics Canada 2017).

There are additional studies on methane leakage from oil and gas in Canada (Atherton 2017, O'Connell 2019, Wisen 2020) which show substantial leakage, but the studies did not calculate methane leakage rates as a percentage of production, across whole production regions.

Because the Red Deer production region is the only production area in Canada covered by top-down methane leakage measurements that estimated a percentage leakage, as far as we are aware, and because this region produces only a small fraction of Canada's gas, GIM uses the default leakage rate for U.S. (2.3%) to apply to all gas imports from Canada. In the future, if we become aware of additional data or more is published, then leakage rates can be assigned in GIM to Canada's production from particular regions.

6.2.2.Methane leakage estimates for Mexico

For Mexico, we are not aware of any top-down surveys of methane leakage in oil and gas production areas in Mexico. U.S. gross imports of gas from Mexico are very small—in 2018, only 3.3 Bcf out of total U.S. imports of 2,888 Bcf, and total U.S. consumption of 30,319 Bcf—so the leakage rate for Mexico's gas production would have a negligible effect on GIM results.

As for Canada, for gas production in Mexico, GIM applies the default leakage rate from the U.S. (2.3%).

7. Transmission leakage

7.1. Transmission and storage leakage rate

The model draws on a recent estimate of U.S. system-wide leakage rate from transmission and storage (T&S), based on a large number of measurements from compressor stations and other facilities that are part of the T&S system (Zimmerle 2015). That study estimated that the system wide T&S leakage rate is 0.35% of the gas transported. That study's estimate for U.S. leakage from transmission and storage was 27% lower than the value in EPA's most recent GHGI prior to that study.

EPA subsequently revised the GHGI methodology to be based on Zimmerle 2015 (EPA 2016a), and the T&S emissions estimates in Alvarez 2018 were also based on Zimmerle 2015. Thus, the Gas Index Model transmission leakage is closely aligned with both the EPA's GHGI and Alvarez 2018. We are not aware of subsequent measurements of T&S leakage that would provide a basis for updating the leakage rate from that estimated in Zimmerle 2015.

Zimmerle 2015 found that leakage from T&S occurs primarily from compressor stations, rather than directly from the pipelines. GIM calculates leakage from T&S based on the distance traveled from production areas to consumption centers; distance serves an approximate proxy for the number of compressor stations and other equipment in the transmission and storage system that are directly responsible for most leakage. Actual methane leakage from transmission and storage may depend not only on distance; some regions may have leakier T&S systems than others, but we are not aware of data to readily make such a distinction between regions.

The average distance that gas travels through the U.S. transmission system has been estimated to be 971 km (Littlefield 2019). Therefore, the Gas Index Model uses a leakage rate of 0.35% per 971 km = 0.36% per 1000 km.

We note that the Zimmerle 2015 estimate for T&S leakage also includes metering and regulation (M&R) stations at the city gate, where transmission pipelines connect to distribution mains. M&R leakage would be captured in measurements of city-level emissions, such as by airborne surveys (see Section 8). Also, we note that M&R leakage is counted in EPA GHGI as part of emissions from distribution, rather than from transmission.

However, EPA's GHGI estimates that < 0.01% of gas delivered to customers is leaked from M&R stations (EPA 2020, authors' calculation). Therefore, when combining estimates or measurements of transmission and distribution leakage from different sources, any double counting or missed counting of M&R leakage would have a negligible effect on the overall results.

7.2. Transmission distances

To calculate methane leakage due to transportation of gas through long-distance transmission pipeline networks, the model uses the model's attribution of gas consumed by each city to producing states. The model traces the paths taken in iteratively tracing back consumption to producing states. The model then calculates the distance from each consuming city to the states that were the immediate origin of the gas, and then continues to calculate the path distances between states along the path using the approximate center of each state. Distances are calculated using the haversine formula, which gives the shortest distance along Earth's surface between two points.

For example, the gas supply for city A within state B could come from production in state X via state Y. Thus, the path for the gas flow would be state X-state Y-city A. The transmission distance would be the distance from the center of state X to the center of state Y, plus the distance from the center of state Y to the center of city A.

When a state's consumption comes from a number of different importing paths, then the model calculates the average distance across all paths, weighted by the share of the state's consumption that each path supplies. (In each state, all cities are assumed to share the same supply of gas.)

Because the iterative process of tracing consumption back to producing states often includes loops, for calculating the distances above, the loops are excised to avoid inflating the distances due to artifacts of the modeling approach. For example, a possible path in the model results is M-N-O-P-N-R. This path passes through state N, and then loops around to pass through state N again, before ending in state R. In such a case, the model excises the loop, reducing the path to M-N-R.

The distances calculated are, on average, likely underestimates of actual distances because pipelines often follow less direct routes, either because of the landscape (e.g., to avoid mountains), or to connect with previously existing transmission pipelines. For routes of existing pipelines, see EIA's U.S. Energy Mapping System (https://www.eia.gov/state/maps.php).

In the 20 cities considered in the initial Gas Index, there is more than a 10-fold difference in the average distance that gas is transmitted to reach the cities, and therefore a corresponding difference in leakage due to transmission, ranging from 0.07% for Philadelphia, PA, to 0.8% in Portland, OR.

7.3. Validation of transmission distances

The model's weighted average distance that US gas traveled from production areas to consuming states was 831 km. This is similar to the average value of 971 km reported by NETL (Littlefield 2019).

The method described above for validation assumes zero distance for gas that is consumed in the same state that it is produced. To calculate those in-state transmission distances realistically would require simulating the transmission proportionally to all the state's consuming centers.

When calculating transmission leakage for particular cities, the Gas Index Model calculates transmission leakage for each city for the gas produced in the same state; it assumes the gas originates in the state's centroid, and then calculates the distance from the state's centroid to the city of interest. For the initial 37 cities in the Gas Index, the average transmission distance calculated was 993 km. This average is not weighted by the city's consumption, and the average for all US cities may be somewhat different. Nonetheless, this indicates that the model's calculated transmission distances are similar to NETL's estimated U.S. average transmission distance.

8. Distribution mains

GIM's first component of gas leakage within cities is from distribution mains, which are pipelines that branch off from long-distance transmission lines, to carry gas to consumers. Distribution mains typically run under city streets, and smaller pipelines known as service lines branch off from them, running onto each customer's property, up to the customer's gas meter.

Using data from PHMSA on the properties of each gas utility's pipeline system, and EIA data on gas deliveries, it is possible to estimate methane leakage from each utility's distribution mains.

8.1. Measurements in Weller 2020 compared with EPA's GHGI

A campaign of measurements from mobile sensors mounted on cars took extensive measurements of methane concentrations within 12 U.S. cities from 2013 to 2017 (von Fischer 2017, Weller 2018, EDF 2018). Detailed analysis of those measurements attributed methane enhancements to leakage from distribution mains of particular materials and ages (Weller 2020). These measurements—far more extensive than previous measurements (Lamb 2015) used as the basis for EPA's GHGI emissions from distribution mains—showed a right-skewed distribution of emissions rates that included super-emitters, as found in leakage studies of other parts of the fossil gas system.

Weller 2020 used detailed maps of distribution mains in four cities to estimate the number of leaks per mile and the size of leaks, for each of the main materials used for these pipelines. Based on these relationships between materials and leakage rates, Weller 2020 then used PHMSA data (PHMSA 2020a) to estimate nationwide values for distribution mains, for the number of leaks and the methane leakage rate per leak (g CH_4/min/leak).

The nationwide quantity of leakage from distribution mains that Weller 2020 estimated was 4.8 times higher than the quantity in EPA's GHGI. For further comparison, see section 8.2.4, "Comparison of studies of leakage from distribution mains."

For distribution mains of each material, Weller 2020 reported mean values for the number of leaks per mile and the methane leakage rate per leak (g CH4/min/leak).

8.2. Calculation of distribution mains leakage in GIM

GIM uses each LDC's mileage of distribution mains of particular materials as the basis for estimating methane leakage from these pipelines. This follows the practice in EPA's GHGI (EPA 2016b). This approach is also supported by the results of Weller 2020, which found a relationship between the annual leakage per mile (g CH_4/mile of pipeline/year) and the material of pipeline. Weller 2020 also found a relationship between the annual leakage per mile (g CH_4/mile of pipeline/year) and the age of pipelines. Since different materials tended to be used by LDCs at different times, then material is correlated with age.

PHMSA data used by GIM reports the length of pipelines of particular materials, and also reports length of pipelines by decade installed (PHMSA 2020a). However, the PHMSA data does not report both at the same time—e.g., it does not report the miles of cast iron pipelines that were installed in the 1940s. Weller 2020 used a statistical technique to infer the likely values for both material and age for the nationwide PHMSA data set. However, we are not able to apply that technique, and it may be less reliable when applied to individual LDCs.

Due to the limitations of the PHMSA data, as well as the standard practice in EPA's GHGI, GIM uses material alone as the basis for estimating leakage from distribution mains. See sections 8.5 and 8.6 below for more explanation regarding earlier studies and caveats.

For each material M, GIM calculates the estimated annual quantity leaked per mile as:

$$methane\ leaked\ per\ mile_M = number\ of\ leaks\ per\ mile_M \times mean\ size\ of\ leak_M$$

GIM applies these leakage rates per mile to calculate leakage for each utility's network of distribution mains, using PHMSA reports for the mileage of each mains for each material. Thus, for each utility, for material M, the estimated annual leakage is:

$$leakage\ quantity_M = mains\ miles_M \times methane\ leaked\ per\ mile_M$$

PHMSA reports the miles of mains for a large number of different materials. Weller 2020 grouped the materials into a smaller number of categories, and GIM estimates follow that categorization, as shown in Table 8.2-1.

Weller 2020 did not distinguish between cathodically protected steel pipelines and not cathodically protected pipelines because of limitations of the data available from LDCs that cooperated with the study. Therefore, Weller 2020 only distinguished steel pipelines on the basis of being coated or not coated (bare). On the other hand, EPA and other studies of distribution pipeline leakage generally distinguish steel pipelines on the basis of cathodic protection, and not on whether they are coated. (Coatings and cathodic protection are both intended to prevent corrosion.)

Table 8.2-1. Categorization of distribution pipelines by material in GIM, following Weller 2020 categorization. Names of categories and miles of pipelines from PHMSA 2020a.

GIM category	PHMSA category	Miles of pipeline	% of total miles
Cast iron	Cast iron (CI)	22,860	1.8%
	Reconditioned cast iron (RCI)	28	0.0%
	Ductile iron (DI)	513	0.0%
Bare steel	Bare steel, cathodically protected	10,771	0.8%
	Bare steel, not cathodically protected	33,270	2.6%
	Copper	12	0.0%
Coated steel	Coated steel, cathodically protected	463,849	35.6%
	Coated steel, not cathodically protected	19,082	1.5%
	Other	1,313	0.1%
Plastic	Plastic	750,351	57.6%
Total		1,302,051	100.0%

As shown in Table 8.2-1, most bare steel pipelines (76%) are not cathodically protected, whereas coated steel pipelines are nearly all (96%) cathodically protected. Thus, coated steel is roughly synonymous with cathodically protected steel, and bare steel is roughly synonymous with not cathodically protected steel.

Although both coatings and cathodic protection are intended to prevent corrosion, Weller 2020 found little difference in the mean leakage rates of coated steel and bare steel. For more details, see Section 8.5 below, in particular Table 8.5-3.

8.3. Comparison of GIM results with Weller 2020

8.3.1. Comparison of number of estimated leaks

Using the mean values from Weller 2020—for number of leaks per mile, and mean leakage rate (g methane per minute per leak)—to estimate the number of leaks for each utility's distribution mains, GIM estimates that U.S. distribution mains (including Alaska and Hawaii) in 2017 had 662,000 leaks, compared with 659,100 in Weller 2020; thus, the modeled U.S. total number of leaks is 0.5% higher than in Weller 2020. Therefore, we conclude that using the mean values in Weller 2020 closely replicates the more complex method used in Weller 2020 to derive the mean values.

8.3.2. Comparison of volume of methane leaked

GIM uses the mean values from Weller 2020—for both the mean number of leaks per mile for each material, and the mean size of leak for each material—to model the quantity of methane leaked by each utility. By this method, GIM estimates total leakage from U.S. distribution mains in 2017 of 691 Gg CH_4/y, compared with 690 Gg CH_4/y in Weller 2020. Thus, the GIM U.S. total is very close to the value in Weller 2020.

The estimates of total number of leaks and total leakage suggest that the use of mean values from Weller 2020 for each material provide a reasonable method for estimating leakage for each utility that produces nationwide results close those reported in Weller 2020.

GIM results for individual utilities are only estimates, since individual utilities may have distribution systems that differ from each other in additional ways, such as by:

- natural hazards that may affect distribution mains, e.g., earthquakes
- climate, e.g., hard freezes can cause “frost heave,” in which ice forms underground and stresses pipes (Rosenfeld 2015)
- the age of pipelines; some utilities may have older pipelines of each material than the mean used to estimating leakage in GIM

- management/ownership history
- regulatory frameworks

8.4. Comparison with PHMSA data for number of leaks

PHMSA data includes the number of leaks repaired in distribution mains during each annual reporting period; in 2017, this was 124,438 leaks (PHMSA 2020a). PHMSA also reports the number of known leaks remaining at the end of each year, which for 2017 was 104,133 leaks. However, the data doesn't specify whether the known leaks remaining are for mains, services, or both types of pipelines.

In PHMSA data for 2017, of the total number of repaired leaks, 24% were on mains and 76% were on service lines. As a rough estimate, if the leaks remaining follow the same pattern (24% on mains and 76% on service lines), there would be ~25,000 known leaks remaining on mains. This would bring the total number of known leaks on mains in 2017 to ~150,000.

The number of leaks estimated in Weller 2020 is a factor of 4.3 higher than the leaks reported by PHMSA (including both leaks repaired and reported leaks remaining unrepaired). This suggests that, on average, utilities report only a fraction of the leaks in their systems, perhaps ~25% of the actual number of leaks.

Also, Weller 2018 used mobile measurements of methane concentrations to identify leaks from distribution systems and compared them against leaks known by utilities. That study estimated that utilities are aware of only 35% of the leaks that could be identified by such a mobile survey.

8.5. Comparison of studies of leakage from distribution mains

Here we compare the Weller 2020 results against previous studies, including a study by the Gas Research Institute in 1996, commissioned by and published by the EPA (EPA 1996a). This 1996 study served as the basis of EPA's GHGI methane leakage estimates for distribution mains until 2016, when the methodology was revised to rely on a newer study, Lamb 2015 (EPA 2016b).

Weller 2020 estimated much higher nationwide leakage from distribution mains than in both EPA 1996a and Lamb 2015. There are two primary reasons for the higher estimates in Weller 2020:

- **Direct estimate of leaks per mile:** EPA's GHGI and Lamb 2015 used reports from utilities for the number of leaks and made assumptions about the percentage of leaks that utilities were aware of; Lamb 2015 assumed utilities were aware of 85% of the leaks in distribution mains. However, a subsequent study with more extensive measurements in two U.S. cities, which involved coordination with utilities to compare detection of leaks, estimated that utilities were reporting only 35% of leaks (Weller 2018). If the Lamb 2015 estimate that utilities are aware of 85% of leaks is too high, as suggested by Weller 2018 and Weller 2020, then the Lamb 2015 results for total methane leakage would be too low. This is because there would be more leaks than assumed in Lamb 2015. In Weller 2020, rather than making an assumption about the number of leaks per mile or the percentage of leaks that utilities are aware of, directly measured the number of leaks per mile of pipeline. Compared with earlier studies, Weller 2020 found fewer leaks per mile for two materials (cast iron and unprotected steel) used predominantly in older pipelines. But Weller 2020 found many more leaks per mile in the materials used for newer pipelines, protected steel and plastic, which most of the existing system is now built from (see Table 8.5-1). For discussion of how repair programs may have changed the number of leaks per mile for different materials, see Section 8.6.
- **More extensive measurements:** Lamb 2015 was based on measurements of 142 leaks from distribution pipelines, whereas Weller 2020 was based on measurements of 4,220 leaks. When the distribution of emission sources is right skewed and includes super-emitters, as found in Weller

2020, then a large number of measurements are needed to better characterize the distribution; in such a case, calculating a mean based on a small number of measurements is likely to lead to an underestimate (Zimmerle 2015, Brandt 2016). In Weller 2020, all materials had higher mean emission rates per leak than in Lamb 2015; in particular, for plastic pipelines, which are the predominant type for newer pipelines, Weller 2020 found the mean emissions rate per leak (g CH_4/leak/min) to be 6-fold higher than in Lamb 2015 (see Table 8.5-2).

Another survey of distribution mains was conducted by the Gas Technology Institute (GTI) in California in 2015 (Wiley and Adamo 2016). The study measured the methane leakage rates (g CH_4/leak/min) for individual leaks in two materials, unprotected steel and plastic. The GTI study did not undertake a survey of leaks that would allow estimation of the number of leaks per mile, and therefore this study is not shown in Table 8.5-1. GTI found leakage rates that were about half the rate of Weller 2020, but higher than Lamb 2015—in particular for plastic mains, the GTI 2016 value was ~3 times higher than the Lamb 2015 value (Table 8.5-2).

GTI 2016 values are lower than that of Weller 2020, perhaps due to differences in region (covering only California) and/or due to more limited measurements (87 leaks) that would not characterize the heavy tail of super-emitters as well as Weller 2020. Also, GTI 2016 measurements were random selections of leaks already identified by utilities that commissioned the study, rather than surveys of all leaks that could be detected, as in Weller 2020.

Table 8.5-1. Distribution mains number of leaks per mile and mileage of pipelines. Pipeline miles from PHMSA 2020a, using the material categorization in Weller 2020. Values for EPA 1996 from EPA 1996c, which did not report the quantity of leakage per leak for cast iron; calculated based on mileage in EPA 1996c Table 8-4 and equivalent leaks in EPA 1996c Table 9-1. EPA 1996c did not report the number of equivalent leaks for cast iron. CP = cathodically protected.

Material	EPA 1996 leaks per mile (estimated)	Lamb 2015 leaks per mile (estimated)	Weller 2020 leaks per mile (measured)	Mains miles in 2018	Mains miles in 2018 (%)
Cast iron	Not estimated	2.88	1.00	23,401	1.8%
Non-CP steel	2.13	2.51			
Bare steel			0.51	44,062	3.4%
CP steel	0.15	0.11			
Coated steel			0.61	484,772	37.1%
Plastic	0.16	0.05	0.43	753,222	57.7%

Table 8.5-2. Distribution mains mean methane leakage per leak (grams CH_4/leak/min) and number of leaks measured (n). Values for EPA 1996 from EPA 1996c Table 8-1, which did not report the quantity of leakage per leak for cast iron.[8] GTI 2016 (Wiley and Adamo 2016) values were originally reported as cubic feet per hour. CP = cathodically protected.

Material	**EPA 1996**	**Lamb 2015**	**GTI 2016**	**Weller 2020**
Cast iron	n/a n = 21	0.90 n = 14	Not measured	1.72 n = 1,664
Non-CP steel	1.94 n = 20	0.77 n = 74	0.96 n = 23	
Bare steel				2.24 n = 826
CP steel	0.77 n = 17	1.21 n = 31	Not measured	
Coated steel				2.00 n = 911
Plastic	3.74 n = 6	0.33 n = 23	1.10 n = 16	2.03 n = 819

Table 8.5-3 compares results for the annual quantity of methane leaked per mile of distribution mains, for each material. For cast iron and bare steel, the mean leakage rates (annual kg methane leaked per mile of pipeline) from Weller 2020 are lower than that of the GHGI (80% and 70%, respectively, of the GHGI values); however, for these materials, the GHGI values are within the Weller 2020 95% confidence interval.

However, for coated steel and plastic, the Weller 2020 mean leakage rates (annual kg methane leaked per mile of pipeline) are significantly higher than in GHGI; for coated steel, the Weller 2020 mean leakage

[8] We note that values for the EPA 1996 study reported in Lamb 2015 closely match our calculations for two materials (unprotected steel and protected steel). For cast iron, EPA 1996c did not report the average size of leaks; Lamb 2015 estimated the size of leaks based on their own estimates for the number of leaks per mile. For plastic, EPA 1996c did report the average size of leaks in Table 8-1, which was 3.74 g/min; however, Lamb 2015 reported a significantly lower value of 1.88 grams methane per minute that was attributed to EPA 1996c. We are not aware of a reason for this discrepancy; we have reported here the sources of data in EPA 1996 used in our calculations.

rate is 6.6 times higher than in GHGI, and for plastic 15.9 times higher. The higher leakage rates (annual kg leaked per mile of pipeline) for these latter materials are the main contributors to the total leakage from all distribution mains in Weller 2020 being 4.8 times higher than in GHGI (for 2017, 690 kilotons in Weller 2020 compared with 143 kilotons in GHGI published in 2019).

Table 8.5-3. Distribution mains leakage per mile (annual kilograms methane per mile). For steel pipelines, Weller 2020 distinguished between coated and uncoated steel due to limitations of the data available from utilities that cooperated with the study. Previous studies had distinguished steel pipelines based on cathodic protection, categorizing pipelines as protected or unprotected. For cast iron, EPA 1996c did not report the quantity of leakage per leak, nor the number of equivalent leaks for cast iron, but did report the leakage per mile in EPA 1996c Table 9-1. For other, values below calculated based on miles in EPA 1996c Table 8-4 and equivalent leaks in EPA 1996c Table 9-1.

Material	EPA 1996	Lamb 2015	EPA GHGI 2020	Weller 2020
Cast iron	4,608	1,362	1,157	904
Unprotected steel	2,127	1,016	861	
Bare steel				600
Protected steel	59	70	97	
Coated steel				641
Plastic	317	9	29	459

Due to the predominance of coated steel and plastic distribution mains (94.8% of all mains in 2018), the leakage rates for cast iron and bare steel (5.2% of all mains) have relatively little effect on the estimates for nationwide emissions from distribution mains. Therefore, higher overall leakage rates based on the Weller 2020 values are due to the higher leakage rates estimated in Weller 2020 for coated steel and plastic pipelines, rather than the values for cast iron and bare steel.

EPA 1996c, based on much earlier measurements, reported higher leakage rates for older materials (cast iron and unprotected steel), compared with Weller 2020. This may have reflected that there were older, leakier pipes of these materials that were in service at the time of the measurements used in EPA 1996c, which were taken in the early 1990s. Since the 1990s, there have been extensive efforts to replace older distribution pipelines. For example, PHMSA describes the efforts to replace cast iron pipelines: "The amount of cast and wrought iron pipeline in use has declined significantly in recent years, thanks to increased state and federal safety initiatives and pipeline operators' replacement efforts. Twenty-two states and one territory have completely eliminated cast or wrought iron natural gas distribution lines within their borders" (PHMSA 2020b).

EPA 1996c relied on company data regarding the number of leaks discovered and repaired to estimate the total number of leaks (as shown in Table 8.5-1). If there were additional leaks that were not discovered by utilities, then the EPA 1996c method would likely underestimate the number of leaks, and therefore the total volume of gas that leaks.

8.6. Distribution mains: Explanations and caveats

Weller 2020 found that older pipelines tended to have a higher number of leaks per mile, for any given material, and also across all materials (Weller 2020, Figure 2).

PHMSA reports data on materials of pipelines, and installation decades of pipelines, but not both together. Also, the installation decades are distinguished only back to 1940s, and all pipelines prior to that are lumped together in one category. Therefore, attempting to use PHMSA data on installation decades

may underestimate the number of leaks from the oldest pipelines, for example in cities such as Boston that have older pipeline systems (Phillips 2013, Weller 2020).

Pipeline materials tended to be used in distinct phases, so the oldest remaining pipelines are typically cast iron, the next oldest are bare steel, then coated steel, and the most recently installed pipelines are mostly plastic. Thus, pipeline material and age are correlated.

For the predominant materials for newer pipelines—coated steel and plastic—Weller 2020 found these pipelines have significant number of leaks per mile starting from the time of installation (~0.3 leaks per mile), and that the number of leaks per mile increases ~60-70% during the first 50 years of operation.

However, Weller 2020 did not find that age was predictive of the size of individual leaks. Weller 2020 noted: "Pipeline age, diameter, and pressure were not predictive of emissions [per leak]. As a result, we follow the GRI/EPA 1992 and Lamb 2015 studies and consider differences in emissions factors between materials."

Thus, GIM uses the Weller 2020 values for each material for the mean number of leaks per mile and the mean size of leak, without consideration of age. As shown in Section 8.2.3, this leads to nationwide results in GIM that are very close to those of Weller 2020.

Many LDCs have prioritized replacing older distribution mains, in particular cast iron (PHMSA 2020b). Such programs prioritizing replacement of the oldest pipelines may have changed the leakage measured from cast iron pipelines, so that studies drawing on more recent measurements would find a lower annual leakage rate (g CH_4/mile of pipeline) than in earlier measurements. It is possible that prioritizing replacement of the oldest pipelines may have led to deprioritizing repairs of newer pipelines with smaller leaks that are not hazardous.

9. Service lines

Service lines connect distribution mains to customers, running from the mains to the customer gas meter. (Any leakage that occurs after gas passes through the customer gas meter is known as "behind-the-meter leakage; see Section 8.6.) GIM estimates leakage from service lines using a material-based approach, which is also how EPA's GHGI estimates service line leakage (EPA 2020b).

We are not aware of an extensive campaign to measure leakage from service lines, to complement the EDF-Google campaign that measured leakage in cities and was used to estimate leakage from distribution mains (Weller 2020). Therefore, GIM uses emissions factors for service lines, of each material, from EPA's GHGI, as shown in Table 9-1 (EPA 2020b).

Table 9-1. Annual methane leakage from service lines compared with leakage from distribution mains. EPA GHGI 2020 methane leakage per service and number of service lines, as well as mains methane leakage rates, are from EPA 2020b. Average length of service lines and mileage of service lines are authors' calculations from PHMSA data for 2018 (PHMSA 2020a). The average length of service line, nationwide, was 70.9 feet (calculation based on PHMSA 2020a).

Material	GHGI 2020 methane leakage per service line (kg/y)	Number of service lines (millions)	Inferred EPA services methane leakage rate (kg/mi)
Unprotected steel	14.5	2.920	1,080
Protected steel	1.3	13.249	97
Plastic	0.3	50.414	22
Copper	4.9	0.731	365

Utilities report to PHMSA the number of service lines of each material, and also the average length of all service lines. From this data set, for each utility, the model calculates the mileage of service lines of each material. Then the model applies methane leakage rate per mile for each material. This approach is taken because some LDCs have substantially longer service lines, on average, than other LDCs. The average is 70.9 feet per service line, but the range for the middle 50% of values is from 40 feet to 100 feet per service line.

Therefore, GIM uses data for each utility on the number of service lines and length of services lines, and applies leakage rates per length, as shown in Table 9-1. In this way, the leakage calculations more closely reflect the properties of each LDC, rather than being a nationwide average.

In GIM's method for service lines, for each LDC *L* and each material *M*, the leakage is:

$$\begin{aligned} &service\ line\ leakage_{UM} \\ &\qquad = number\ of\ service\ lines_{UM} \times average\ length\ of\ service\ lines_{U} \\ &\qquad \times leakage\ rate\ per\ mile_{UM} \end{aligned}$$

Where:

- For each utility, number of service lines for each material and average length of service lines from PHMSA 2020a.
- For each material, leakage rate per mile of service lines based on leakage rate per mile of distribution mains of the same material from EPA's GHGI, as shown in Table 9-1.

For each utility, the leakage quantities from the service lines of each material are summed to calculate the utility's estimated total service line leakage.

PHMSA divides service lines into a larger number of types of materials than used in EPA's GHGI, so GIM groups service lines into the same categories that EPA uses. It is ambiguous how to categorize some of the entries in PHMSA's data, so the categories chosen are shown in Table 9-2. In particular, the category "other" is grouped with plastic, because plastic has the lowest emissions factor in EPA's GHGI, so this is the most conservative approach for assigning these pipelines, leading to the lowest leakage.

Table 9-2. Service lines by material and categorization into groups used by EPA.

PHMSA material	PHMSA cathodically protected?	PHMSA coated?	% of U.S. service line length	EPA category assigned in GIM
Plastic	n/a	n/a	73.9%	Plastic
Steel	Y	Y	18.4%	Steel, protected
Steel	Y	N	0.5%	Steel, protected
Steel	N	Y	1.8%	Steel, unprotected
Steel	N	N	1.8%	Steel, unprotected
Copper	n/a	n/a	1.1%	Copper
Cast iron	n/a	n/a	< 0.1%	Steel, unprotected
Other	n/a	n/a	2.4%	Plastic

9.1. Measurements of service line leakage

Below is a summary of past studies with measurements of service lines that we are aware of.

The GRI study commissioned by, and published by, EPA in 1996 measured leakage from service lines, calculated mean sizes of leaks for four different materials (EPA 1996c). Those values are shown below in Table 9.1-1.

Lamb 2015 reported 69 measurements of service line leaks to estimate the size of each leak (g CH_4/min). The study estimated the number of leaks per service line. The results reported in Lamb 2015 were used in EPA GHGI to calculate leakage from service lines, from 2016 onward (EPA 2016b).

However, Lamb 2015 did not conduct a survey of service line leakage that would allow for estimating the number of leaks per service line, or per mile of service lines. Since Weller 2020 found much higher leakage rates per mile for distribution mains than in Lamb 2015 (see Section 8.2.4), then the service line leakage rates in Lamb 2015 may likewise be significant underestimates. That is, a more extensive measurement campaign for service line leakage, like the survey of distribution main leakage used in Weller 2020, may show significantly higher leakage than in Lamb 2015.

In 2016, GTI reported measurements of the sizes of 39 known leaks on service lines in California (Wiley and Adamo 2016). However, that study did not conduct a measurement campaign to measure the number of leaks per service line, so the measurements can't be used directly to estimate overall leakage quantities from service lines. Results from this study are not used as inputs to GIM.

Weller 2018 measured methane leakage in two cities using car-mounted sensors to conduct a survey along roads, reporting that the measurements may have picked up leakage from service lines. (The cities in which the measurements were taken were not specified in Weller 2018, to comply with nondisclosure agreements with the local distribution companies that participated.) However, the study did not distinguish distribution mains leakage from service line leakage.

As shown in Table 9.1-1, the existing measurement studies of service lines are based on relatively small number of measurements for each material, compared with studies such as Weller 2020 on distribution mains. Therefore, the existing measurements of service lines may not fully represent super-emitters (emissions on the high end of the distribution), and thus have underestimated total emissions from service lines.

In EPA 1996c, the study authors noted that there were a small number of measurements, and that there was one outlier (for emissions from plastic distribution mains) that was much higher than other measurements, which made the average for that category ~5-fold higher than it otherwise would have been. The study performed "statistical outlier tests" to determine whether the large emissions from one measurement "could justifiably be omitted from the data set." The study concluded that the outlier could not be excluded. However, the study did not seem to recognize the phenomenon of super-emitters, and how they would strongly influence the total leakage. Instead of trying to exclude outliers with very high emissions, more recent studies have recognized that the emissions size and frequency of super-emitters can be represented more accurately by performing more measurements (Brandt 2016). Or if more measurements are not feasible, the available data can be fed into a statistical model to simulate sampling to estimate the true contribution from super-emitters (Zimmerle 2015).

Table 9.1-1. Leakage rates for service lines (grams methane per leak per minute) and number of measurements taken (n). Average across studies is weighted based on the number of measurements in each study. Data sources are EPA 1996c, Lamb 2015, and Wiley and Adamo 2016. Conversion from scf to mass based on the density of methane (19.3 kg/Mcf).

Material	EPA 1996	Lamb 2015	GTI 2016	Weighted average
Unprotected steel	0.74 n = 13	0.33 n = 19	0.494 n = 18	0.50 n = 50
Protected steel	0.34 n = 24	0.13 n = 12	n/a	0.27 n = 36
Plastic	0.09 n = 4	0.13 n = 38	0.619 n = 21	0.29 n = 63
Copper	0.28 n = 5	n/a	n/a	0.28 n = 5

9.2. Distribution service lines: caveats

Weller 2020, analyzing extensive measurements of leakage attributed to distribution mains, found that leakage rates for plastic pipelines than in prior studies, including Lamb 2015. Lamb 2015 is currently used as the basis for EPA's GHGI leakage rates for both distribution mains and service lines, as described in Section 1.

Therefore, we believe that the emissions factors for distribution service lines that are used in EPA's GHGI, and also used in GIM, are likely underestimates of actual methane leakage from service lines that would be found with an extensive measurement campaign.

If additional data becomes available in the future for more measurements of methane leakage from service lines, GIM can be updated to incorporate such data.

10. Allocating distribution pipeline leakage by sector

In GIM, the leakage from distribution pipelines (mains and service lines) are combined, and then allocated between five sectors (residential, commercial, industrial, electric, and transportation), based on the consumption of gas in each sector.

All gas delivered by companies that own local distribution systems are assumed to pass through the local distribution system. However, some gas companies own both transmission and local distribution systems, and sell a significant portion of gas directly from transmission lines (e.g., to large industrial consumers and power plants), and the remainder is delivered through local distribution.

The assumption above—that all gas sold by companies that own local distribution systems would pass through local distribution—does not affect the calculations in GIM for the total quantity of methane leaked (Gg CH_4/year) from distribution pipelines. In GIM, distribution pipeline leakage is based on the miles of pipeline of each type (e.g., cast iron), and is not based on the volume of gas that passes through the pipelines.

By assuming that all gas sold by a gas company passes through its local distribution pipelines, and allocating methane leakage by sector, GIM may be overestimating leakage for electric and industrial customers, and underestimating leakage for residential and commercial customers. This is because the actual quantities of gas passing through local distribution systems may be lower than the total sold to customers, when a gas company sells some of its gas directly to large customers from its transmission lines. If the gas passing through local distribution systems is smaller than assumed in GIM, due to direct sales to electric and industrial consumers, then the total volumes would be lower and the corresponding leakage rage (g CH4 leaked/Mcf gas delivered) would be higher for the gas that does pass through local distribution pipelines.

From EIA data on gas sales by sector, and PHMSA data on which companies own local distribution networks, we are able to isolate the companies that report to EIA that do *not* own local distribution networks. In 2018, these non-LDC-owning companies were responsible for 71% of total gas sales to the electric sector and 47% of total gas sales to industrial customers. These values are lower bounds on how much gas for these sectors is sold directly, without passing through local distribution systems, since companies that do own LDCs as well as transmission pipelines may be selling gas directly from transmission lines to electric and industrial customers.

If we become aware of additional data that would allow for allocating distribution pipeline leakage in a different way between sectors, to account for a portion of electric and industrial gas deliveries that may pass through local distribution systems, we will modify GIM in the future.

11. Customer gas meters

The Gas Index Model draws on a 2019 Gas Technology Institute measurement survey commissioned by the Department of Energy "to improve the characterization of methane (CH_4) emissions currently detailed in the U.S. Environmental Protection Agency (EPA) Greenhouse Gas Inventory (GHGI) for categories of assets within the Natural Gas (NG) distribution system" (Moore 2019). Moore 2019 found much higher leakage rates than in EPA's GHGI (EPA 2020a).

We note that the Gas Technology Institute is the successor to the Gas Research Institute (GTI 2020), which conducted a 1996 study (EPA 1996a, EPA 1996b) commissioned by the EPA. EPA's GHGI relied on this study for customer gas meter leakage up until the 2016 edition of GHGI (EPA 2016b), and which GHGI continues to rely on for many parts of the GHGI (EPA 2020b).

For reference, we first describe the calculations in EPA's GHGI for customer gas meter leakage, and then describe GIM's approach based on Moore 2019.

11.1. Customer gas meter leakage in EPA's GHGI

EPA's GHGI assumes that each customer has a single meter (EPA 2016b). Counts for number of meters in recent years are derived from EIA 176, as follows (EPA 2020b):

Commercial/industrial meters:

- "Total number of commercial + industrial natural gas consumers in year N."

Residential meters:

- GHGI only counts residential customer gas meters that are outdoors in calculating gas leakage, explaining that GHGI "assumed indoor meter emissions were negligible because leaks within the confined space of a residence are readily identified and repaired" (EPA 2016b).
- The calculation is: "[Number of residential natural gas consumers in year N (EIA 2019g)] * [Weighted average percentage of meters outdoors (GRI/EPA 1996)]" (EPA 2020b).
- For 2018, EIA reported 62,837,177 residential customers, and GHGI assumes that the number of residential meters is equal to the number of customers. GHGI stated that in 2018 there were 55,300,313 outdoor meters.

To calculate the quantity of methane leaked, GHGI multiplies the count of customer gas meters above by an emissions factor for each category of meter (EPA 2020b), as shown in Table 11.1-1. For residential customer gas meters, GHGI only counts the customer gas meters that are outdoors (88% of total residential gas meters).

As shown in Table 11.1-1, we calculate a percentage leakage rate from meters for each category based on GHGI values for leakage. This assumes gas delivered to customers contains 95% methane by volume, and a density of methane of 19.3 kg/Mcf. For separating leakage from commercial and industrial meters, we use the percentage of customers (and therefore meters) that are commercial, which was 96.8% for 2018 (EIA 2020b).

Table 11.1-1. Methane leakage from customer gas meters in EPA GHGI 2020, and calculated percentage leakage rate.

Meter type	Number of meters	Leakage rate (kg methane per meter per year)	Total leakage from meters (kilotons methane / year)	Gas delivered (Bcf / year)	Percentage leakage rate

Residential	55,300,313†	1.5	82.3	4,996	0.090%
Commercial	5,515,841	9.7	54.3	3,515	0.084%
Industrial	184,943	9.7	1.8	8,377	0.001%
Electric	1,851	n/a	n/a	10,993	n/a

† The value shown for residential gas meters includes only the gas meters outdoors, because EPA assumes gas meters that are indoors do not leak.

Therefore, in EPA's GHGI, residential and commercial gas meters leak a similar percentage of gas flowing through them. Based on the emissions factors used in GHGI, industrial meters have a very leakage rate as a percentage of gas flowing through them; the percentage leakage rate for commercial meters is 72 times higher than for industrial meters.

We note that other studies, as described below, have found higher leakage rates than the values used in EPA's GHGI 2020.

11.2. Customer gas meter leakage in Moore 2019

As far as we are aware, Moore 2019, introduced above, is the most extensive survey to date for commercial and industrial gas customer gas meters. The study measured methane leakage from 523 customer gas meters, both industrial (186) and commercial (337), across all regions of the contiguous U.S.

Moore 2019 measured meters themselves as well as multiple components from the system surrounding the meters (including valves, flanges, and tees), and found that meters rarely leaked methane, whereas the other system components were usually the sources of the leaks. The study referred to the leakage from the meter itself and the components around the meter as leakage from the "meter set." Here, we refer to all of this leakage as simply leakage from meters.

In Moore 2019, 84% of meters showed an indication of leakage, with some methane being detected; however, the emissions were able to be quantified for only 43% of meter sets. The distribution of leakage was heavy tailed; about 10% of the meters were responsible for ~70% of the overall emissions (Moore 2019, Figure 14). Thus, Moore 2019 found that a small fraction of gas meters were super-emitters that were responsible for the majority the emissions, similar to the pattern of leakage observed in other parts of the natural gas system (Brandt 2016, Duren 2019).

Also, Moore 2019 used a Bayesian statistical approach that they argue is better suited to model leakage from meters, "due to the skewness of the emission rate data." This statistical model uses the data from measurements to estimate a probability of finding a particular leakage rate for a randomly chosen meter. This approach is different from EPA 1996b, which simply took the mean value of measurements.

The measurements in Moore 2019 suggest that EPA's GHGI is greatly underestimating methane leakage from industrial and commercial meters. Moore 2019 notes: "The current factor used in the GHGI for a combined nationwide industrial/commercial meter category is 9.7 kg CH_4 meter^{-1} yr^{-1}. Our data indicate that this nationwide value may be closer to 78.9 kg CH_4 meter^{-1} yr^{-1}." Thus, the new measurements suggest that, nationwide, the leakage rates for commercial and industrial meters are a factor of 8.1 higher than the value used in GHGI.

For commercial customer gas meters specifically, Moore 2019 calculated a mean leakage rate of 57.4 kg CH_4 meter^{-1} yr^{-1}, which is 5.9 times higher than the leakage rate of 9.7 kg CH_4 meter^{-1} yr^{-1} used in GHGI (EPA 2020b).

In other parts of the natural gas system, newer measurements and more sophisticated statistical techniques that take better account of the skewed distribution of emitters, find larger leakage quantities overall, and that a small number of super-emitters responsible for a large share of the overall emissions. For distribution mains, Weller 2020 (based on its investigated sample) estimated a nationwide leakage rate 4.8 times higher than in GHGI. It appears that a Moore 2019 has shown a similar phenomenon for its investigated sample of commercial customer gas meters.

Leakage rates from the measurements we are aware of for commercial meter leakage are shown in Figure 11.2-1. Prior to 2016, EPA's GHGI used the value from the 1996 study conducted by the Gas Research Institute; from 2016 onward, GHGI has used a significantly higher leakage rate for commercial meters based on a 2009 GTI study (EPA 2016b). The results indicate that significant revisions in the leakage rates can occur.

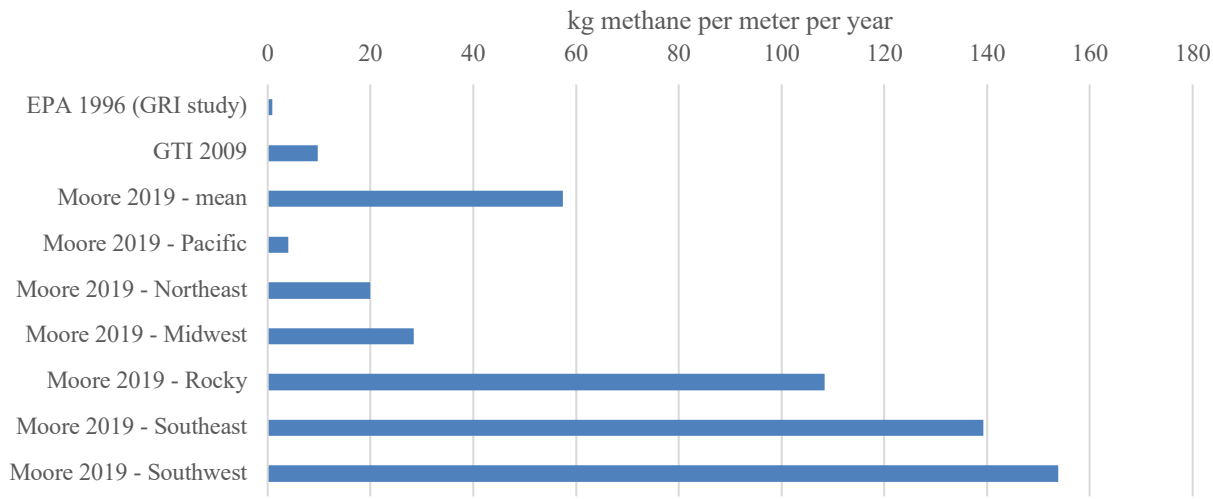
Moore 2019 found large differences in meter leakage rates between regions. Moore 2019 took measurements across the U.S., reporting emissions for six different regions. The Pacific region had the lowest leakage rates, similar to the value used in the GHGI following the 2016 update; the mean commercial meter leakage rate for this region was 4.0 kg/meter/year. Other regions had significantly higher leakage. The highest leakage rate for commercial customer gas meters was in the Southwest region, with a mean rate of 153.9 kg/meter/year, 38-fold higher than the Pacific region rate.

Moore 2019 notes that the study found clear differences in leakage rates between types of gas meters; the three most common technology types, and which were the focus of the measurement campaign, are known as rotary, diaphragm, and turbine gas meters. Rotary and diaphragm gas meters were found to leak at similar rates, and turbine gas meters were found to leak at a rate 3.8–3.9 times higher than rotary and diaphragm gas meters. In the sampling, turbine meters were more common in some regions; for example, in the Southeast, 15 of 20 (75%) gas meters measured for leakage were turbine meters, whereas in other regions, the gas meters measured for leakage had a much smaller share of turbine meters (ranging from 14% turbine gas meters in the Rocky region to 18% turbine gas meters in the Northeast region).

Nonetheless, the differences in the percentage of gas meters measured that were turbine gas meters can't fully explain the differences in the methane leakage rates per gas meter found in the study. As shown in Figure 11.2-1, the Southwest region had the highest leakage rate per meter, despite the measured sample having a much lower percentage (15%) of turbine gas meters than the Southeast region.

Because of the regional differences found, Moore 2019 recommended calculating emissions for each region separately, rather than using one nationwide emission factor, as the GHGI currently does. Moore 2019 also found significantly higher emissions from industrial meters than commercial meters, and thus recommended calculating emissions from industrial and commercial meters separately.

Figure 11.2-1. Commercial meter leakage measurement results. Values for EPA 1996 and GTI 2009 from EPA 2016b.



11.3. Commercial customer gas meter leakage in GIM

The Gas Index Model follows the recommendations in Moore 2019, applying values measured for leakage from commercial customer gas meters for each region, as detailed below.

Utilities vary widely in the mean size of commercial customers (that is, mean volume consumed per customer), and the distribution is highly skewed. The findings in Moore 2019 suggest that larger customers (industrial) have larger leakage per meter than smaller customers (commercial). Therefore, in calculating commercial meter leakage for individual utilities, applying the quantity leakage rates from Moore 2019 (kg CH_4 per year per meter) could be misleading, possibly underestimating emissions for utilities with larger-than-average commercial customers, and overestimating emissions for utilities with smaller-than-average commercial customers.

Rather than calculating leakage based on the *quantity* of methane leaked per gas meter (kg CH_4/gas meter/year) as reported in Moore 2019, instead GIM calculates *percentage* leakage rates for commercial meters in each region based on Moore 2019 data. For each region R, as defined in Moore 2019, the Gas Index Model calculates the percentage of gas that leaks from commercial meters, using the equations below. (Values are all annual, and only for the commercial sector.)

$$meter\ CH_4\ leakage\ volume_R = leakage\ per\ meter_R\ \times\ number\ of\ meters_R$$

$$leakage\ rate\ (\%)_R = \frac{meter\ CH_4\ leakage\ volume_R}{volume\ NG\ delivered_R \times\ CH_4\ fraction\ in\ NG}$$

Where:

- CH_4 leakage per meter: from Moore 2019, Table 20; units of kg CH_4/gas meter/year
- number of meters: assumed one meter per customer, following EPA 2016b; customer numbers from Form EIA-176 (EIA 2020b)
- volume natural gas (NG) delivered: from Form EIA-176 (EIA 2020b); uses total volumes, including direct sales volumes and transport volumes

- CH_4 fraction of NG (by volume): assumed 95%, since the volumes are consumer-grade gas (also known as dry gas)

Table 11.3-1. Percentage leakage rates for commercial gas meters. Leakage per meter for each region from Moore 2019, Table 20. Number of customers and gas volumes for 2018, from Form EIA-176 data (EIA 2020b).

Region	Comm. Customers	Leakage per meter (kg CH_4/y)	Total meter leakage (Gg CH_4/y)	Comm. volumes (Bcf)	Comm. volumes (Gg CH_4)	Comm. meter leakage (%)
Pacific	634,169	4.0	2.5	334	6,124	0.04%
Northeast	1,256,582	20.0	25	982	17,998	0.14%
Midwest	1,728,880	28.4	49	1,147	21,035	0.23%
Rocky	368,375	108.4	40	190	3,489	1.1%
Southeast	990,563	139.3	140	541	9,921	1.4%
Southwest	531,167	153.9	82	319	5,845	1.4%
Total	5,509,736		340	3,513	64,414	
Average		61				0.53%

We note that the percentage leakage for some regions (Pacific, Northeast, Midwest) are roughly similar to the nationwide averages used in GHGI 2020. However, for other regions (Rocky, Southeast, and Southwest) the leakage rates are an order of magnitude higher than the values used in GHGI 2020.

Moore 2019 speculated on the reasons for the regional differences: "the larger number of turbine meters sampled in the Southeast region could be a partial cause for the higher emission rates observed in that region. Another possibility could include different leak identification and repair procedures for finding and fixing industrial/commercial meter set leaks for different regions (and individual companies)."

11.4. Residential customer gas meter leakage

Another significant source of methane leakage is from meters for residential consumers, of which there were 69.7 million in 2018 (EIA 2020b). There have been three studies in North America measuring a large number of residential gas meters, which EPA has drawn on for its GHGI methodology (Table 11.4-1).

A 1996 study by GRI of U.S. residential meters found large variations in leakage rates between regions (EPA 1996b). Moore 2019 similarly found large variations between regions in commercial meter leakage, although the regions with highest residential meter leakage in the 1996 GRI study did not clearly correlate with the regions with the highest commercial meter leakage in Moore 2019. Therefore, there is not a clear pattern of higher leakage in certain regions across both types of meters.

Studies of residential meter leakage by GTI and Clearstone Engineering found lower leakage rates than the 1996 GRI study (EPA 2016b). We were not able to obtain those original reports to see if they provide additional data on regional differences.

Given these variations between U.S. regions, it is not clear how relevant the Clearstone Engineering study, conducted in Canada, is for leakage in the U.S.

Table 11.4-1. Studies of leakage from residential customer gas meters, and parameters adopted by EPA's GHGI.

	Number of meters	Area covered	Mean leakage rate (scf methane/ meter-yr)	Mean leakage rate (kg methane/ meter-yr)
EPA 1996	1,472	U.S.	143.27	2.8
Gas Technology Institute 2009	2,400	U.S.	48.99	0.9
Clearstone Engineering 2011	1,883	Canada	61.86	1.2
EPA 2016				1.5

Given that the past studies measured a large number of meters, they may have represented super-emitters well. Lacking recent data on a large number of measurements of residential meters in the U.S., we default to using the same methodology as in EPA's GHGI from 2016 onward (EPA 2016b).

EPA calculated leakage from residential meters by multiplying an emissions factor for each meter by the number of meters that leak. To estimate the number of residential meters, EPA used data on the number of residential customers and assumed one meter per customer. EPA then subtracted the estimated number of meters that are indoors, within residential buildings (EPA 2016b). The rationale for excluding indoor meters was that EPA "assumed indoor meter emissions were negligible because leaks within the confined space of a residence are readily identified and repaired" (EPA 2016b). The share of residential meters indoors was estimated to range from 61% in the Middle Atlantic region to 0% for other regions (South Central and Mountain).

Each indoor meter is assumed to leak 1.5 kg CH_4 per year per gas meter; that value for the leakage per gas meter is roughly the average of the values from the three studies shown in Table 11.4-1, all of which EPA cited as informing the value they adopted.

GIM applies this same approach to calculating residential meter leakage. EPA states the percentage of meters indoors in each region, but does not define which states are in each region. It appears that the regions used correspond to U.S. Census Divisions,[9] so GIM uses those divisions to assign a percentage of meters that are outdoors to each state. Then GIM calculates the number of residential meters that are outdoors, and the rate of methane leakage from those meters.

GIM does not adjust the methane leakage rate per meter to apply to different utilities depending on the rate of consumption of residential consumers. This means that in GIM estimates, utilities that have residential consumers that consume low levels of gas would have a higher percentage of leakage from their meters than in utilities that have residential consumers that consume high levels of gas.

This may be realistic, because gas lines remain pressurized regardless of whether they're being used heavily throughout the year (e.g., in a region with cold winters and extensive use of gas for space heating), or whether they're used lightly throughout the year (e.g., in a temperate region and/or a region that does not use much gas for space heating). More discussion of the relative lack of seasonal variation in methane emissions from the natural gas system, and the mechanisms that may be behind that, are in McKain 2015 and Sargent 2020.

[9] See, for example, https://www.ncdc.noaa.gov/monitoring-references/maps/us-census-divisions.php

We note also that, across the natural gas system, more recent measurements based on extensive surveys that explicitly tried to represent super-emitters have often found higher emissions than earlier studies. So it may be that older studies of residential meter leakage shown in Table 12-4.1, and used by the EPA for GHGI calculations, are underestimates.

The Gas Technology Institute has stated that they are conducting a study of residential meters in the U.S., but as far as we are aware it has not been published yet (GTI 2020).

11.5. Industrial sector customer gas meter leakage

GIM calculates leakage from customer gas meters for the industrial sector based on regional leakage rates reported in Moore 2019, following the same approach as for commercial customer gas meters (Section 11.3 above). Industrial gas meter leakage calculations are shown in Table 11.5-1. Industrial total volume of gas and industrial total customers are reported by gas companies to EIA on Form EIA-176 (EIA 2020b); values here are for both sales volumes and transported gas volumes. Leakage per gas meter (kg CH_4/gas meter/y) are from Moore 2019, Table 20. Gas companies report to EIA both direct sales from transmission lines and sales that pass through local distribution systems, without distinguishing between the two.

Given the inputs described above, GIM calculates the industrial gas meter leakage in each region (Gg CH_4/year), and then calculates the percentage leakage of gas flowing through the industrial customer gas meters, assuming that the consumer-grade gas is 95% CH_4.

Table 11.5-1 Industrial customer gas meter leakage.

Region	Industrial Total Volume (Bcf)	Industrial Total Customers	Leakage per gas meter (kg CH_4/ gas meter/y)	Industrial gas meter leakage total (Gg CH_4/y)	Leakage % of gas delivered
Midwest	2,094	68776	52.3	3.60	0.009%
Northeast	547	34802	172.5	6.00	0.060%
Pacific	898	40632	17.4	0.71	0.004%
Rocky	275	10571	322.5	3.41	0.068%
Southeast	2,491	19474	291.7	5.68	0.012%
Southwest	2,067	10675	372.9	3.98	0.011%

The leakage percentages for each region, as shown in Table 11.5, are then applied to all gas deliveries to industrial customers in the corresponding region.

11.6. Electric sector customer gas meter leakage

For leakage from electric customer gas meters, we are not aware of any studies that have measured leakage from customer meters for this sector. Also, it is not clear whether electric sector customer gas meters are included in EPA's GHGI, so there is not a clear methodology from the EPA to use as a default.

Therefore, GIM applies the percentage leakage rates for industrial customer meters, for each region, to electric customer gas meters. That is, for the Northeast region, GIM calculates that industrial customer

gas meters leak 0.06% of the gas passing through them; for electric sector gas customer meters in the Northeast region, GIM likewise applies the leakage rate of 0.06% of gas passing through the meters.

Gas deliveries to electric sector customers are reported by gas companies to EIA on Form EIA-176 (EIA 2020b); values used are for both sales volumes and transported gas volumes. Gas companies report to EIA both direct sales from transmission lines and sales that pass through local distribution systems, without distinguishing between the two.

12. Behind-the-meter leakage

There can be additional gas leakage within buildings from their gas-burning appliances such as furnaces, water heaters, and stoves. This can be due to incomplete combustion by appliances, or leakage without any combustion during certain steps. EPA has acknowledged that this type of leakage occurs, but behind-the-meter leakage is not included in EPA's GHGI (EPA 2016b, EPA 2020, Saint-Vincent and Pekney 2019). In the most recent revision to distribution leakage estimates in the GHGI, which was in 2016, EPA noted that "Limited data are available on this emission source" (EPA 2016b).

Since that latest EPA GHGI revision, a several studies have found significant rates of behind-the-meter leakage in residential and commercial buildings. While the studies include a low number of measurements for each type of appliance, the studies found that leaks occur occasionally across most types of appliances, indicating that leakage is a widespread phenomenon (see Table 12-1).

Table 12-1. Behind-the-meter leakage from residential and commercial buildings.

Appliance types	Leakage rate	Number of measurements	Region	Source
All residential appliances (furnaces, water heaters, stoves)	0.5%	75 homes	California	Fischer 2018a, Fischer 2018b
All residential appliances (furnaces, water heaters, stoves)	0.04%*	72 homes	Boston, MA and Indianapolis, IN	Merrin and Francisco 2019
Water heaters, with storage tanks	0.39%	18 water heaters	San Francisco Bay Area	Lebel 2020
Water heaters, tankless	0.93%	17 water heaters	San Francisco Bay Area	Lebel 2020
Commercial gas appliances (including for space heating, water heating, and cooking) and indoor pipelines	0.24%†	429 appliances	California	Johnston 2020
Commercial kitchens (cooking appliances and indoor pipelines)	1.16%	179 appliances	California	Sweeney 2020

*Not used as an input to GIM; see discussion below.
†Value for the scenario with methane levels as measured, and pipelines measured accounting for 50% of pipe joins.

Most of the field studies of behind-the-meter leakage in the U.S. that we are aware of found were conducted in California, motivated in part by methane regulations in the state, with three of the studies funded by the California Energy Commission (Fischer 2018, Johnston 2020, Sweeney 2020). With further studies, it may be possible to see whether there are regional differences in behind-the-meter leakage rates.

Merrin & Francisco 2019—based on measurements of residential gas appliances in Indianapolis, IN, and Boston, MA—found significantly lower leakage rates than in other studies of residential behind-the-meter leakage (Fischer 2018, Lebel 2020). However, Merrin & Francisco 2019 only measured leakage while the appliances were in use. For measurements when water heaters were in use, Lebel 2020 found leakage rates similar to those in Merrin & Francisco 2019. Lebel 2020 also measured water heaters' leakage when not in use; the study found that the leakage while not in use dominates the total methane leakage.

Therefore, the Merrin & Francisco 2019 results may greatly underestimate overall leakage, and GIM does not draw on that study's results.

For leakage in the residential sector, GIM uses the leakage rate estimated in Fischer 2018a (and also reported in Fischer 2018b), which measured leakage from all appliances in homes. GIM uses the leakage rate estimated in Fischer 2018a, 0.5% of gas consumed, to apply to all residential gas consumption.

We note that in 2019, the California Air Resources Board (CARB) began including behind-the-meter for residential gas in its official greenhouse gas inventory, basing their calculations on the results in Fischer 2018a (CARB 2019).

Lebel 2020 also measured residential behind-the-meter leakage, specifically from water heaters. However, space heating is the dominant use of residential gas use, so water heater leakage would likely play a smaller role than leakage from space heating appliances such as furnaces. Nonetheless, the leakage rates measured in Lebel 2020 are consistent with the overall leakage measured in Fischer 2018a.

For commercial sector gas use, the most comprehensive measurements of behind-the-meter leakage are in Johnston 2020, therefore we adopt a leakage rate of 0.24% for the commercial sector on that basis. We note, though, that for commercial kitchens, measured in Sweeney 2020, the leakage rate was nearly 5 times higher (1.16%).

With more extensive measurements of a variety of commercial buildings, and in various regions of the U.S., a more complete picture of behind-the-meter leakage may become available. If more measurements of leakage within buildings, across more regions of the U.S., become available, then in the future more accurate and region-specific values can be applied to each utility.

We note that these studies found a large range of emissions rates between individual appliances, which appeared to be related to both the type of appliance and how well maintained the appliances were (Johnston 2020, Sweeney 2020). Leakage rates for individual appliances were up to 10.6% (Johnston 2020), showing that individual appliances may suffer from significant leakage that goes unrepaired over some period of time, and therefore is found in a random sample in methane measurement campaigns such as Johnston 2020 and Sweeney 2020. The wide distribution of leakage showed that some appliances were relative super-emitters; in the study of commercial cooking appliances, for example, "the top 3 percent of leakers accounted for more than 50 percent of the total fugitive methane emissions" (Sweeney 2020).

13. Assigning LDC leakage by urban area

Although some LDCs serve only particular urban areas, in general there is not a one-to-one correspondence between LDCs and urban areas. We are not aware of data that specifies how much gas is consumed in particular urban areas, nor what share of gas consumption is supplied by particular LDCs. Therefore, to estimate methane leakage from gas consumption in each urban area, it is necessary to estimate how much of the urban area's gas consumption is supplied by particular LDCs.

Although some LDCs serve only particular cities, in general there is not a one-to-one correspondence between LDCs and urban areas. GIM uses a spatial analysis to estimate how much gas each LDC supplies to each urban area, for the residential and commercial sectors. Then GIM calculates an overall methane leakage quantity for each urban area based on the gas delivered to the urban area. Finally, GIM calculates methane leakage rates based on the quantity of methane leaked and the quantity of methane delivered to the city for the relevant sector. For example, for a given city, the model calculates leakage rates for components of residential sector leakage, including distribution pipeline leakage, customer gas meter leakage, and behind-the-meter leakage, using parameters specific to the residential sector. See the sections below for more detail.

The sections below also describe the spatial analysis for estimating gas deliveries to each urban area by each LDC, and thereby estimating methane leakage to each urban area.

13.1. Urban areas served by one utility

GIM estimates leakage rates for each LDC for each component (distribution pipelines, customer gas meters, and behind-the-meter leakage), and assumes that this leakage rate applies across all residential-commercial consumers within the LDC's service territory. Therefore, in urban areas that are served by only one gas LDC, GIM assumes the LDC's leakage rates by component apply to that urban area. Those components, discussed above, are distribution mains (Section 8), distribution service lines (Section 9), customer gas meters (Section 10), and behind-the-meter leakage (Section 11).

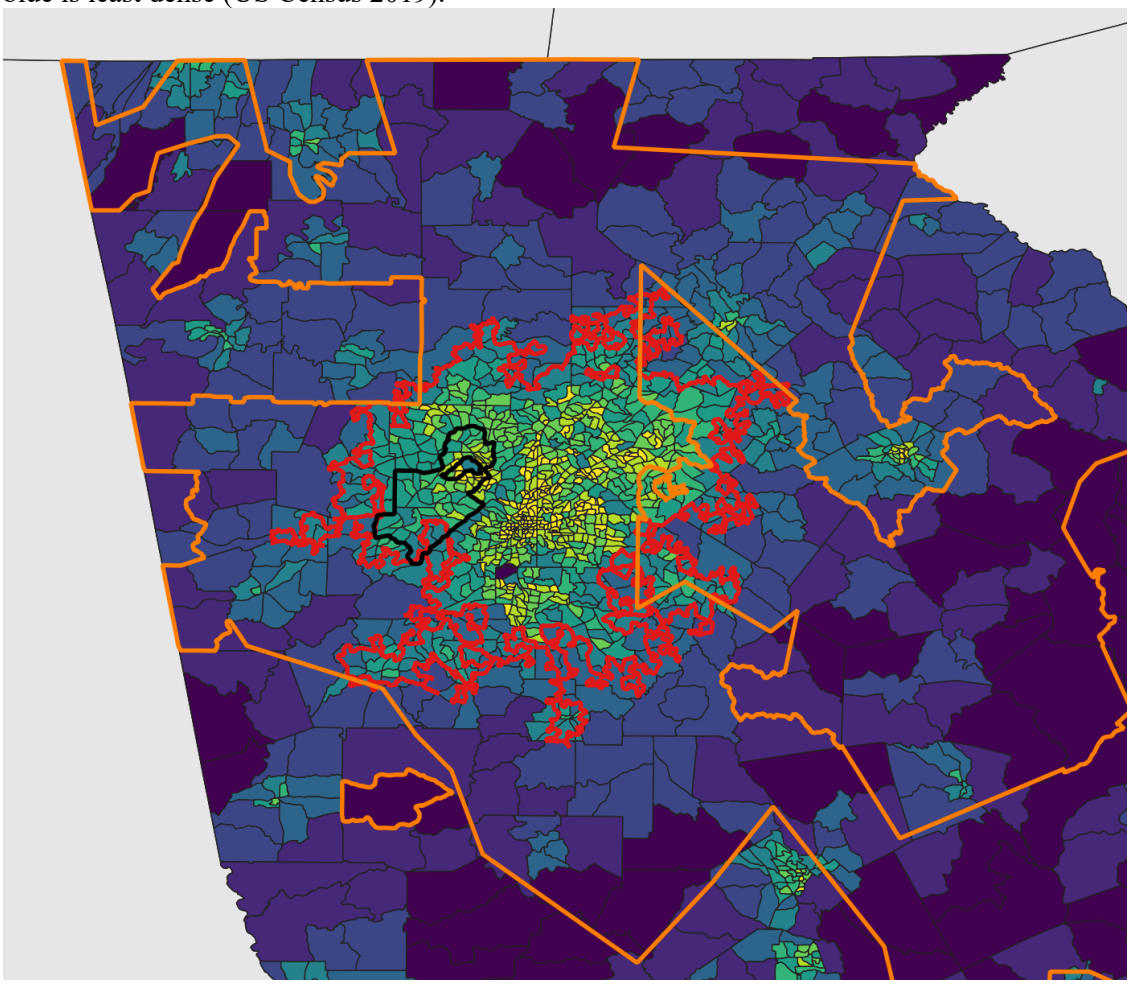
Some LDCs serve a much wider territory than a single urban area. However, in reporting to PHMSA on the properties of their distribution pipelines, LDCs do not specify the properties of the portion of the distribution pipeline system that is within each urban area, nor do LDCs specify the properties of the distribution pipeline system in urbanized areas compared with rural areas. GIM assumes that the leakage rate for an LDC's distribution pipeline system is the same across the whole territory that the utility serves. This is a limitation imposed by the way gas utility data is reported to PHMSA; if more granular data is made available on the distribution systems within particular urban areas, that could be used in the future to improve the accuracy of GIM estimates.

13.2. Urban areas served by more than one utility

For urban areas that are served by more than one utility, GIM estimates the quantity of methane leaked by each LDC for gas delivered to the residential and commercial sectors within the urban area, weighted by the estimated quantity of gas delivered to each metro area.

As an example, Figure 14.2-1 shows northern Georgia, with the Atlanta urban area outlined in red, the service territory of Atlanta Gas Light in orange, and the service territory of Austell Gas in black. (Sources of data are described in more detail below.) Austell Gas exclusively serves the area covered, and Atlanta Gas Light serves most of the rest of Atlanta. There is also a third gas utility that serves part of the eastern portion of the Atlanta urban area, Lawrenceville Utilities, not shown in the figure.

Figure 13-2.1 Map of Northern Georgia showing the Atlanta urban area, gas LDC service territories, and population density. The Atlanta urban area is outlined in red (U.S. Census 2018b). The service territory of Atlanta Gas Light is outlined in orange, and of Austell Gas is outlined in black (DHS 2019). The underlying layer is the population density for each census tract; yellow is most dense and dark blue is least dense (US Census 2019).



The steps below describe how GIM estimates the gas delivered to each urban area, and then the methane leakage allocated to each urban area.

$$Gas\ delivered_{ULS} = Population_{UL} \times \frac{Gas\ delivered_{LS}}{Population_{L}}$$

Where:

- Gas delivered$_{UL}$: Gas delivered to end residential/commercial consumers in urban area *U*, by LDC *L*
- Population$_{UL}$: Population within urban area *U* and within the service territory of LDC *L*
- Gas delivered$_{LS}$: Gas delivered to sector *S* (residential or commercial) by LDC *L* across its entire service territory
- Population$_{L}$: Population within the entire service territory of LDC *L*

Then GIM allocates methane quantities leaked to each urban area *U*, by each LDC *L*, due to each component *C*, by the following equation.

$$Methane\ leaked_{ULSC} = Gas\ delivered_{ULS} \times Methane\ leakage\ rate_{LSC}$$

Where:

- Methane leaked$_{ULSC}$: Quantity of methane leaked from gas consumed in urban area *U*, delivered by LDC *L*, to sector *S*, and due to component *C*. (The components are distribution mains, distribution service lines, customer gas meters, and behind-the-meter leakage.)
- Gas delivered$_{ULS}$: Quantity of gas delivered to urban area *U*, by LDC *L*, to sector *S*
- Methane leakage rate$_{LSC}$: Methane leakage rate (quantity of methane leaked per unit of gas delivered) for LDC *L*, delivering gas to sector *S*, and for component *C*

For each urban area, the total methane leakage within the city is the sum of across all LDCs, all sectors, and all components.

For example, to calculate methane leakage from commercial sector customer gas meters (a particular component, *C*) for a particular LDC (*L*), the gas delivered is the quantity for the relevant sector *S* (the commercial sector). The methane leakage rate for commercial customer gas meters is specific to that component *C*, so it is different from the methane leakage rate for customer gas meters in other sectors. Also, commercial customer gas meter leakage rates differ by region, so the leakage rate differs between LDCs. More details on the components and data sources are below.

13.2.1. Gas delivered by each LDC to each sector (Gas delivered$_{LS}$)

Each gas company reports annually to EIA on the quantity of gas delivered to end consumers in each sector—residential, commercial, industrial, electric, and vehicle fuels (EIA 2020g). All types of gas companies are required to report gas deliveries to other companies or end consumers, including companies that do not own any local distribution systems. In GIM, this sectoral gas delivery data for each LDC is used without modification. In GIM currently, the year of analysis is 2018.

GIM uses only volumes sold to residential and commercial consumers from companies that also report to PHMSA on their local distribution systems (PHMSA 2019). Data on volumes sold are from EIA. The EIA and PHMSA data sets do not share common IDs, and thus to link them we created a custom crosswalk file. For LDCs in a given state, the correspondence between the EIA and PHMSA data sets was usually straightforward based on LDC names and relative sizes (e.g., LDCs with larger distribution pipeline systems tended to have larger volumes sold). When names were ambiguous or there was more than one possible match, we researched the companies to find the correct link between the PHMSA and EIA data sets; the sources were primarily company websites and public utility commission documents.

GIM uses the "total volume" reported in EIA data for the volumes delivered to each sector, which is the sum of the "sales volume" and "transported volume." In EIA's definition, "sales customers" are those "consumers who buy their gas from the company that delivered it to them"; and "transported consumers" are those "consumers who buy their gas from a company other than the one that delivered it to them" (EIA 2020k). EIA also provides more detail on "transported gas," defining it as: "Natural gas physically delivered to a building by a local utility, but not purchased from that utility. A separate transaction is made to purchase the volume of gas, and the utility is paid for the use of its pipeline to deliver the gas. Also called 'Direct-Purchase Gas,' 'Spot Market Gas,' 'Spot Gas,' 'Gas for the Account of Others', and 'Self-Help Gas'" (EIA 2020h).

13.2.2. Population within each LDC's service territory (Population$_{L}$)

First, GIM identifies the service territory of each gas utility. The primary source of data for gas utility service territories is a data set created by Oak Ridge National Laboratory, which was released by the

Department of Homeland Security (DHS) on their Homeland Infrastructure Foundation-Level Data (HIFLD) platform (DHS 2019). The data set is stated to be current as of December 31, 2017. The current version, released in 2019, is an update of the initial version released in 2017.

We note that this DHS data set has been used by the EIA for spatial analysis of customers served by investor-owned utilities (EIA 2019), and by Argonne National Laboratory in its Energy Zone Mapping Tool (https://ezmt.anl.gov/data).

The DHS data set contained some internal inconsistencies and outdated information, so we took various steps to check and clean the data. Those steps are described in Appendix C.

To identify the population within each utility's service territory, GIM uses US Census data on population at the census tract level. Census tracts are divisions designed to contain approximately 4,000 people each, and the US Census estimates the population in each tract for years between each decadal census. GIM uses the American Community Survey (ACS) 5-Year Estimates for 2014–2018, published in 2019 (US Census 2019). Population counts for each census tract can be downloaded by state; values used were for "Total population," in table B01003. A shapefile for the boundaries of all U.S. census tracts is available from the U.S. Census as part of the TIGER-Line products (US Census 2018a).

GIM uses the Python library Geopandas (Jordahl 2019) for the following steps, processing one state at a time:

- Merge the population data tables and shapefiles for census tracts in the state.
- Calculate the area of each census tract in km^2. For area calculations, the shapefiles are converted to an equal area projection, EPSG 2163, the U.S. National Atlas Equal Area projection (https://epsg.io/2163), with units of meters.
- Calculate the population density of each census tract (area divided by population).
- Calculate the portion of each census tract's area that is within a given utility's service territory, using the Geopandas intersection function (https://geopandas.org/set_operations.html).
- Calculate the portion of population in each census tract that is within each LDC's service territory; this assumes that the population within each census tract is uniformly distributed.
- Sum the population across the census tracts (or portions thereof) to calculate the total population within the LDC's service territory.

We note that these counts of population within an LDC's service territory are not the same as counts of customers that each LDC reports to PHMSA. First, each LDC's reported number of "customers" in the residential sector actually reflect the number of connections to individual buildings or units, so one "customer" can be a household with more than one person. Second, not all people living within a utility's gas service territory are necessarily customers, because some buildings are not connected to gas supplies.

13.2.3. Population in a given LDC's territory and urban area ($Population_{UL}$)

To calculate the population served by each LDC within each city, GIM uses Geopandas to do two spatial intersections:

- Intersection of the LDC service territory and each urban area as defined by the US Census (US Census 2018b), to find the overlapping portions
- Intersection of the LDC service territory within each urban area (from the previous step) with census tract geospatial data on populations.

For each area isolated (for a particular LDC within a particular urban area, overlapping with a particular census tract), the steps for calculating the population follow the same steps described in section in 14.2.2.

13.2.4. Methane leakage weighted average for each urban area

Following the steps above, GIM then calculates the quantity of methane leaked$_{ULSC}$ (the quantity of methane leaked from gas consumed in urban area *U*, delivered by LDC *L*, to sector *S*, and due to component *C*).

To calculate the total leakage within each urban area, from gas delivered to the residential and commercial sectors, GIM sums the methane leakage quantities across all LDCs serving the urban area, and across sectors and components. Similarly, GIM calculates the total gas delivered to the urban area for the residential and commercial sectors, summing across LDCs. Finally, GIM calculates a methane leakage rate for the residential and commercial sectors by dividing the quantity of methane leaked by the estimated volume of gas delivered to these sectors within the urban area.

14. Urban area leakage measurements

A small number of U.S. urban areas—nine that we are aware of—have had peer-reviewed measurements of their methane emission rates. However, some of these studies have not estimated a leakage rate for natural gas used in the city (Plant 2019, Yadav 2019).

Many of these studies took additional steps to estimate the portion of the methane leakage attributable to natural gas used in the urban area. This attribution can be done through the use of inventories and/or measurements of other methane sources such as landfills, to exclude sources of methane other than natural gas, and then allocate the remaining emissions to the natural gas system. Alternatively, measurement of the ethane-methane ratio in the urban area can allow for estimation of the fraction of methane emissions that originate from fossil fuels—and therefore are attributed to natural gas delivered to the urban area.

Finally, some studies have estimated the natural gas consumed in the city in order to calculate a corresponding leakage rate for the natural gas system (percentage of natural gas delivered to the urban area that leaked). Table 14-1 shows results from all studies we are aware of that estimated a percentage leakage rate for natural gas delivered to a particular urban area or metro area. Table 14-1 also includes estimated leakage rates for Indianapolis, which has been covered by extensive methane leakage measurements, and where the authors have estimated gas deliveries to the city (although they did not calculate a percentage gas leakage rate).

Table 14-1. Measured methane emission rates for U.S. cities. Emissions rates in metric kilotons per year (kt/y). Emissions rate calculated relative to total gas consumption, as reported by the studies or that can be readily calculated from data in the studies. System boundaries are reported in the studies cited.

Urban area	Study	CH_4 emissions (kt/y)	CH_4 emissions from NG (kt/y)	% of CH_4 from NG	Leakage rate relative to total NG consumed
Boston, MA	McKain 2015	333	275	82%	2.7%
	Sargent 2020	n/a	n/a	n/a	2.5%
	GIM value				2.5%
Washington, DC-Baltimore, MD	Ren 2018	278	139	50%	0.7%†
San Francisco Bay Area, CA	Jeong 2017	228	39	17%	0.4%
Los Angeles, CA	Peischl 2013	411	192	47%	1.8%
	Wunch 2016	413	240	58%	1.6%
	GIM value				1.7%
Indianapolis, IN	Cambaliza 2015	68	46	67%	3.2%‡
	Lamb 2016 (aircraft)	41	21	52%	1.4%‡
	Lamb 2016 (towers)	81	42	52%	2.9%‡
	GIM value				2.5%

† Modified from the leakage rate stated in the study, 1.6%. For details, see Section 14.2, "Washington, DC-Baltimore methane leakage."
‡ Estimated based on the GIM estimates of natural gas delivered to the urban area, which are higher than the estimated gas deliveries in Lamb 2016, leading to a lower leakage rate than would be calculated from the gas deliveries reported in Lamb 2016. For discussion, see Section 14.5, "Indianapolis, IN, methane leakage."

For each of the urban areas shown in Table 14-1, GIM applies an estimated leakage rate based on the studies shown. If there is more than one study, employing different techniques, to estimate a leakage rate

for an urban area, then an average across studies is calculated as the value used in GIM. Details for each urban area are below on which studies were used, and how the GIM value was calculated.

For a given urban area, if the urban leakage rate calculated in GIM—based on distribution pipeline leakage, customer gas meter leakage, and behind-the-meter leakage—is lower than the value based on methane leakage measurements in the urban area, then GIM calculates additional leakage that is occurring in the city. It is not known which components may be contributing to this additional leakage; the additional leakage may be coming from distribution pipelines, customer gas meters, and/or behind-the-meter leakage.

For each of the urban areas shown in Table 14-1, Table 14-2 shows a comparison of GIM estimated leakage rates with the estimated leakage rates from the literature. For all the urban areas in Table 14-1 except for San Francisco, the leakage rates based on measurements were higher than the GIM estimate of urban leakage (based on distribution pipeline leakage, customer gas meter leakage, and behind-the-meter leakage), so there is additional urban leakage calculated. For the San Francisco urban area, the GIM estimated leakage rate is slightly lower than the value reported in the literature were similar, so GIM does not calculate any additional leakage for that urban area.

Table 14-2. Comparison of urban area leakage rates based on measurements in the literature and GIM estimated leakage rates. Percentage leakage rates in the literature are converted into units of g CH_4/Mcf assuming consumer-grade natural gas has a methane content of 95%, and a standard density of methane of 19.3 kg/Mcf.

Urban area	Leakage rate relative to total NG consumed (%)	Leakage rate relative to total NG consumed (g CH_4/Mcf)	GIM estimated urban leakage rate (g CH_4/Mcf)	Additional leakage based on measurements (g CH_4/Mcf)
Boston, MA	2.5%	458	118	340
Washington, DC	1.1%	202	138	63
Baltimore, MD	1.1%	202	138	63
San Francisco, CA	0.4%	73	75	0
Los Angeles, CA	1.7%	312	103	208
Indianapolis, IN	2.5%	458	96	362

All of the leakage rates reported in Section 14—whether expressed as percentage leakage, or as g CH_4/Mcf—are relative to the total estimated quantity of natural gas delivered to the urban area, for all sectors.

Below are details on the studies for particular cities.

14.1. Boston, MA, area methane leakage

As far as we are aware, the most comprehensive study of urban methane leakage that estimated a leakage rate for natural gas use in the city is McKain 2015, for the Boston metro area, which estimated a natural gas leakage rate of 2.7% (relative to total gas used by all sectors). These measurements were taken using towers in and around the Boston area, with continual measurements over the course of a year. Natural gas use within the study area was estimated using detailed modeling of gas-consuming infrastructure, in particular buildings (residential and commercial) as well as power plants.

Follow-on research using the same approach has been released (Sargent 2020), estimating natural gas leakage rate of 2.5% over the period 2012-2019, similar to the rate in McKain 2015. Because Sargent 2020 is based on continuous monitoring over a long period of time, with more recent measurements than

McKain 2015, GIM uses Sargent 2020 results. Sargent 2020 did not find a clear trend over time, therefore GIM uses the average leakage rate over the study period (2012-2019).

14.2. Washington, DC-Baltimore, MD, methane leakage

Ren 2018 stated a leakage rate of 1.6% for the Washington, DC-Baltimore metro area, based on urban area methane emissions rate of 8.9 kg/s (280 Gg/y) and an estimate that 50% of the methane emissions originated from natural gas.

However, it appears there is an error in this paper in the calculation of the quantity of natural gas consumed in the study area, in which gas consumption data for West Virginia was used instead of gas consumption data for Virginia. Ren 2018 reported (in the supplemental information Table S5) the values used for estimating the natural gas delivered to the urban area. The values reported there, and the values currently reported by EIA, are shown below in Table 14.2-1. EIA makes small revisions to data over time as states refine the data they report, so the values EIA reports now may be slightly different than what the EIA reported at the time that Ren 2018 was being written. Nonetheless, it appears that Ren 2018 used values for West Virginia rather than for Virginia. In EIA 2020, the values for Virginia are ~5-fold higher than the values for West Virginia.

Table 14.2-1. Comparison of gas consumption as reported in Ren 2018 against values reported by EIA (EIA 2020m).

Time period	Ren 2018: Virginia MMcf	EIA 2020: West Virginia MMcf	EIA 2020: Virginia MMcf
Feb 2015	12,610	12,611	58,062
Feb 2016	10,036	10,025	53,844

Ren 2018 estimated the portion of the population of each state that was within the study areas as: 100% of DC population, 90% of Maryland population, and 41.7% of Virginia population. Then Ren 2018 estimated the portion of natural gas delivered to end consumers in each state that was within the study area based on the proportion of population stated in the previous sentence.

Table 14.2-2. Values for gas deliveries to the states of Virginia and Maryland as well as the District of Columbia, as well as estimated gas delivered to the Washington, DC-Baltimore urban area. Compares values reported in Ren 2018 against those from EIA 2020.

Time period	Ren 2018: total gas delivered VA + MD + DC (MMcf)	EIA 2020: total gas delivered VA + MD + DC (MMcf)	Ren 2018: gas delivered to study area (MMcf)	EIA 2020 & Ren 2018: gas delivered to study area (MMcf)
Feb 2015	51,780	97,232	41,100	60,025
Feb 2016	41,846	85,654	33,300	51,558

In their calculations for the leakage rate (leaked methane / natural gas delivered to the city), using the value for Virginia increases the denominator, and thus lowers the leakage rate. The corrected values for the gas deliveries to the Washington, DC-Baltimore urban area are ~1.5-fold higher than the original values in Ren 2018, and thus the leakage rate is correspondingly lower.

Ren 2018 reported: "These CH4 emission rates from the natural gas system represent 1.1 ± 0.6% of the natural gas delivered to all customers in the study area in February 2015 and 2.1 ± 1.0% in February 2016." The average across the two time periods is 1.6%.

Using the corrected values for gas delivered, as shown in Table 14.2-2, leads to corrected leakage rates of 1.0% and 1.2% for February 2015 and February 2016, respectively, with an average across the two time periods of 1.1%. We also note that using corrected values for gas delivered leads to much closer leakage rates for the two measurement periods.

14.3. San Francisco Bay Area, CA, methane leakage

Jeong 2017 reported a natural gas leakage rate of 0.4% for the San Francisco Bay Area, which included a wide area encompassing the cities of San Francisco, Oakland, and San Jose, as well as areas north of San Francisco including Marin and Sonoma counties, which include significant livestock. Methane emissions were measured by 6 towers throughout the area, with measurements taken September to December 2015. Methane emissions from livestock, landfills, petroleum refining, and road transportation were estimated separately, to be able to estimate the portion of methane emissions from the natural gas system.

The 0.4% leakage rate reported in Jeong 2017 is equivalent to a methane leakage rate of 73 g CH_4 per Mcf gas delivered to consumers (based on the standard density of methane of 19.3 kg/Mcf, and assuming that consumer-grade natural gas is 95% methane). Based on GIM estimated gas delivered to the San Francisco urban area in 2018 of 174 Bcf, this leakage rate would lead to total leakage from the natural gas distribution system in 2018 of 12.7 Gg CH4. (Here, the natural gas distribution system is considered to include all steps required to deliver gas to end uses, including distribution pipelines, customer gas meters, and behind-the meter components including appliances.)

For the San Francisco urban area, GIM estimated leakage from the natural gas distribution system (including leakage from distribution pipelines, customer gas meters, and behind-the meter components) in 2018 of 12.9 Gg CH_4. Since the 12.9 Gg CH_4 leakage quantity is approximately the same as the value calculated above based on Jeong 2017, then no additional leakage is calculated in GIM, and no adjustment is made to the GIM estimate prior to incorporating the leakage estimate from Jeong 2017.

14.4. Los Angeles, CA, methane leakage

Attributing methane leakage in the Los Angeles urban area to the distribution system (distribution pipelines, customer gas meters, and behind-the-meter leakage) is more difficult than for other cities shown in Table 14-1, because unlike the other cities in that table, Los Angeles has non-negligible oil and gas production within the urban area as well as natural geological seeps of oil and gas that can emit methane (Peischl 2013).

Two studies of methane emissions in the Los Angeles urban area estimated the portion that is due to oil and gas production, as well as other causes, to then estimate how much of the methane emissions were from leakage of the city's natural gas distribution system, including distribution pipelines, customer gas meters, and behind-the-meter leakage. Peischl 2013 estimated that in 2010, the leakage rate for the natural gas distribution system was 1.8%, and Wunch estimated for the period 2007-2015 a similar leakage rate of 1.6%, with little trend over time. For GIM, we average the results of these two studies and use a leakage rate of 1.7%, which is equivalent to 312 g CH_4/Mcf.

Also, Wennberg 2012 made a high-end estimate of methane leakage from the distribution system of 2.0%, which is consistent with Peischl 2013 and Wunch 2016.

14.5. Indianapolis, IN, methane leakage

Urban area methane leakage in Indianapolis, IN, has been closely monitored for several years, perhaps more closely than any other city in the U.S., as part of a National Institute of Standards and Technology (NIST) test-bed program called INFLUX (NIST 2017).

There have been several campaigns to measure methane emissions in Indianapolis using monitoring by towers and flights overhead. These studies have also estimated the portion of methane emissions that originated from natural gas, as opposed to other sources of methane emissions in the urban area such as landfills.

None of the studies of Indianapolis that we are aware of calculated a percentage leakage rate for natural gas. One study (Lamb 2016) reported in the supplemental information a value for gas delivered to the city, but no source was stated for this value. The value appears to be derived from Citizens Energy Group, which serves the core of the Indianapolis urban area, in Marion County, IN. However, the study area in Lamb 2016 was larger, encompassing the whole urban area.

GIM estimates that the total gas delivered to the Indianapolis urban area in 2018 was about 47 Bcf/y, of which 62 Bcf/y (72%) was delivered by Citizens Energy Group, and nearly all of the remaining (30 Bcf/y) was delivered by Indiana Gas Company. Much smaller quantities were delivered by two small utilities, Citizens Gas of Westfield (0.41 Bcf/y) and the Town of Pittsboro (0.01 Bcf/y).

For Indianapolis, three sets of methane emissions measurements were taken, reported in two different studies:

- Flights overhead in 2011 (Cambaliza 2015)
- Flights in 2008, 2009, 2011, 2014 (Lamb 2016)
- Tower measurements in 2012–2013 (Lamb 2016)

For 2018, GIM estimated that Citizens Energy Group delivered 97% of its gas to the Indianapolis urban area, and that Indiana Gas Company delivered 20% of its gas to the Indianapolis urban area. Gas delivered to the Indianapolis urban area for other years was estimated from EIA data (EIA 2020b) for each of the years in which measurements were taken, as reported above, assuming that each of the two major LDCs sold the same percentage of their gas to the Indianapolis urban area as they did in 2018.

Table 14.5-1. Summary of data from studies of methane leakage in Indianapolis, estimated natural gas (NG) delivered to the study area, and calculated leakage rate as a % of CH_4 delivered to the city that leaked.

Study	CH_4 emissions (Gg/y)	% of CH_4 emissions from NG	Gas Index estimated NG delivered to study area (Mcf/y)	Gas Index estimated CH_4 delivered to study area (Gg/y)	% of CH_4 delivered that leaked
Cambaliza 2015	68	67%	78,339,850	1,436	3.2%
Lamb 2016, flights	41	52%	85,858,694	1,574	1.4%
Lamb 2016, towers	81	52%	80,372,142	1,474	2.9%
Average across studies					2.5%

Balashov 2020 has a useful discussion of the studies above, and also includes a reanalysis of data from Lamb 2016 restricted to only Marion County (which is also the territory served by Citizens Energy Group). Using the methane emissions rate from this reanalysis (53 Gg CH4/year), assuming 52% of the methane emissions are from natural gas (from Lamb 2016), and given Citizens Energy Group gas deliveries of 43,376,086 Mcf in 2018, we calculate a leakage rate of 3.5%. However, we do not include this estimated leakage rate as an input to GIM because the focus in GIM is on the whole urban area; because it is a reanalysis of data that is already included as an input to GIM; and because the assumption that 52% of the methane is from natural gas might be inaccurate when applying an estimate for the whole urban area to only the urban core in Marion County.

15. Building electrification

GIM estimates the change in emissions that would result from switching buildings from gas heating to electric heating, factoring in the life cycle emissions of both gas and electricity in particular locales.

For gas heating in a particular city, the CO_2 emissions from burning consumer-grade natural gas are calculated using a standard emissions factor from the EIA, 53.07 kg CO_2/MMBtu (https://www.eia.gov/environment/emissions/co2_vol_mass.php).

Life cycle methane leakage from the gas supply for each city is from the main results of the Gas Index, including leakage from production areas, transmission, distribution pipelines, and customer gas meters.

Gas heaters in southern states are assumed to have an Annual Fuel Utilization Efficiency (AFUE) of 90%, and in northern states 95%, based on EPA Energy Star ratings for efficient heaters; the EPA lists the states that are in each region (EPA 2020e). This follows the method in a recent analysis by the Rocky Mountain Institute, or RMI (McKenna 2020).

For electric heating in a particular city, the Gas Index considers two different cases for electric heater technologies: traditional electric furnaces and electric heat pump. For estimating the emissions resulting from installing each type of electric heater, we use a projection of how clean the electricity will be over the lifetime of the heater, estimated to be 15 years. The two technologies and two electricity projections lead to four scenarios, as shown below:

Traditional electric furnace & Business-as-usual electricity scenario	Electric heat pump & Business-as-usual electricity scenario
Traditional electric furnace & Cleaner electricity scenario	Electric heat pump & Cleaner electricity scenario

15.1. Scenario details

15.1.1. Traditional electric furnaces

Traditional electric furnaces use resistance heating, in which electric current passes through a material and generates heat due to resistance in the material These furnaces are 100% efficient—that is, 100% of the electricity is turned into heat (DOE 2020). Thus, for traditional electric furnaces, there is no different in their performance between different cities.

15.1.2. Electric heat pumps

Electric heat pumps are systems that can move heat into or out of a building from the outside, to cool or heat the building as needed. They can be highly efficient, delivering more heat than the electricity used to power them; how effective they are is measured by a metric called the Coefficient of Performance (COP). The COP for an electric heat pump depends on the climate, and at extremely low temperatures they must be supplemented with additional heating (e.g., from a traditional electric furnace using resistance heating). For each state, GIM uses the COP for electric heat pumps estimated by the RMI in a recent assessment of building electrification, which varies from a low of 2.1 in North Dakota to a high of 4.1 in California (McKenna 2020).

15.1.3. Business-as-usual electricity scenario

The business-as-usual projection for the electricity sector is from a model by the National Renewable Energy Laboratory (NREL), called the Regional Energy Deployment System, or ReEDS (Brown 2020). From the ReEDS 2019 Standard Scenarios, we chose the scenario called "Low natural gas prices and Low RE cost," to represent a case in which natural gas prices remain low and renewable energy costs continue to fall. This is the same scenario used in RMI's recent building electrification analysis (McKenna 2020).

ReEDS results that are readily available from NREL are for emissions from electricity generated in each state (Cole 2019). However, the electricity consumed in each state is not necessarily generated in that state; some states are net importers of electricity and others are net exporters of electricity. ReEDS results for emissions from electricity consumed in each state are not readily available.

GIM groups some states into larger interstate electric power markets, approximately following the RMI's analysis of building electrification (McKenna 2020). The categorization of states is shown in Table 15-1; we note that not all states are grouped into an interstate market. Based on this mapping, for each electricity market, GIM calculates the total electricity emissions of CO_2 and total electricity generated, then calculates a CO2 emissions rate for each market. GIM then calculates the average emissions rate over the period 2021-2035, to represent emissions over the 15-year lifetime of a new electric heater installed in 2021, as shown in Table 15-1. Similarly, for each state or interstate electricity market, GIM calculates the average share of electricity generated by natural gas over the period 2021-2035, also shown in Table 15-1.

The interstate electricity markets and the states they contain are as follows:

- ISO NE: Connecticut, Massachusetts, Maine, New Hampshire, Rhode Island, Vermont
- MISO: Arkansas, Iowa, Illinois, Indiana, Louisiana, Michigan, Minnesota, Missouri, Mississippi, North Dakota, Wisconsin
- PJM: Delaware, District of Columbia, Maryland, New Jersey, Ohio, Pennsylvania, Virginia, West Virginia
- SPP: Kansas, Kentucky, Nebraska, Oklahoma, South Dakota

To calculate CH_4 leakage from gas used for electricity, GIM starts with the ReEDS results for electricity generated from natural gas (Cole 2019). GIM then calculates the average efficiency of natural gas power plants in each state, based on historical data reported by EIA for natural gas power plant generation and fuel consumption (EIA 2020l). GIM applies that efficiency rate to all natural gas generation in each state in the ReEDS scenario, to calculate the natural gas consumed for power. GIM then estimates the methane leakage due to that gas consumption, from all steps in the supply chain (leakage from production areas, transmission pipelines, customer gas meters, and any portion of distribution pipeline leakage, if some gas for the electric sector is sold by an LDC). Finally, GIM calculates the average leakage rate (g CH_4/kWh electricity) over the period 2021-2035.

To convert methane emissions into CO_2 equivalents, GIM uses a global warming potential (GWP) over 20 years of 84 from the IPCC Fifth Assessment Report (IPCC 2013). This is more conservative than the 20-year methane GWP of 96 based on Etminan 2016, which has been used in some studies, e.g., Alvarez 2018.

Although the use of a 20-year GWP leads to much higher CO_2-equivalent warming than use of the 100-year global warming potential of 28 from the IPCC Fifth Assessment Report, we believe that the 20-year global warming potential better represents the impact of methane emissions. In 2019, New York State adopted a 20-year global warming potential in its state greenhouse gas inventory (Howarth 2020), and California also uses a 20-year global warming potential for methane in its

Short-Lived Climate Pollutants program, which includes efforts to reduce methane emissions (CARB 2015).

Table 15-1. Business-as-usual electricity scenario emissions rates for states and interstate electricity markets. Because GIM models only the contiguous U.S., Alaska and Hawaii are not included.

State/ interstate electricity market	CO2 emissions rate (g CO2/kWh elec)	CO2 and CH4 emissions rate (CO2e/kWh elec)
AL	330	430
AZ	341	415
CA	119	221
CO	506	538
FL	295	464
GA	283	370
ID	198	339
ISO NE	141	194
MISO	456	529
MT	128	145
NC	316	361
NM	446	486
NV	284	506
NY	113	146
OR	123	210
PJM	352	409
SC	191	242
SPP	382	451
TN	304	349
TX	295	392
UT	664	769
WA	54	86
WY	843	846

15.1.4. Cleaner electricity scenario

Many U.S. states and cities have targets to achieve 100% clean electricity by a specified date, set either by legislation, executive order, or other frameworks. GIM model inputs for clean electricity commitments are drawn from:

- The American Council for an Energy-Efficient Economy's State and Local Policy Database (ACEEE 2020)
- Sierra Club's "Ready for 100" policy tracker (Sierra Club 2020)
- The Clean Air Task Force, State and Utility Decarbonization Commitments (CATF 2020)
- American Cities Climate Challenge, Local Government Renewables Action Tracker (ACCC 2020)

- World Resources Institute, "2019 Was a Watershed Year for Clean Energy Commitments from U.S. States and Utilities" (WRI 2019)
- National Conference of State Legislatures, State Renewable Portfolio Standards and Goals (NCSL 2020)

Appendix D lists the clean electricity commitments included in the model for each urban area in the Gas Index.

For a cleaner electricity scenario, we assume that all cities and states that have such targets or mandated requirements will remain on track, with a linear ramp-down of non-clean electricity between 2018 and the year specified for achieving 100% clean electricity. Some cities have targets for achieving 100% clean electricity sooner than the state they are in; for example, San Diego has set a target of 100% clean electricity by 2035, whereas the state of California has a mandated requirement of 100% clean electricity by 2045.

This scenario assumes that when the main city in an urban area sets a clean electricity target, the whole area will meet that target; for example, San Francisco has set a target of clean electricity by 2030, and for this scenario, GIM applies that target to the whole San Francisco urban area as defined by the U.S. Census, which also includes the city of Oakland.

For the cleaner electricity scenario, for any cities that have a 100% clean electricity target or mandate (at either the city or state level), then GIM calculates CO2 emissions from electricity by taking the 2018 CO_2 emissions rate from ReEDS (Cole 2019) and creates a projection for each city in which the emissions rate for electricity ramps it down linearly to reach zero in the year in which electricity is targeted or mandated to be 100% clean. GIM then calculates the average CO2 emissions rate (kg CO_2/kWh electricity) over the period 2021-2035 for the city. Some cities have targets for achieving clean electricity that are earlier than the statewide target; other cities have citywide targets while the state has no such target. In these scenarios, the modeling is intended to represent the portion of electricity that the city procures, in keeping with its target for clean electricity.

To calculate CH_4 leakage for the cleaner electricity scenario, GIM assumes that natural gas generation would ramp down linearly from the level it was at in each state in ReEDS in 2018, reaching zero in the year in which 100% clean electricity is achieved. GIM then calculates for this scenario the natural gas consumed and related methane leakage following the same steps as described above for the business-as-usual electricity scenario. This results in an average methane leakage rate for electricity (g CH_4 leaked/kWh electricity generated) over the 15-year period 2021-2035.

If a city or state has a commitment for clean electricity that is less than 100% by a certain date, that was compared against the business-as-usual scenario based on ReEDS. For example, the state of Maryland has a target of 50% renewable electricity by 2030 (ACEEE 2020); the business-as-usual case here comes very close to achieving this target, with 48% renewable electricity generated in state in 2030. Therefore, no additional measures are applied for Maryland, including Baltimore, MD.

If a city or state had a target of at least 80% carbon neutrality, that was interpreted for purposes of modeling the cleaner electricity scenario to involve 100% clean electricity, since the electricity sector has proven easier to decarbonize than other sectors. In such cases, details are stated for particular states and/or cities in Appendix D.

Appendix A: Production area methane leakage studies

For production area methane leakage, the Gas Index Model draws on top-down measurements of whole production areas, which capture methane emissions from all activities in the areas, including gas extraction, gathering, and processing, but also from other activities such as coal mines, landfills, and dairies. The studies used in the Gas Index Model (with one exception, explained below) estimated emissions specifically from the natural gas system by explicitly excluding emissions from other sources.

The descriptions below for each producing region describe the studies used in GIM, and also other studies of methane leakage in each region that we are aware of. For studies that were not used in GIM, the descriptions explain the rationales. Unless otherwise stated, methane leakage rates are mass-based, and are for mean leakage rates.

Appalachian region

The Appalachian region, as defined by the EIA's Drilling Productivity report, encompasses the Marcellus and Utica shale plays, as well as conventional production, in southwestern New York, across most of Pennsylvania, nearly all of West Virginia, and eastern Ohio.

Due to the large size of the Appalachian region, production primarily from two different formations (Marcellus and Utica shale plays), and the large share of U.S. gas production that it is responsible for, we analyze the Appalachian region in depth for assigning a leakage rate.

Appalachia: Northeastern Pennsylvania

For northeastern Pennsylvania, Barkley 2017 drew on measurements from flights over northeastern Pennsylvania in 2015, estimating a methane leakage rate for unconventional wells only of 0.36% (2σ confidence interval of 0.08–0.72%). The study excluded emissions from coal mines, landfills, and livestock to allocate methane emissions measured to natural gas and oil production. Although the study's reported leakage rate is only for unconventional wells, according to the Pennsylvania Department of Environmental Protection's data on production by well type, in northeast Pennsylvania, unconventional wells accounted for 99.9% of production in 2018. Even if assuming that conventional wells have a mean leakage rate of 15% (calculation based on Omara 2016), the leakage rate for all wells would remain 0.36% (when rounded to 2 significant digits).

The estimated leakage rate in Barkley 2017 is consistent with earlier measurements for northeastern Pennsylvania taken in 2013 and reported in Peischl 2015, which estimated the leakage rate to be 0.18–0.41%, a range that includes the mean leakage rate in Barkley 2017. In Table 3-1, we report the main leakage rate for Peischl 2015 as the middle of the range (0.30%).

For northeastern Pennsylvania, GIM uses the average of the leakage rates in Barkley 2017 (0.36%) and in Peischl (0.30%), which is 0.33%.

Appalachia: Southwestern Pennsylvania and northern West Virginia

For southwestern Pennsylvania and northern West Virginia, there have been two top-down studies based on flights over the area, Barkley 2019a and Ren 2019, both taking measurements in 2015–2016.

Barkley 2019a was based on flights over southwestern Pennsylvania; the study estimated a methane leakage rate for unconventional wells of 0.5 ± 0.3%. Out of the total methane emissions measured, the study allocated a portion of total methane emissions to natural gas production by excluding coal, landfills, livestock, downstream natural gas (distribution). The study also allocated methane from oil and gas wells

to conventional and unconventional wells by assuming that conventional wells in the area leaked at a rate of 11%, based on Omara 2016. We infer the production rates used in calculating the leakage rate by dividing the reported methane emissions rate (as kg CH4/sec) for each category by the reported methane leakage rate (% of methane); for unconventional, 8.0 kg CH4/sec divided by 0.5% yields a production rate of 1,600 kg CH4/sec; for conventional, 2.8 kg CH4/sec divided by 11% yields a production rate of 25 kg CH4/sec. Thus, the total production rate for the study area is inferred to be 1,625 kg CH4/sec. We sum the methane emissions (8.0 + 2.8 = 10.8 kg CH4/sec) and divide by the total production (1,625 kg CH4/sec); this yields a mean leakage rate for conventional and unconventional wells of 0.66%. We note that the 11% leakage rate from Omara 2016 for conventional wells is the median rate (for more detail on Omara 2016, see below); the mean rate in Omara 2016 we calculate to be 15%, which we argue would have been more appropriate to use. However, we believe the study's choice of the leakage rate for conventional wells would not affect the leakage quantity or leakage rate calculated across all wells (conventional and unconventional). Although the calculations described here do not depend on the methane fraction by volume used in Barkley 2019, we note that the study used a methane fraction by volume of 88% (Barkley, personal communication).

Ren 2019 was based on flights over southwest Pennsylvania and northern West Virginia in 2015–2016; the study estimated a methane leakage rate of 1.1%. (The range of results was expressed as: "individual best-estimate emission rates from the three flight experiments ranged from 0.78 to 1.5%, with overall limits of 0% and 3.5%.") Based on concurrent measurements of ethane levels, the study concluded that ~70% of the emitted methane likely originated from coalbeds. The study excluded methane emissions from coal mines based on reported emissions for underground mines and estimated emissions for surface mines. The study notes that the measured values were "broadly consistent" with values reported in Caulton 2014 for the same region, and lower than values reported in Swarthout 2015 for the southwest Marcellus. Ren 2019 notes that the higher leakage rate in southwest Pennsylvania and northern West Virginia is likely due to the following factors:

- Southwest Pennsylvania and northern West Virginia have many older, conventional wells, whereas in northeastern Pennsylvania the well count is dominated by newer, unconventional wells, and Omara 2016 found conventional wells had far higher leakage rates than unconventional wells
- Southwestern Pennsylvania gas is wetter (contains more non-methane hydrocarbons such as ethane), and so requires more processing, which may contribute to higher leakage rates overall, in particular at processing facilities that are distinct from well sites.

Appalachia: Ohio

We are not aware of any top-down methane leakage measurements over Ohio, part of the Appalachia production region; production in Ohio comes primarily from the Utica shale play.

Therefore, GIM applies the same leakage rate to Ohio as for southwestern Pennsylvania and northern West Virginia.

Appalachia: Weighted average leakage rate and comparison with other studies

GIM calculates a weighted average leakage rate for Appalachia in the following way:

- First, GIM calculates production in the base year in each of five sub-areas of Appalachia: northeastern Pennsylvania, southwestern Pennsylvania, other Pennsylvania, West Virginia, and Ohio. Values are calculated from well-level data from state agencies, including both conventional and unconventional wells (Pennsylvania Department of Environmental Protection 2020, West Virginia Department of Environmental Protection 2020, Ohio Department of Natural Resources 2020). For these counties, the sum of production from these well-level data sets agrees within 0.6% with the stated production rate from EIA (EIA 2020a).

- Second, GIM calculates the share of Appalachian region production from each of the sub-areas identified above, based on the counties within the Appalachia region defined by EIA (EIA 2020a):
    - Northeast Pennsylvania: 32.2% of production; from Bradford, Columbia, Lackawanna, Luzerne, Lycoming, Pike, Sullivan, Susquehanna, Tioga, Wayne, and Wyoming counties.
    - Southwest Pennsylvania: 24.8% of production; from Allegheny, Armstrong, Beaver, Butler, Cambria, Fayette, Greene, Indiana, Somerset, Washington, and Westmoreland counties.
    - Other Pennsylvania: 3.2% of production; from Bedford, Blair, Cameron, Centre, Clarion, Clearfield, Clinton, Cumberland, Elk, Forest, Franklin, Huntingdon, Jefferson, Lawrence, McKean, Mercer, Potter, Venango, and Warren counties.
    - West Virginia: 17.0% of production, from all West Virginia counties within the Appalachian region.
    - Ohio: 22.8% of production, from all Ohio counties within the Appalachia region.
- Third, GIM assigns a leakage rate to each portion of Appalachia:
    - Northeast Pennsylvania: 0.33% leakage rate. Based on Barkley 2017 and Peischl 2015.
    - Southwest Pennsylvania: 0.88% leakage rate. Without any a priori reason to favor the results of Barkley 2019 or Ren 2019, we calculate the average of the leakage rate for all wells in the two studies to be 0.88% (average of 0.66% and 1.1%).
    - Other Pennsylvania: 0.88% leakage rate. Assumed to be the same as southwest Pennsylvania. Production from the other counties within the Appalachia region are primarily in central and northwestern Pennsylvania, and include many conventional wells, therefore GIM assumes the leakage rate for southwest Pennsylvania is representative. The other Pennsylvania counties are responsible for only 3.2% of Appalachia production, so the choice of leakage rate for these has only a minor effect on the overall leakage rate.
    - West Virginia: 0.88% leakage rate. Uses same rate as southwest Pennsylvania, since production in the two sub-areas has developed in tandem, and so are likely to have similar leakage rates. Ren 2019 covered southwest Pennsylvania as well as northern West Virginia, but did not report leakage rates specific to each state. We are not aware of any methane leakage estimates for gas wells in West Virginia alone.
    - Ohio: 0.88% leakage rate. Uses same rate as southwest Pennsylvania. Utica shale wells produce at high rates, similar to Marcellus wells (Hughes 2019). Therefore, GIM assumes that leakage rates for Ohio are likely to be similar to the leakage rates measured for southwest Pennsylvania and northern West Virginia.

Thus, GIM estimates an average leakage rate for the Appalachian region of 0.7%, and for Pennsylvania, 0.6%. For comparison, ground-level methane leakage measurements at well sites in the region have focused mainly on unconventional wells, finding the following mean leakage rates:

- Omara 2016: Omara 2016 measured well sites in Pennsylvania and West Virginia, estimating median leakage rates of 11% for conventional wells and 0.13% for unconventional wells. However, the distributions are skewed, so the mean leakage rate is significantly higher than the median rate. Based on the data reported in the paper (Table 1, and the stated assumptions that gas produced from conventional wells is 81% methane and for unconventional 83.1% methane), we calculate the mean leakage rate for unconventional wells to be 0.6%, and for conventional wells to be 15%. The study estimated the overall leakage rate for active wells in Pennsylvania to be 1.0% (95% CI: 0.7 to 1.5%); for West Virginia to be 3.0% (95% CI: 2.2% to 4.1%); and for the Marcellus as a whole to be 1.4% (95% CI: 0.98 to 2.0%). However, we note that this study was based on a limited number of measurements (35 well sites).

- Omara 2018 drew on measurements in Omara 2016 and additional on-site measurements to estimate an overall leakage rate for Appalachia of 0.9%, for both conventional and unconventional wells.
- Caulton 2019 took a similar approach as Omara 2016 and Omara 2018, with ground measurements at production sites, but with far more extensive measurements, covering unconventional wells at 673 well sites in both southwestern and northeastern Pennsylvania, measured in 2015–2016. This study estimated a leakage rate for unconventional wells of 0.53% (with a 95% confidence interval of 0.45−0.64%). These measurements are consistent with, and bolster findings in Omara 2016, and with top-down measurements (Barkley 2017, Barkley 2019, Peischl 2015, Ren 2018).

The most extensive well-site measurements for the Appalachian region are from Caulton 2019, as described above, but that study only measured unconventional wells. Conventional wells would contribute additional emissions that may significantly raise the overall leakage rate for the Appalachian region.

To estimate the effect of conventional well leakage on the overall average leakage for the Appalachian region, calculate a leakage rate for the region by an alternative method using well-level data. Well-level data is available from state agencies (Pennsylvania Department of Environmental Protection 2020, West Virginia Department of Environmental Protection 2020, Ohio Department of Natural Resources 2020), which distinguish between conventional and unconventional wells. For unconventional wells, we assign a mean leakage rate of 0.53% from Caulton 2019, and for conventional wells a mean leakage rate of 15% calculated from Omara 2016 (details above).

In the Appalachia region, 91.9% of active wells in 2018 were conventional, but these were responsible for only 3.1% of the total production of 16,762 Bcf of natural gas. Based on the leakage rates above, conventional wells would leak 74.7 Bcf of natural gas, and unconventional wells would leak 86.1 Bcf of natural gas. With similar compositions of methane in gas from conventional and unconventional wells (Omara 2016), nearly half the methane leakage would come from unconventional wells, despite their small share of total production in the area. The overall leakage rate for the Appalachia region calculated by this alternative method is 0.96%.

The leakage rate calculated by this alternative method is comparable to the Appalachian leakage rate of 0.9% estimated in Omara 2018, based on ground-level measurements and the properties of wells in the region. Further, we note that the high share of Appalachian methane leakage from conventional wells agrees qualitatively with an estimate for Pennsylvania by the Environmental Defense Fund, in which methane emissions were estimated based on production rates, following an approach used in Alvarez 2018 and Omara 2018 (EDF 2020b). GIM's estimate for Pennsylvania leakage in 2018 from natural gas wells is 640,000 tons of methane, where EDF's estimate for 2017 is significantly higher, 1,140,000 tons (EDF 2020b).

We note that this leakage rates based on ground-level measurements at well sites are not strictly comparable to leakage measured from top-down studies. Ground-level measurements would generally not capture emissions from other equipment in production areas, such as gathering pipelines and gas processing plants, which contribute significantly to methane emissions in production areas (Alvarez 2018, EPA 2020a). If adding methane emissions from these additional sources to estimate total emissions for production areas, the alternative method would estimate an emissions rate higher than 0.96%.

However, the alternative method presented here depends strongly on the emissions rate from conventional wells, and their leakage rate is uncertain, as it is based on measurements from only 18 well sites (Omara

2016). Thus, the alternative method is only a rough approximate; nonetheless, the value is roughly similar to the leakage rate based on top-down estimates.

In reports collected by Pennsylvania's Department of Environmental Protection, methane emissions from oil and gas wells are much smaller than estimated by the studies cited here, averaging 22,100 tons per year for 2014–2018 (Ingraffea 2020). The state reporting has serious shortcomings such as large, unexplained variations in emissions from year to year, both for individual wells and whole categories of wells—e.g., for all conventional wells, and all wells owned by particular companies (Ingraffea 2020).

Additional studies of methane leakage in the Appalachian region, which GIM does not draw on, include:

- **Goetz 2015:** This study drew on ground-level measurements in 2012 in southwest and northeast Pennsylvania. However, it measured only five well sites, so it has been superseded by other studies with much more extensive measurements of the same type (Omara 2016, Omara 2018, Caulton 2019).
- **Swarthout 2015**: This study drew on ground-level air samples collected around Pittsburgh (southwestern Pennsylvania) to make a "first approximation of methane emissions" in the area. Given the study methodology, GIM does not draw on this study.
- **Yuan 2015:** The study is based on flights over the region in 2013. The results for methane emissions were reported to be "consistent with those by the mass balance method in Peischl et al. [2015]." However, the study did not estimate a methane leakage rate; given the results from Peischl 2015 and other studies, we excluded Yuan 2015 from the inputs to GIM.
- **Schneising 2020:** This study drew on satellite measurements in 2018–2019 to estimate a leakage rate of 1.2% for Pennsylvania. (This is expressed as an "energy loss rate" of 1.2%, compared with the total volume of oil and gas produced; but as noted in the study, production in Pennsylvania was 98% gas and only 2% oil, so the leakage rate relative to gas produced is not significantly different from the energy loss rate.) While the measurements in Schneising 2020 were more recent than the measurements in the Appalachian region that are used above, Schneising 2020 did not explicitly exclude emissions from sources other than natural gas prior to comparing methane emissions to the oil and gas extracted in the area. The Appalachia region has significant sources of methane emissions other than from the natural gas system; in particular, a large share of the methane emissions in Appalachia come from coal (Barkley 2017, Barkley 2019, Ren 2019). Thus Schneising 2020 may overestimate methane leakage from natural gas production areas, and its results are not used in GIM.

Permian region

For the Permian region, GIM uses the methane leakage estimate from Zhang 2020, based on satellite measurements from 2018–2019, and supplemented by on-the-ground measurements released by the Environmental Defense Fund (EDF 2019). The study removed methane sources other than from oil and gas, estimating methane emissions from oil and gas production of 2.7 Tg/year, 93% of the total methane emissions of 2.9 Tg/year in the region. The study estimated a natural gas leakage rate of 3.7 ± 0.7%.

Other studies of methane leakage in the Permian region, which GIM does not use as inputs, include:

- **EDF 2020a:** This study of leakage using measurements from planes, helicopters, on-the-ground sensors, and tower sensors. As of April 2020, the study estimated a leakage rate of 3.5%, similar to the results of Zhang 2020. Since the results have not been published as a peer-reviewed study, and because the estimated leakage rate is not significantly different from the result in Zhang 2020, GIM does not draw on the EDF estimate.
- **Schneising 2020:** This study used the same satellite data set as Zhang 2020, over the same period (2018–2019) to estimate an "energy loss rate" of 1.3%, by dividing methane leakage in the area by the energy content of oil and gas produced. The study stated that, on an energy basis,

production in the area during the study period was 64% oil and 36% gas. Dividing the energy loss rate by the percentage of produced energy from gas yields a leakage rate for natural gas of 3.7%. This is comparable to the leakage rates from Zhang 2020 and EDF 2020a. However, Schneising 2020 did not attempt to exclude methane from sources other than oil and gas production areas, e.g., from livestock or landfills. Therefore, GIM does not draw on Schneising 2020 for the Permian region.

Haynesville

For Haynesville, GIM draws on methane leakage rates estimates in two top-down studies.

Peischl 2015 used flights over the Haynesville region in 2013 to estimate a leakage rate between 1.0-2.1%. Since the mean value for methane emissions reported was 15±6 tons/h, we assume the mean leakage rate is in the middle of the range stated, and thus was 1.55%. Peischl 2018, based on flights over the area in 2015, estimated a leakage rate of 1.0% ± 0.5% (1σ confidence interval), as reported in Table 1 of that study. Both studies used a bottom-up emissions inventories to exclude sources of methane other than from oil and gas, such as from livestock and landfills.

The uncertainty ranges of Peischl 2015 and Peischl 2018 overlap, so there is not a clear trend in the leakage rate over time. Therefore, we average the mean leakage rates from the two studies (1.6% and 1.0%), to yield the 1.28% leakage rate used in GIM (rounded to 1.3% in Table 1).

Other studies that measured methane leakage in the region:

- **Yuan 2015:** The study is based on flights over the region in 2013. The results for methane emissions were reported to be "consistent with those by the mass balance method in Peischl et al. [2015]." However, the study did not estimate a methane leakage rate; given the other results from Peischl 2015 and Peischl 2018, we excluded this study from the inputs to GIM.
- **Cui 2019a:** Study based on measurements in 2013, so there were more recent measurements from 2015 available using a similar method, and likewise using flights of a NOAA P-3 (Peischl 2018). Also, Cui 2019a did not explicitly state a methane leakage rate, whereas Peischl 2018 did, avoiding issues of a mismatch between the boundaries for leakage and production values used to calculate the leakage rate. We estimate that Cui 2019a's methane emissions measurement is equivalent to a leakage rate of ~1.3%, which is the same as the average of leakage rates of Peischl 2015 and Peischl 2018.

Andarko region

GIM uses methane leakage data from Schneising 2020, which reported an "energy loss rate" of 3.9%, based on an estimated "production mix of about 70 % natural gas and 30 % oil." The energy loss rate is calculated as the energy content of methane, divided by the energy content of oil and gas produced in the area. To convert it to an equivalent leakage rate relative to total gas production, we divide the reported leakage rate of 3.9% by the fraction of energy from natural gas (70%), yielding a methane leakage rate of 5.7%, as shown in Table 1.

An important caveat is that Schneising 2020 did not explicitly exclude other potential sources of methane emissions in the area, such as from livestock and landfills. Nonetheless, the approach in this paper, which calculates an enhancement of methane emissions in the study area, compared with the surrounding area, would be able to isolate an increase in emissions in the study area. The study area as well as the surrounding area has extensive animal agriculture (livestock) with significant methane emissions (Barkley 2019b), and the method used in Schneising 2020 should suffice to estimate the methane enhancement due

to oil and gas above the background methane emissions from animal agriculture (Barkley personal communication).

We are not aware of other top-down studies reporting methane leakage specifically from the Anadarko region. Omara 2018 used bottom-up data from other basins to estimate methane leakage rate of 1.7% for leakage at extraction sites in the Anadarko region; however, this was not based on any measurements within the Anadarko region, and also it would not represent additional emissions from gathering and processing that would be captured in top-down measurements.

Schneising 2020 did not state the assume methane fraction in gross natural gas production used for their methane leakage estimate. GIM calculations assume a methane fraction of 81%, based on Littlefield 2019, which reported mass fractions, which we converted to volume fractions.

Eagle Ford region

For the Eagle Ford region, GIM draws on measurements reported in Peischl 2018, taken in flights over the region in 2015. The study drew on two different flights, one over the western portion of the production area, estimating a leakage rate of 2.0 ± 0.6 %, and another over the eastern portion, estimating a leakage rate of 3.2 ± 1.1%. Based on the reported gas production rates for each portion (2.7 and 2.0 Bcf/month, respectively), we calculate a weighted average leakage rate of 2.5%. (Zhang 2020, Table S1, reported the same weighted average leakage rate for the Eagle Ford region.) Peischl 2018 excluded sources of methane other than oil and gas production through use of a gridded version of the EPA GHGI.

Other studies of methane leakage in the Eagle Ford include:

- **Schneising 2014:** Based on satellite measurements for the periods 2006–2008 and 2009–2011, this study reported an energy loss rate of 9.1 ± 6.2 % (relative to the total energy content of oil and gas produced). Peischl 2018 argues: "the estimate by Schneising et al. (2014) implies an atmospheric emission of roughly 12 ± 8% of the natural gas produced"; this is significantly higher than Peischl 2018 and also Schneising 2020.
- **Schneising 2020:** Based on satellite measurements in 2018–2019, this study reported an "energy loss rate" of 1.4 ± 0.7 %, based on a production mix of "about 55 % oil and 45 % natural gas." Dividing the energy loss rate by the percentage of produced energy from gas yields a leakage rate for natural gas of 3.1%. The study also noted that estimating emissions for the Eagle Ford is a challenge for their satellite-based approach, because of the production region's long, extended shape and "proximity to significant offshore sources in the Gulf of Mexico." Schneising 2020 argues that the much lower leakage rate compared with Schneising 2014 "suggest[s] that the emissions have been reduced by improving the technological standards since the early phase of hydraulic fracturing."

Greater Green River region

For the Greater Green River region—primarily in Wyoming, but also stretching into Colorado—GIM draws on the leakage estimate in Omara 2018, which was apparently based on measurements from Brantley 2014 for the Pinedale region in the northwestern part of the basin, and Robertson 2017. Omara estimated a mean methane leakage rate of 0.88% for this area.

Because Omara 2018 leakage rates were only for well-site leakage, the values to not capture methane emissions from gathering and processing. As described above, in Alvarez 2018 estimates for U.S. total emissions, 30% of methane emissions from production areas is allocated to gathering and processing,

while 70% is allocated to well-site emissions. Therefore, we adjust the well-site leakage rate from Omara 2018 (0.88%), dividing it by 70% to yield an approximate production area leakage rate of 1.3%.

Offshore Gulf of Mexico

GIM draws on the estimated methane leakage rate in Negron 2020 of 2.9%, with a 95% confidence interval of 2.2%−3.8%. This is based on flights around offshore production platforms conducted in 2018.

Other studies of Gulf of Mexico leakage:

- Yacovitch 2020: This was based on shipboard measurements of offshore oil and gas facilities conducted in 2018. The study did not extrapolate from its measurements to estimate methane leakage for all offshore oil and gas operations in the Gulf of Mexico, so we were not able to use its results as an input to GIM. The study found higher emissions in shallow-water facilities, despite the higher throughput of deepwater facilities. Similarly, Negron 2020 found much higher percentage leakage rates in shallow water than deepwater facilities.

Barnett region

For the Barnett region, GIM uses a leakage rate of 1.5%, based on three studies, which included top-down measurements in 2013 and 2015.

Peischl 2018, based on measurements taken in 2015, estimated a leakage rate of 1.5% ± 1.0% (1σ confidence interval). Karion 2015 used a similar method as Peischl 2018, with aircraft flights around the production area, but the measurements in Karion 2015 were taken earlier, in 2013. Karion estimated a methane leakage rate of 1.5%. The measurements of methane were reported as 0.66 ± 0.11 Tg CH_4 per year, which is an uncertainty range of ±18%, so we calculate that the equivalent range of leakage rates is 1.2–1.8%.

Zavala-Araiza 2015a compared a bottom-up inventory with the top-down measurements from Karion 2015, and reconciled them, such that the bottom-up inventory estimated a leakage rate of 1.5%, the same as in Karion 2015 and Peischl 2018.

San Juan region

Smith 2017 drew on flights over the San Juan region in 2015 to estimate a methane emissions rate of 0.54 ± 0.20 Tg/year. The study searched for possible significant emissions from sources other than oil and gas production in the study area, and did not find any. We note that the gas production here is primarily coal bed methane.

State data for production rates at the time of the measurements (April 2015) for the three main counties (San Juan and Rio Arriba in New Mexico, and La Plata in Colorado), was 82.8 Bcf for the month. Omara 2018 states the methane fraction for San Juan to be 83% by volume; using this value, and a methane density of 19.3 kg/Mcf, the gas produced would contain 1.33 Tg of methane. With the leakage measured of 0.54 Tg/year, or 0.045 Tg/month, this is a leakage rate of 3.4%. The methane leakage quantities measured in Smith 2017 had an uncertainty range of ±18%, so the equivalent range of leakage rates would be 2.8–4.0%.

For comparison, Alvarez 2018 reported a leakage rate for San Juan of 3.0%, citing Smith 2017, although it was not clear how that methane leakage rate was calculated.

Kort 2014 used satellite measurements from the SCIAMACHY instrument over the period 2003-2009 to estimate emissions from this basin of 0.59 Tg CH4/yr [0.50–0.67; 2σ]. This is close to the rate in Smith 2017, thus supporting those findings.

Bakken region

For the Bakken region in North Dakota and Montana, GIM draws on results from two studies that measured methane emissions over the region, Peischl 2016 and Peischl 2018.

Peischl 2016 drew on flights over the Bakken production region in North Dakota in 2014 to estimate a natural gas loss rate of 6.3 ± 2.1%, reported in Table 2. We note that Alvarez 2018 stated in Table S2 that it used a Bakken leakage rate of 3.7% based on Peischl 2016. However, Peischl 2016 explicitly states a leakage rate of 6.3 ± 2.1%; we are not aware of a reason for this discrepancy.

Peischl 2018 drew on flights over the Bakken in 2015 to estimate a methane leakage rate of 5.4% ± 2.0% (1σ confidence interval), based on flights over the region in 2015. Peischl 2018 excluded sources of methane other than oil and gas production through use of a gridded version of the EPA GHGI.

Because the uncertainty ranges of Peischl 2016 and Peischl 2018 overlap, there is not a clear trend in the leakage rate over time. Therefore, we average the two reported leakage rates (6.3% and 5.4%), to yield a leakage rate of 5.9%.

Other studies:

- **Schneising 2014:** Based on satellite measurements for the periods 2006–2008 and 2009–2011, this study reported an energy loss rate of 10.1% ± 7.3 % (relative to the total energy content of oil and gas produced). The study did not state the mix of oil vs. gas assumed in the calculations; if it was 25% gas, as used in the follow-up study Schneising 2020, then this would be equivalent to a gas leakage rate of ~40%. This finding was not corroborated by other measurements in later years; it is possible that the area had very high leakage rates during its early growth phase, which did not continue in later years.
- **Kort 2016:** This study took airborne measurements in 2014 of methane and ethane, but the study reported only details on ethane emissions and methane:ethane ratios, but did not estimate a methane leakage rate.
- **Gvakharia 2017:** This study drew on low-altitude flights in 2014 to measure methane leakage from individual well sites, and found substantial leakage from incomplete combustion at flares. This is important for understanding the mechanisms of methane emissions at extraction sites, however the study measured a relatively small number of sites (37), and did not estimate leakage for the whole production area, so it could not be used in GIM for estimating the Bakken's methane leakage rate.
- **Englander 2018:** This study drew on helicopter flights in 2014-2015, and combined with aerial measurements in 2015, to investigate how often extraction sites that were leaking at one time were still leaking at a later time. The findings are important for showing that leakage may often be due to persistent emissions from sites, including malfunctions that are not repaired. However the study did not include an estimate of methane leakage across the whole Bakken region, so it could not be used in GIM to estimate the Bakken's methane leakage rate.
- **Schneising 2020:** The study drew on satellite measurements in 2018-2019, estimating methane emissions in the region of 0.89 ± 0.56 million tons/year. The study calculated methane leakage as an "energy loss rate" of 1.3 ± 0.8 %, in which the energy content of the gas leaked was divided by the total energy content of oil and gas extracted in the area. Schneising 2020 assumed a production mix of 75% oil and 25% gas. Dividing the energy loss rate of 1.3% by the portion of gas in the energy portion (25%) yields a leakage rate for natural gas of 5.2%. The study notes that

this result is consistent with earlier results of Peischl 2016 (6.3%) and Peischl 2018 (5.4%). This study did not directly exclude other sources of methane in the study area, therefore we do not include it as an input to GIM. Schneising 2020 argues that the lower value in that study relative to Schneising 2014 suggests that leakage rates "can be improved by adopting new technologies and that the efforts to reduce fugitive methane emissions have been successful."

Fayetteville region

GIM uses a value of 1.3% based on Schwietzke 2017 and Vaughn 2018, based on a detailed measurements of emissions in this region in 2015, including measurements of diurnal variations in emissions related to the practice of liquids unloadings. The calculation of the leakage rate of 1.3% is explained below.

Schwietzke 2017 reported, when including manual liquid unloading events, the leakage rate for the west portion of the study area to be 1.7–2.0%, and for the east portion of the study area, they report a range of leakage rates 0.8–1.5%. We calculate the middle of the range for the west and east portions to be 1.85% and 1.15%, respectively. Given the reported production rate in each area (with the west producing twice as much as the east), the weighted average leakage rate is 1.6%.

Schwietzke 2017 reported, when excluding manual liquid unloading events, the leakage rate for the west portion of the study area to be 0.8–1.4%, and for the east portion of the study area, they report a range of leakage rates 0.5–1.2%. We calculate the middle of the range for the west and east portions to be 1.10% and 0.85%, respectively. Given the reported production rate in each area (with the west producing twice as much as the east), the weighted average leakage rate is 1.0%.

A companion study shows the diurnal variation in emissions allocated to liquids unloadings; the average emissions are approximately halfway between the value when liquids unloading emissions are at their peak and when they are at their lowest (Vaughn 2018). Therefore we adopt a leakage rate for Fayetteville that is midway between the two weighted averages from Schwietzke 2017, 1.6% and 1.0%, which is 1.3%.

This leakage rate is close to value used in Alvarez 2018, 1.4%, which is credited to Schwietzke 2017, although it is not clear from Alvarez 2018 exactly how that value was derived.

For other calculations in GIM for Fayetteville, we use the methane fraction by volume of 94% reported by Peischl 2015.

Other studies:

- **Peischl 2015:** For Fayetteville, Peischl 2015 estimated the leakage rate to be 1.0–2.8%, based on flights over the area in 2013. Alvarez 2018 cited this study in Table S2 as having a leakage rate of 1.9%, the midpoint of the range reported in the study. Because the measurements in Schwietzke 2017 and Vaughn 2018 were more recent and more detailed, GIM uses a leakage rate from those studies. We note this is a conservative approach, using a lower leakage rate than in Peischl 2015.

Denver-Julesburg region

For the Denver-Julesburg basin in Colorado and Wyoming, Peischl 2018 reported a leakage rate of 2.1 ± 0.9%, based on flights in 2015. Peischl 2018 excluded sources of methane other than oil and gas production, gathering, and processing through use of a gridded version of the EPA GHGI and state data; the other emissions were primarily from livestock.

Pétron 2014 drew on flights over Weld County, Colorado, in 2012, and excluded other sources of methane including livestock, landfills, coal mines, wastewater treatment facilities, and power plants, reporting a leakage rate of 4.1 ± 1.5 %. The study noted: "This number is close to the middle scenario (4%) reported by Pétron et al. [2012] for 2008 for the same region." We did not see that the methane fraction by volume assumed in the study was explicitly stated. But it is possible to infer the value used in the study, based on the stated natural gas production rate, the methane leakage rate attributed to oil and gas, and the standard density of methane (19.3 kg/Mcf), to calculate a methane fraction by volume of 73%.

Because the uncertainty ranges of Peischl 2018 and Pétron 2014 overlap, there is not a clear change over time in the leakage rate for this basin. Therefore, we average the two mean leakage rates (2.1% and 4.1%), to yield the leakage rate of 3.1% used in GIM.

Other studies:

- **Kille 2019:** Based on ground-level measurements in 2015, the study apportioned methane emissions between natural gas and other sources, including agriculture. The study allocated 63% of methane emissions in the area to natural gas. The study notes: "The attribution to NG agrees well with values reported in studies by Petron et al. (2014) for Weld County in May 2012 and Peischl et al. (2018) as shown in Table 1, where the dominating source of CH_4 is determined to be the NG sector." The study didn't quantify leakage for whole basin, nor estimate a leakage rate for natural gas wells.

Uintah Basin

For the Uintah Basin in Utah, GIM draws on two studies of methane leakage in the basin, Karion 2013 and Foster 2019, as described below.

Karion 2013 is based on flights in 2012 over the gas production area in Uintah County, reporting a methane leakage rate of 8.9 ± 2.7%. The study subtracted estimated emissions from livestock and natural seepage in the area, and noted that there was no coal bed methane production in the study area.

We note that Alvarez 2018 stated in Table S2 that the study used a leakage rate of 6.6% for the Uintah basin, based on Karion 2013. While the abstract of Karion 2013 states the leakage rate as "6.2%–11.7% (1σ)," the text also explicitly states a leakage rate of 8.9%, as noted above; we are not aware of the reason for use of the 6.6% leakage rate in Alvarez 2018.

Foster 2019 used ground-based observations in 2015–2016 together with an atmospheric model to estimate methane emissions during two wintertime "cold-air pool events" of 44.60 ± 9.66 and 61.82 ± 19.76 tons CH_4 per hour for the entire Uintah basin. The average of the two emissions rates, 53.21 tons CH_4 per hour, is similar to the Karion 2013 estimate of 54.6 ± 15.5 tons CH_4 per hour, but Karion 2013 only measured emissions from the gas field in Uintah County; the basin-wide gas production in 2015–2016 was 87% in Uintah County and 13% in Duchnese County (both of which were covered in Foster 2019).

Also, from 2012 (the year of measurement in Karion 2013) to 2015–2016 (the time of measurement in Foster 2019), basin-wide gas production decreased 21% and oil production increased 37%. Using the average production rate in 2015–2016 of 260.8 Bcf/year, and the assumption that gross gas production in the basin is 89% methane (Karion 2013) and the density of methane of 19.3 kg/Mcf, we estimate that the Foster 2019 emissions are equivalent to a basin-wide leakage rate for 2015–2016 of 10.4% .

The Foster 2019 measurements have uncertainty of ~30%, therefore there is not a clear trend over time in the emission rate. Averaging the leakage rates of Karion 2013 (8.9%) and Foster 2019 (10.4%) yields a leakage rate of 9.7%.

San Joaquin Valley

For estimating methane leakage from oil and gas operations in the San Joaquin Valley (SJV) in California, GIM draws on one recent study. Other, earlier studies of methane leakage from oil and gas production in California are also listed below.

Cui 2019b, which drew on measurements by tower and aircraft, estimated emissions for the period 2014–2016. Cui 2019b study estimated oil and gas production by excluding emissions from other sources; dairies were the largest source of methane emissions in SJV. Oil and gas operation emissions were estimated to be 220 ± 230 Gg/year.

Cui 2019b did not report a methane leakage rate, so we estimated a corresponding leakage rate by the following steps. The earliest data for California gas production data by county that was readily available was for 2017 (California Department of Conservation 2018). We were unable to access earlier editions of California's annual oil and gas production report, which are available only via FTP; the server refused connections. Therefore, we estimate SJV gas production for the period 2014–2016.

For 2017 data, we summed production in the counties Kern, Tulare, Kings, Fresno, Madera, Merced, Stanislaus, San Joaquin; 98% of this production was in Kern county, and surrounding counties have little gas production. For 2017, SJV gas production was 117 Bcf/year. The gas is 98% associated gas (produced along with oil), and SJV associated gas makes up 80% of California's total associated gas. For estimating SJV gas production in 2014–2016, we assume that SJV production tracked California state associated production over the period 2014–2017. Over 2014–2016, average California associated gas production was 147 Bcf/year, and in 2017 was 142 Bcf/year, or ~5% lower (California Department of Conservation 2019). We assume that SJV gas production was 5% higher on average over the period 2014–2016 than the 2017 rate of 117 Bcf/year; thus, SJV gas production in 2014–2016 is estimated to be 123 Bcf/y. Assuming produced gas was 91% methane (from Gentner 2014), and using the density of methane of 19.3 kg/Mcf, SJV gas production equates to 2,160 Gg per year of methane production. Dividing the methane leakage allocated to oil and gas of 220 Gg/year (Cui 2019b) by 2,160 Gg/year yields a leakage rate of 10%.

Other studies of SJV:

- **Cui 2017**: Drew on flights in 2010 to estimate SJV methane emissions from oil and gas production areas of 24 ± 11 Mg/h, which is 210 ± 96 Gg/year. (That median value is only slightly lower than the median value in Cui 2019b of 220 ± 230 Gg/year.) Cui 2017 study excluded methane emissions from livestock, which were estimated to be ~80% of total methane emissions in SJV. California's gas production has generally been declining, so SJV production was likely higher in 2010, and therefore the Cui 2017 results suggest that the leakage rate in 2010 was lower than in 2014–2016 as suggested by Cui 2019b.
- **Duren 2019:** This study by NASA researchers involved many flights over various types of facilities in California, including oil and gas production areas. The flights detected many emissions plumes, but the data was not used to estimate total methane emissions from oil and gas production activities, so it is not possible from the reported information to estimate a leakage rate for the areas covered.

- **Fischer 2017**: Leakage rate explicitly stated for California associated gas production: "The team estimated 5.3±1.1% (196 Gg / 3.69 Tg) of this associated gas production total is leaked during associated production and all processing and storage phases of the natural gas system." Based on top-down measurements, the study calculated a leakage rate for 2009. This is roughly similar to other studies above, however Fischer 2017 includes all associated gas production. Most associated gas is produced in SJV. However, because Fischer 2017 included additional production areas, and because the estimate is dated (for 2009), we do not use this study's result as an input to GIM.
- **Jeong 2013 and Jeong 2016**: Drew on tower measurements to model methane emissions statewide. The studies not report methane emissions from oil and gas production within the SJV, and therefore we were unable to use the results for this analysis.
- **Jeong 2014**: Drew on bottom-up inventories, adjusted to fit with top-down measurements in the Southern California Air District (SoCAB), to estimate oil and gas production area emissions of 128.2 Gg/year (with no uncertainty range stated). However, this study's estimates for SJV were not based directly on measurements there, so we do not include its results as an input to GIM.

Appendix B. State data on oil and gas production

Arkansas

Arkansas Oil and Gas Commission. Data available by county, for a given year.
http://www.aogc.state.ar.us/data/monthly.aspx.

- First select a year from the drop-down menu "Select Year"; then in the drop-down menu "Select Criteria," choose "County"; then in the drop-down menu for "Select Item," choose a particular county.
- The results will be displayed on the webpage; click on "Click to View Oil Spreadsheet" or "Click to View Gas Spreadsheet" to expand the window. On the left there are Monthly Totals.
- The table on the webpage can be copied from the table and pasted into a spreadsheet.
- Or the table can be downloaded by clicking on the Excel icon. However, the Excel files (xls) appear to be misformatted; for the files to be used subsequently, they may need to be re-saved (e.g., as xlsx or csv).

California

California Department of Conservation, Annual Reports of the State Supervisor of Oil and Gas. Data available by county, by year.
https://www.conservation.ca.gov/calgem/pubs_stats/annual_reports/Pages/annual_reports.aspx

- Under a given year's report, click on the link "Wells and Production by County," which will take you to another page with a form in which you enter your name and email.
- The website will then email you the data file.

Colorado

Colorado Oil and Gas Conservation Commission, Colorado Oil and Gas Information System (COGIS). Production available by county. https://cogcc.state.co.us/cogis/ProductionSearch.asp.

- In the first set of options, choose "County" (default is "Well). Then enter values for "Year Range." Then press the button "Submit."
- The results will be shown in a table on the webpage; this can be copied and pasted into a spreadsheet.

Louisiana

Louisiana Department of Natural Resources, Strategic Online Natural Resources Information System (SONRIS). https://www.sonris.com/.

- Click on "SONRIS Data Portal," then click on "Production Audit," which will expand the window to show many possible reports. Summary data by parish (Louisiana's equivalent of a county) can be downloaded. On the row for "Parish Production by Year," click on the table icon (according to the key in the right sidebar, this is the "Report" option). On the next page, enter the year to retrieve data for, and click "Submit Query."
- The webpage shows the results in a table, which can be copied and pasted into a spreadsheet.

Montana

Montana Board of Oil and Gas Conservation, Annual Production by County.
http://www.bogc.dnrc.mt.gov/WebApps/DataMiner/Production/ProdAnnualCounty.aspx.

- In the leftmost drop-down menu, choose "Year" (the default is "County"). In the other drop-down menu, choose "Equal To" and in the text box enter the year of data to retrieve. Then click "Search."
- The result will be shown on same webpage in a table, which can be copied and pasted into a spreadsheet.

New Mexico

New Mexico Oil Conservation Division (OCD). Data available by county. https://wwwapps.emnrd.state.nm.us/ocd/ocdpermitting//Reporting/Production/CountyProductionInjectionSummary.aspx.

- Data can be downloaded for one county at a time. In the first drop-down, choose the county of interest. In the second drop-down, "District," leave it as the default ("All"). In the third drop-down, choose a year, or leave as "All" to retrieve the full record starting in 1994. Click on "Get Report," and a new window will open. (If you have a pop-up window blocker, it may prevent this from opening.)
- Monthly data is shown for each year in a separate table. The data can be downloaded as an Excel file by clicking on the link "Excel" in the upper-left corner of the window.
- Opening the downloaded file in Excel may give a warning: "The file format and extension of 'CountyProductionInjectionSummaryReport.xls' don't match. The file could be corrupted or unsafe. Unless you trust its source, don't open it. Do you want to open it anyway?" Click yes to open it; for subsequent use of the file, save it as another format (xlsx or csv).
- Annual totals are not shown, but can be calculated from the monthly data.

North Dakota

North Dakota Department of Mineral Resources (DMR) publishes data for production of oil and gas production by county, with monthly values reported in pdfs. https://www.dmr.nd.gov/oilgas/stats/statisticsvw.asp

- Data can be extracted from pdfs using Tabula, an open source tool. https://tabula.technology
- Then annual totals can be calculated from the monthly reported data.

North Dakota allows operators to put new wells on "confidential" status, which can last their first year or more. The totals in the data sets above do not include production from confidential wells, so recent data from North Dakota may underestimate actual production. GIM uses 2018 as the analysis year for data accessed in 2020, which should lead to minimal underestimation.

Ohio

Ohio Department of Natural Resources. Data available for individual wells, by year. https://ohiodnr.gov/wps/portal/gov/odnr/discover-and-learn/safety-conservation/about-odnr/oil-gas/oil-gas-resources/production.

- For older data, individual well records can be downloaded for all wells as a single file. For the latest year with complete annual data, individual well data is available in two files, for "conventional only" and for "horizontal-only." Conventional well production is reported annually, whereas horizontal well data is reported quarterly.
- For horizontal wells, data can be summed across quarters to yield annual data.

Pennsylvania

Pennsylvania Department of Environmental Protection, Oil and Gas Reports. Data available for individual wells, by year.
https://www.dep.pa.gov/DataandTools/Reports/Oil%20and%20Gas%20reports/Pages/default.aspx

- Click on the link "Oil and Gas Production and Waste Reports." On the next page, click "Agree" to agree to the terms of service. On the next page, in the left sidebar, click "Production / Waste Reports." On the next page, click "Production Reports."
- In the drop-down menu "Reporting Period," choose a selection of well types (conventional or unconventional) and time span to return records for. Because there are a large number of wells, it may be preferable to download one file for all conventional wells (which report annually), and then for unconventional wells to separately select all the monthly production reports for a given year, and return those. After selecting the well types and time periods in this dropdown, click the button in the upper-right, "View Report." It may take some time, but the data will appear in the webpage as a table.
- To save the full data as a file, click on the disk icon (in the middle of the toolbar above the table); this gives options for saving the data as an Excel file, csv file, or other option.

Texas

Texas Railroad Commission, Production Data Query (PDQ) system. Data available by county, for specified period of time. http://webapps.rrc.texas.gov/PDQ

- Choose "General Production Query." On the next page, in the options for "Initial View," choose "County." In the next set of options, choose a date range (e.g., Jan 2018 to Dec 2018). In the options for "District," choose "Statewide." Other settings can be left as defaults. Press the button "Submit."
- Results are shown in a table on the webpage. Click the link "View All Results" to show the full data set.
- The table can be copied and pasted into a spreadsheet.

We note that Texas releases preliminary data for each month in pdfs, but this data is typically missing a significant portion of production due to newer wells that have not finalized reporting to the state. Over time as data is finalized for these wells, Texas updates its production data in PDQ; it typically takes 18 months for nearly all the data to be reported for a given month's production. EIA attempts to adjust for this slow reporting the values it states for Texas production, but EIA's values are necessarily approximate, and they can change over time (increasing or decreasing), as more data becomes available.

Utah

Utah Department of Natural Resources. Data available by county, by year.
https://oilgas.ogm.utah.gov/oilgasweb/live-data-search/lds-prod/prod-by-cnty-lu.xhtml

- In the box labeled "Year," in the drop-down menu that has the default value "LIKE," instead choose "EQUALS." Then enter the year of data to retrieve in the text box to the right. Below, click the button "Search."
- County-level annual sums will be displayed in a table on the webpage.
- To download the full data as a csv, click on the csv icon to the right of the text "All Pages" (this ensures downloading the full records, in case the query returned more results than are shown on the webpage).

West Virginia

West Virginia Department of Environmental Protection. Data available for individual wells, by year.
https://dep.wv.gov/oil-and-gas/databaseinfo/Pages/default.aspx

- Records for individual wells can be downloaded as a zip file for each year's data. Historical data is continually updated as lagging data is filed by operators.
- The latest year of data is typically listed with a link such as "2019 Production Data." Earlier years are listed under the heading "Historical Production Data Updates"; click on the link for each year (e.g., "2018") to download that year's data.
- For each fuel (gas, oil, NGLs) the table shows individual well production by month and also an annual total.
- Data can be grouped by county and summed to yield production by county.

Wyoming

Wyoming Oil and Gas Conservation Commission. Data available by individual well.
http://pipeline.wyo.gov/grouptrpMenu.cfm

- To the left of the text "Download All Counties Production by Selected Year," there is an icon of a cowboy on a horse; click on the icon to go to a page for the query.
- Make a choice in the drop-down menu "Select Year," then press the button "Submit." Data will download as an Excel (xls) file.
- Opening the downloaded file in Excel may give a warning: "The file format and extension of 'CountyProductionInjectionSummaryReport.xls' don't match. The file could be corrupted or unsafe. Unless you trust its source, don't open it. Do you want to open it anyway?" Click yes to open it; for subsequent use of the file, save it as another format (xlsx or csv).
- Data can be grouped by county and summed to yield production by county.

Appendix C. DHS Local Distribution Company data

The Department of Homeland Security data set Natural Gas Local Distribution Company Service Territories (DHS 2019) required steps to manipulate and clean the data to ensure data quality. This appendix describes the steps taken; all of these steps are performed by the model code, so no processing is required of the DHS data set prior to inputting into GIM.

The DHS data set includes, in the column "COMPID," ID numbers for each utility, and in the column "LDC_STATE" the state of operation of the utility. Combining the two creates an ID that matches the data in LDC reports to EIA (EIA 2020g). For example, for Atlanta Gas and Light EIA uses the ID 17600626GA. With these IDs, then the service territory shapefiles can be connected to other utility data from EIA.

DHS data includes gas deliveries, but the data does not appear to be for 2018; it may be for 2017. GIM uses gas deliveries reported by EIA for each LDC (EIA 2020g), rather than the gas deliveries data in the DHS data set. GIM connects the service territory boundaries in the DHS data set to gas delivery data from EIA via the EIA IDs.

Some problems with IDs were identified because the DHS data set used the same ID for two different LDCs, even though the IDs EIA issues are intended to be unique. Some problems were identified because there was no match in the DHS data set for an ID in the EIA data set; these were tracked down to typos in the IDs in the DHS data set, with missing digits or switched digits.

LDC name in DHS data set	**Incorrect or outdated ID**	**Correct or current ID**
WASHINGTON GAS LIGHT COMPANY	17616173VA	17671254VA
WASHINGTON GAS LIGHT COMPANY	17671254MD	17616172MD
NEW MEXICO GAS COMPANY	17617270NM	17673850NM
MOUNTAINEER GAS CO.	17616239WV	17673240WV
MIDAMERICAN ENERGY	17631004NE	17650920NE
INTERMOUNTAIN GAS CO	17606931ID	17606391ID
ATMOS ENERGY - LOUSIANA DIVISION	1760016LA	17672060LA
PIEDMONT NATURAL GAS	1769905NC	17699051NC
LIBERTY UTILITIES (ENERGYNORTH)	17604829NH	17675803NH
CENTREVILLE, TOWN OF	17600003MS	17602193MS
TISHOMINGO NATURAL GAS SYSTEM	17600003MS	17619898MS
LOBELVILLE, CITY OF	17600183TN	17608530TN
ST. LAWRENCE GAS	17614659NY	17611894NY
HALLOCK, CITY OF	17617865MN	17605402MN

In New York state, the DHS data set used the ID 17610204 for territories served by National Grid and its subsidiaries. These territories include Staten Island, Brooklyn, the remainder of Long Island, and upstate New York. In EIA's system (EIA 2020b), these territories are listed as three separate entities with separate IDs (17610204NY, 17601565NY, and 17617823NY). To allow for correspondence between the DHS data for territory boundaries and the EIA data set, GIM combines the three National Grid entities into a single entity; similarly, data from PHMSA for these three entities are combined into one.

For Washington Gas & Electric—which serves Washington, DC, and surrounding areas—there were errors in the DHS data set for territory boundaries. The company's territory listed for Maryland included portions in West Virginia and Virginia, whereas the company's territory listed for Virginia did not include

all of the portions in Virginia. In GIM, the portion in Virginia that was listed with Maryland is removed and transferred to be part of the portion listed for Virginia.

In Chicago, IL, the DHS data set shows the territory for NICOR Gas Company (17610322IL) encompasses the territory of Peoples Gas Light & Coke Co territory (17610960IL). Our understanding is that Peoples Gas has exclusive service in the territory it serves, and does not share customers with NICOR; therefore, the Peoples Gas territory was subtracted from the NICOR territory.

In Omaha, NE, the DHS data set shows the territory for Black Hills Energy territory (17631004NE) almost completely encompassing the territory of Municipal Utilities District of Omaha (17609407NE) Our understanding is that Municipal Utilities District of Omaha has exclusive service in the territory it serves, and does not share customers with Black Hills Energy; therefore, the Municipal Utilities District of Omaha territory was subtracted from the Black Hills Energy territory.

In Atlanta, GA, the DHS data set shows the territory for Atlanta Gas Light (17600626GA) almost completely encompassing the territory of Austell Nat Gas Sys (17600689GA). Our understanding is that Austell Gas has exclusive service in the territory it serves and does not share customers with Atlanta Gas; therefore, the Austell Gas territory was subtracted from the Atlanta Gas territory.

Lawrence, KS, is served by Black Hills Energy (17681028KS) according to the Kansas Public Utilities Commission (Kansas PUC 2014), the ACEEE State and Local Policy Database (ACEEE 2020). The DHS data set does not show Black Hills Energy serving Lawrence, but in GIM the city is counted as being served by Black Hills Energy.

Cedar Rapids, IA, is served by MidAmerican Energy (17650918IA), according to the company's service territory map (https://www.midamericanenergy.com/territory-communitylist, accessed November 30, 2020). The DHS data set does not show MidAmerican Energy serving Cedar Rapids, but in GIM the city is counted as being served by MidAmerican Energy.

Two transmission-only companies are excluded from the DHS data set, to avoid having population assigned to them and influencing the model results for gas deliveries per person. Those companies are Kinder Morgan (EIA ID 17617235NE, and known in EIA data as BLACK HILLS GAS DISTRIBUTION LLC) and TUSCARORA GAS TRANSMISSION CO (17695180CA).

Appendix D. Clean electricity commitments

Urban areas in the Gas Index are listed below if the urban area or state it is within have clean electricity commitments. If an urban area crosses state boundaries, then the main state that it is within is used as the basis for evaluating clean electricity commitments at the state level. If the major city within a given urban area has a clean electricity commitment, it is assumed that the whole urban area will follow the same commitment.

All statements in Appendix D regarding the approach in GIM are referring to the cleaner electricity scenario, unless otherwise specifically noted.

Alabama
We are not aware of clean electricity targets for the state of Alabama.

- **Montgomery, AL**: The city was not listed in ACEEE 2020, so it is modeled as not having any clean electricity targets.

Arkansas
We are not aware of clean electricity targets for the state of Arkansas.

- **Little Rock, AR**: According to ACEEE 2020, the city does not have any climate mitigation goal or renewable energy goal, so it is modeled as not having any clean electricity targets.

Arizona
In 2006 Arizona established a Renewable Portfolio Standard of 15% by 2025 (NCSL 2020). We are not aware of further state-level clean electricity commitments.

- **Phoenix, AZ**: According to ACEEE 2020, "The 2050 Sustainability Goals established goals to achieve carbon neutrality by 2060." For purposes of GIM's cleaner electricity scenario, we interpret this as a commitment to 100% clean electricity by 2060.

California
In 2018, California passed S.B. 100, requiring the state's electricity supply to be 100% clean by 2045. This is assumed to apply to each city in California, unless the city has adopted a more ambitious commitment.

- **San Francisco, CA**: Within the San Francisco urban area, as defined by U.S. Census, the cities of San Francisco and Berkeley both committed to 100% clean electricity by 2030 (Sierra Club 2020); this commitment of 100% clean electricity by 2030 is assumed to apply to the whole San Francisco urban area.
- **San Diego, CA**: The city has committed to 100% clean electricity by 2035 (Sierra Club 2020), which is assumed to apply to the whole San Diego urban area.

Colorado
Colorado passed legislation for 100% clean for large investor-owned utilities (IOUs) by 2050 (WRI 2019).

- **Denver, CO**: The city has made a more ambitious commitment for 100% clean electricity by 2030 (Sierra Club 2020), which is applied in GIM to the whole Denver urban area.

Connecticut
In 2019, Connecticut government Ned Lamont signed an executive order directing the state to reach 100% clean electricity by 2040 (WRI 2019, Morehouse 2019); this target is assumed to apply to each urban area in the state.

- **New Haven, CT**: According to ACEEE 2020, "Through the Climate and Sustainability Framework, New Haven established a goal to achieve carbon neutrality by 2050." The governor's executive order for 100% clean electricity by 2040 is an earlier timeline, so in GIM the New Haven urban area is modeled as achieving 100% clean electricity by 2040.
- **Hartford, CT**: According to ACEEE 2020, "Hartford's Energy Improvement District Board states its goal of reducing GHG emissions 45% below 2001 levels by 2030." The governor's executive order for 100% clean electricity by 2040 is a more ambitious goal, so in GIM the Hartford urban area is modeled as achieving 100% clean electricity by 2040.

District of Columbia
The Clean Energy D.C. Omnibus Act of 2018 committed the district to 100% clean, renewable electricity by 2032 (Sierra Club 2020). The DC urban area includes portions in Virginia, which has passed state legislation requiring 100% clean electricity by 2050 (Sierra Club 2020), and Maryland has passed state legislation requiring 50% clean electricity by 2030 (WRI 2019). Since the bulk of the DC urban area is within Virginia, in GIM the DC urban area is modeled as achieving 100% clean electricity by 2050.

Delaware
The Gas Index does not include any urban areas exclusively in Delaware. Wilmington, DE, is included as part of the Philadelphia, PA, urban area. See the section below for Pennsylvania for information on how the Philadelphia, PA, urban area is modeled in GIM.

Florida
We are not aware of clean electricity targets for the state of Florida.

- **Orlando, FL, urban area**: Committed to 100% clean electricity by 2050, which is assumed in GIM to apply to the whole Orlando urban area.
- **Tampa-St. Petersburg, FL urban area**: St. Petersburg, FL, has committed to 100% clean electricity by 2035, but it accounts for less than half the population of the Tampa-St. Petersburg urban area defined by the U.S. Census. Tampa has not set a clean electricity commitment that we are aware of. Therefore, in GIM, no clean electricity target is set for the whole Tampa-St. Petersburg urban area.
- **Miami, FL**: The city of South Miami, FL, has committed to 100% clean electricity by 2040, however it has a population of only ~11,000, a small fraction of the total population in the Miami urban area. Therefore, in GIM, no clean electricity target is set for the whole Miami urban area.

Georgia
We are not aware of clean electricity targets for the state of Georgia.

- **Atlanta, GA**: The city has committed to 100% clean electricity by 2035 (Sierra Club 2020), which is assumed in GIM to apply to the whole Atlanta urban area.

Idaho
We are not aware of clean electricity targets for the state of Idaho.

- **Boise, ID**: The city has committed to 100% clean electricity by 2035 (Sierra Club 2020), which is assumed in GIM to apply to the whole urban area.

Illinois
The state of Illinois has a Renewable Portfolio Standard of 25% by 2025-2026 (NCSL 2020). We are not aware of further clean electricity commitments by the state.

- **Chicago, IL**: The city has committed to 100% clean electricity by 2035 (Sierra Club 2020). Because this is more ambitious target than the state's Renewable Portfolio Standard, Chicago's

commitment is adopted for the whole Chicago urban area for modeling the cleaner electricity scenario in GIM.

Indiana
The state of Indiana has a Renewable Portfolio Standard of 10% by 2025 (NCSL 2020). We are not aware of further clean electricity commitments by the state.

- **Indianapolis, IN**: The city has committed to 100% clean electricity by 2050 (ACCC 2020), which is assumed in GIM to apply to the whole urban area.

Iowa
We are not aware of clean electricity targets for the state of Iowa.

- **Des Moines, IA**: The city has a Strategic Plan which includes "a goal to reduce greenhouse gas emissions 28% below 2017 levels by 2025," but the city does not have clean electricity target (ACEEE 2020), so in GIM it is modeled as not having any clean electricity target.
- **Cedar Rapids, IA**: We are not aware of any clean electricity targets or climate goals.

Kansas
The state of Kansas has a Renewable Portfolio Standard of 20% by 2020 (NCSL 2020). We are not aware of further clean electricity commitments by the state. The urban areas Kansas included in the Gas Index (Wichita, KS, and Lawrence, KS) do not have clean electricity commitments that we are aware of.

Kentucky
We are not aware of clean electricity targets for the state of Kentucky.

- **Louisville, KY**: The city has committed to 100% clean electricity by 2040 (Sierra Club 2020), which is assumed in GIM to apply to the whole urban area.

Louisiana
We are not aware of clean electricity targets for the state of Louisiana.

- **New Orleans, LA**: According to ACEEE 2020, "The New Orleans City Council … approved a binding renewable and clean portfolio standard mandating a net-zero emissions by 2040 and a fully zero-carbon energy portfolio by 2050." In GIM, this is modeled as zero emissions electricity by 2040, and assumed to apply to the whole urban area.

Massachusetts
The state of Massachusetts has passed legislation with a target of 80% reduction in statewide GHG emissions by 2050, and in January 2020, Massachusetts governor Charlie Baker announced a commitment for net-zero emissions statewide by 2050 (Solis 2020).

- **Boston, MA**: According to ACEEE 2020, "Boston has formally adopted goals to reduce greenhouse gas emissions 50% below 2005 levels by 2030 and to be carbon neutral by 2050." In GIM, given the city and state commitments, the Boston, MA, urban area is modeled as achieving 100% clean electricity by 2050.

Maine
In 2019, the state of Maine passed LD 1494, which increased the state's Renewable Portfolio Standard to 80% by 2030 and 100% by 2050 (Sierra Club 2020).

- **Portland, ME**: In GIM, the statewide requirement is applied to the Portland, ME, urban area. We are not aware of citywide targets that are more ambitious than the statewide requirement.

Maryland
The state of Maryland has a target of 50% renewable electricity by 2030 (ACEEE 2020); the business-as-usual case in GIM, based on ReEDS, comes very close to achieving this target, with 48% renewable electricity generated in state in 2030.

- **Baltimore, MD**: ACEEE 2020 reported: "The 2019 Baltimore Sustainability Plan established goals to reduce greenhouse gas emissions 25% below 2007 levels by 2020 and 30% below 2007 levels by 2030," and "We did not find information regarding a community-wide renewable energy goal for the city." Because of the Maryland state target, and the city not having a target that is clearly more ambitious than the state target, then for the Baltimore, MD, urban area, no additional measures are applied in the cleaner electricity scenario.

Michigan
CATF 2020 reported: "In September 2020, Governor Gretchen Whitmer issues Executive Order creating MI Healthy Climate Plan to achieve full statewide carbon neutrality by 2050." In GIM this is modeled as 100% clean electricity by 2050 for all urban areas in the state.

- **Detroit, MI**: We are not aware of clean electricity commitments by the city that go beyond the statewide commitment above.
- **Ann Arbor, MI**: We are not aware of clean electricity commitments by the city that go beyond the statewide commitment above.

Minnesota
The state of Minnesota has a Renewables Energy Standard of 26.5% by 2025 for investor-owned utilities and 25% by 2025 for other utilities (NCSL 2020). We are not aware of further clean electricity commitments by the state.

- **Minneapolis-St. Paul urban area**: Both of the Twin Cities committed to 100% clean electricity by 2030 (Sierra Club 2020). In GIM, this is modeled as applying to the whole urban area.

Missouri
The state of Missouri has a Renewable Portfolio Standard of 15% by 2021 for investor-owned utilities (NCSL 2020). We are not aware of further clean electricity commitments by the state.

- **Springfield, MO**: The city does not have any clean electricity commitments that we are aware of; it is not listed in ACEEE 2020.

Mississippi
We are not aware of clean electricity targets for the state of Mississippi. The only city in Mississippi in the Gas Index, Jackson, MS, does not have any clean electricity commitments that we are aware of; it is not listed in ACEEE 2020.

Montana
The state of Montana had a Renewable Portfolio Standard of 15% by 2015 for investor-owned utilities (NCSL 2020). We are not aware of further clean electricity commitments by the state.

- **Billings, MT**: Does not have clean electricity target that we are aware of; it is not listed by ACEEE 2020. Therefore, the urban area is modeled in GIM as not having any clean electricity commitments beyond what is achieved in the business-as-usual scenario.
- **Missoula, MT**: Committed to 100% clean electricity by 2030 (Sierra Club 2020, ACCC 2020).

Nebraska
We are not aware of clean electricity targets for the state of Nebraska.

- **Lincoln, NE**: We are not aware of clean electricity targets by the city; it is not listed by ACEEE 2020. Therefore, the urban area is modeled in GIM as not having any clean electricity commitments beyond what is achieved in the business-as-usual scenario.
- **Omaha, NE**: ACEEE 2020 reported that Omaha's 2010 Master Plan "includes a goal to increase renewable energy generation to 20% of total energy use in 2010 by 2030 and shift energy generation to renewable resource by 20% every 10 years thereafter." Thus, this is a target for 40% clean electricity by 2040 and 60% by 2050. In the business-as-usual scenario based on the ReEDS scenario for low-price renewables and low-price natural gas, Oklahoma achieves 61% renewable electricity by 2040 and 81% renewable electricity by 2050. Because the business-as-usual scenario goes beyond the targets Omaha, NE, has set, in GIM, no additional measures are modeled for Omaha beyond the business-as-usual case.

Nevada

In 2019, Nevada passed Senate Bill 358 requiring 100% clean electricity by 2050 (Sierra Club 2020). This is assumed to apply to all urban areas in Nevada.

- **Las Vegas, NV**: ACEEE 2020 reported: "We did not find information regarding a community-wide renewable energy goal for the city." Therefore, the urban area is modeled in GIM as following the statewide clean electricity requirement above.
- **Reno, NV**: ACEEE 2020 reported: "We did not find information regarding a municipal renewable energy goal." Therefore, the urban area is modeled in GIM as following the statewide clean electricity requirement above.

New Hampshire

The state of New Hampshire has a Renewable Portfolio Standard of 25.2% by 2025 (NCSL 2020). We are not aware of further clean electricity commitments by the state.

- **Manchester, NH**: We are not aware of clean electricity targets by the city; it is not listed by ACEEE 2020. Therefore, the urban area is modeled in GIM as not having any clean electricity commitments beyond what is achieved in the business-as-usual scenario.

New Mexico

In 2019, the state of New Mexico passed "the Energy Transition Act (SB 489), a bill that will make electricity generation 100 percent carbon-free by 2045 from the state's investor-owned utilities" and for "all rural cooperative utilities by 2050" (Sierra Club 2020).

- **Albuquerque, NM**: According to ACEEE 2020, "The City of Albuquerque has not adopted a sustainability or climate action plan," and the city "does not have a community-wide renewable energy goal." The statewide mandate of 100% clean electricity by 2045 for investor-owned utilities is assumed in GIM to apply to the whole urban area of Albuquerque.

New York

In 2019, the state of New York passed the Climate Leadership and Community Protection Act requiring 100% carbon-free electricity by 2040.

- **Buffalo, NY**: ACEEE 2020 reported: "The city does not have a community-wide renewable energy generation goal." In GIM, the whole urban area is assumed to achieve the statewide target of 100% clean electricity by 2040.
- **New York, NY**: ACEEE 2020 reported: "The city is subsumed to New York State's commitment to 100% clean electricity by 2040." In GIM, the whole New York urban area, including Newark, NJ, is assumed to achieve 100% clean electricity by 2040 based on the New York State requirement. See New Jersey below for information about that state's commitments.

New Jersey

New Jersey passed legislation requiring 50% clean electricity by 2030, and the governor issued an executive order for 100% clean electricity by 2050. The Gas Index does not include any urban areas solely within New Jersey, but does include portions of the state within the New York urban area (including Newark, NJ). ACEEE 2020 reported for Newark: "We did not find information regarding a community-wide renewable energy goal for the city."

Given New Jersey's clean electricity requirement and goal, GIM assumes that the whole of the New York urban area will achieve New York State's requirement of 100% clean electricity by 2040.

North Carolina
The state of North Carolina has a Renewable Portfolio Standard of 12.5% by 2021 (for investor-owned utilities) and 10% by 2018 (for municipal utilities and coops) (NCSL 2020). The state does not have further clean electricity targets that we are aware of.

- **Raleigh, NC**: Wake County, which encompasses Raleigh, NC, committed to 100% clean electricity by 2050 (Sierra Club 2020). In GIM, this is assumed to apply to the whole Raleigh, NC, urban area.

North Dakota
The state of North Dakota had a Renewable Portfolio Standard of 10% by 2015 (NCSL 2020). We are not aware of further clean electricity targets for the state.

- **Fargo, ND**: We are not aware of clean electricity targets by the city; it is not listed by ACEEE 2020.

Ohio
The state of Ohio has a Renewable Portfolio Standard of 8.5% by 2026 (NCSL 2020). We are not aware of further clean electricity targets for the state.

- **Cincinnati, OH:** Committed to 100% clean electricity by 2035 (Sierra Club 2020). In GIM, it assumed the whole urban area (including the portion in Kentucky) will achieve this goal.
- **Cleveland, OH:** Committed to 100% clean electricity by 2050 (Sierra Club 2020). In GIM, it assumed the whole urban area will achieve this goal.
- **Columbus, OH:** Committed to 100% clean electricity by 2022 (Sierra Club 2020). In GIM, it assumed the whole urban area will achieve this goal.

Oklahoma
The state of Oklahoma had a Renewable Energy Goal of 15% by 2015 (NCSL 2020). We are not aware of further clean electricity targets for the state.

- **Oklahoma City, OK**: ACEEE 2020 reported, "The city does not have a community-wide climate mitigation or greenhouse gas emissions reduction goal" and "We did not find information regarding a community-wide renewable energy goal for the city."

Oregon
The state of Oregon passed legislation requiring 50% renewable electricity by 2040 (Oregon Department of Energy 2020).

- **Portland, OR**: The city committed to 100% clean electricity by 2035 (Sierra Club 2020). Additional parts of the Portland urban area are also covered by the same commitment, with Multnomah County and the city of Milwaukie committing to 100% clean electricity by 2035 (Sierra Club 2020). In GIM, the whole Portland, OR, urban area is assumed to achieve 100% clean electricity by 2035.

Pennsylvania

The state of Pennsylvania has an Alternative Energy Portfolio Standard of 18% by 2020-2021 (NCSL 2020). We are not aware of further clean electricity targets for the state.

- Philadelphia, PA: The city has committed to 100% clean electricity by 2035 (Sierra Club 2020). In GIM, it is assumed the whole urban area will achieve the target.
- Pittsburgh, PA: According to ACEEE 2020, "Mayor Peduto pledged the city would achieve a community-wide goal of generating 100% renewable energy by 2030." In GIM, it is assumed the whole urban area will achieve the target.

Rhode Island

The state of Rhode Island has a Renewable Portfolio Standard of "14.5% by 2019, with increases of 1.5% each year until 38.5% by 2035" (NCSL 2020). We are not aware of further clean electricity targets for the state.

- **Providence, RI**: According to ACEEE 2020, the city's Climate Justice Plan "established goals of 50% carbon-free electricity by 2035 and 100% by 2050." In GIM, it is assumed the whole urban area will achieve the target.

South Carolina

The state of South Carolina has a Voluntary Renewables Portfolio Standard of 2% by 2021 (NCSL 2020). We are not aware of further clean electricity targets for the state.

- **Charleston, SC**: According to ACEEE 2020, "In 2017, Mayor Tecklenburg signed on to the Climate Mayors coalition and committed Charleston to a greenhouse gas emissions reduction of 80% below 2002 levels by 2050." Because electricity has proven easier to decarbonize than other sectors, in GIM we model this commitment as achieving 100% clean electricity by 2050. In GIM, it is assumed the whole urban area will achieve the target.
- **Columbia, SC**: The city has committed to 100% clean electricity by 2036 (Sierra Club). In GIM, it is assumed the whole urban area will achieve the target.

South Dakota

The state of South Dakota had a Renewable, Recycled and Conserved Energy Objective of 10% by 2015. We are not aware of further clean electricity targets for the state.

- **Sioux Falls, SD**: We are not aware of clean electricity targets for the city; it is not listed by ACEEE 2020.

Tennessee

We are not aware of clean electricity targets for the state of Tennessee.

- **Memphis, TN**: We are not aware of clean electricity targets adopted by the city. ACEEE 2020 reported in September 2020: "A draft Climate Action Plan was released in 2019, though has not yet been adopted yet"; "The draft Climate Action Plan includes goals to increase carbon-free electricity generation to 75% by 2035 and 100% by 2050." Since this plan has not yet been adopted as of this writing, Memphis is modeled in GIM as not having any clean electricity target.
- **Nashville, TN**: We are not aware of specific clean electricity targets for the city. ACEEE 2020 reports: "The Livable Nashville Recommendations include goals to reduce greenhouse gas emissions 80% below 2014 levels by 2050, with interim goals of a 20% by 2020 and 40% by 2030." Because electricity has proven easier to decarbonize than other sectors, in GIM we model this commitment as achieving 100% clean electricity by 2050. In GIM, it is assumed the whole urban area will achieve the target.

Texas

The state of Texas has a Renewable Portfolio Standard with a requirement of 10,000 MW by 2025, which had already been achieved in 2020 (NCSL 2020). We are not aware of additional state-level clean electricity commitments.

- **Austin, TX:** According to ACEEE 2020, the 2015 Austin Community Climate Plan "established a citywide 2050 net zero greenhouse gas emissions goal." In addition, the main utility in the city, Austin Energy, "established goals to procure at least 55% of customer consumption from renewable energy resources by 2025 and commit to 65% by the end of 2027" (ACEEE 2020). Given these commitments, GIM models the Austin urban area as achieving 100% clean electricity by 2050.
- **Dallas-Ft. Worth, TX**: According to ACEEE 2020, "Dallas' Comprehensive Environmental & Climate Action Plan established a goal of achieving community-wide carbon neutrality by 2050." However, ACEEE 2020 reports, "The city does not have a renewable energy goal." For Ft. Worth, ACEEE 2020 reported: "The City of Fort Worth has not formally adopted a sustainability or climate action plan" and "We did not find information regarding a community-wide renewable energy goal for the city." Nonetheless, since Dallas is the major city in the urban area, in GIM it is assumed that the whole urban area will achieve the goal of carbon neutrality by 2050, and that this will involve 100% clean electricity by that year.
- **Houston, TX**: ACEEE 2020 reports: "Houston's Mayor Parker pledged the city to an 80% reduction of greenhouse gas emissions below 2005 by 2050." Because electricity has proven easier to decarbonize than other sectors, in GIM we model this commitment as achieving 100% clean electricity by 2050. In GIM, it is assumed the whole urban area will achieve the target.
- **San Antonio, TX**: According to ACEEE 2020, "The San Antonio Climate Ready plan establishes a goal to achieve carbon neutrality by 2050." In GIM, it is assumed that carbon neutrality would require 100% clean electricity, and it is assumed the whole urban area will achieve the target.

Utah

The state of Utah has a Renewable Portfolio Standard with a requirement of 20% renewable electricity by 2025 (NCSL 2020). We are not aware of additional state-level clean electricity commitments.

- **Salt Lake City, UT**: Salt Lake City has committed to 100% clean electricity by 2030, as has Salt Lake County (Sierra Club 2020). In GIM, it assumed the whole Salt Lake City urban area will achieve the target.

Virginia

The state of Virginia passed legislation requiring 100% clean electricity by 2050.

- **Richmond, VA**: ACEEE 2020 reported: "We did not find information regarding a quantifiable community-wide renewable energy goal for the city, but the 2012 RVAgreen plan included a general goal to increase renewable energy installations, and the RVAgreen 2050 planning process will set community-wide renewable energy goals." GIM models the Richmond, VA, urban area as achieving the statewide clean electricity target. If the city later adopts a more ambitious target, that can be incorporated into GIM in the future.
- **Virginia Beach, VA**: ACEEE 2020 reported: "The city does not have a climate mitigation or greenhouse gas emissions reduction goal" and "We did not find information regarding a community-wide renewable energy goal for the city." GIM models the Virginia Beach, VA, urban area as achieving the statewide clean electricity target.

Vermont

In 2015, Vermont passed legislation requiring 75% clean electricity by 2032 (WRI 2019).

- **Burlington, VT**: The city already achieved 100% clean electricity by 2018, if not earlier, according to the city's utility (Burlington Electric 2020). In GIM, it assumed that this applies to

the whole Burlington, VT, urban area. Because the city has already achieved 100% clean electricity, this is applied in both electricity scenarios (business-as-usual and commitments).

Washington

In 2019, Washington passed S.B. 5116, which "requires all electricity generation in the state to be carbon neutral by 2030 and completely carbon free by 2045" (CATF 2020).

- **Seattle, WA**: According to ACEEE, "As hydroelectricity powers almost all of Seattle, the city does not have a renewable energy goal; however, the Seattle Climate Action Plan states the intention to maintain Seattle City Light's status as a carbon-neutral utility." The City of Seattle states that the utility Seattle City Light's electricity is already 100% carbon neutral, generating more than 90% of its power from hydroelectricity, and emissions from the remaining generation are offset (City of Seattle 2020). In GIM, Seattle is modeled as having already achieved 100% clean electricity, for both electricity scenarios (business-as-usual and commitments).

Wisconsin

In 2019, Wisconsin's governor issued an executive order for 100% clean electricity by 2050 (WRI 2019).

- **Madison, WI**: According to Sierra Club 2020, in 2018, the city adopted a target of 100% clean electricity, but no target year was stated. In GIM, the Madison urban area is modeled as achieving the statewide target of 100% clean electricity by 2050.
- **Milwaukee, WI**: ACEEE 2020 reported "We did not find information regarding a community-wide renewable energy goal for the city." In GIM, the Milwaukee urban area is modeled as achieving the statewide target of 100% clean electricity by 2050.

West Virginia

We are not aware of clean electricity targets for the state of West Virginia. The state passed a Renewable Portfolio Standard in 2009, but it was repealed in 2015 (NCSL 2020).

- **Charleston, WV**: We are not aware of city-level clean electricity commitments; the city is not listed by ACEEE 2020.

Wyoming

We are not aware of clean electricity targets for the state of Wyoming.

- **Cheyenne, WY**: We are not aware of city-level clean electricity commitments; the city is not listed by ACEEE 2020.

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