Author preprint
Final version available at https://doi.org/10.1016/j.jclepro.2019.03.096

Supplementary Material for

Three Considerations for Modeling Natural Gas System Methane Emissions in Life Cycle Assessment

Emily A. Grubert, Adam R. Brandt

correspondence to: gruberte@gatech.edu

This PDF file includes:

Supplementary Text (9 pages)
Tables S1 to S3
Figure S1

Other supplementary information for this manuscript includes the following:

Data File S1 as Excel Workbook: Leakage Emissions in Key Sectors

Glossary of Nonmetric Natural Gas Units
scf – standard cubic feet
mcf – thousand cubic feet
mmscf – million standard cubic feet
Tcf – trillion cubic feet

S1 Methane Leakage in Life Cycle Inventories

This section supplements Section 3.1 in the main text with detail on how the leakage rates in the EPA greenhouse gas inventory, EIO-LCA, ecoinvent 3.5, and USLCI (presented in Table 1 in the main text) were calculated. This analysis reports leakage as a cumulative mass percentage of gross withdrawals of methane that reach a given life cycle stage, i.e., the embodied mass-based methane leakage (as mass of methane leaked divided by mass of methane withdrawn) from cradle to gate by process.

S1.1 EPA Greenhouse Gas Inventory

Calculations can be found in worksheet “EPA 2013, leakage” in Data File S1.

Mass-based leakage percentages by stage for the 2013 EPA greenhouse gas inventory are calculated using the following process:

1) Determine total mass of methane emitted by life cycle stage, as published in the 2015 EPA greenhouse gas inventory for 2013. Given that emissions are reported as CH_4 mass, no further conversions are necessary.
2) Determine total mass of methane reaching each life cycle stage in 2013 by updating Supplementary Data File S1 of “Methane leakage from North American natural gas systems” (Brandt et al., 2014) to reflect 2013 Energy Information Administration (EIA) data on natural gas system flows (tab “NG system flows 2011”). The same EIA data sources as those referenced in the original file are used, but with values for 2013 rather than 2011. Volume-to-mass conversion factors by stage are the same as those used in the original source.
3) Divide results from step (1) by results from step (2) to find mass-based percentage leakage by stage.

<u>Values used in calculations</u>
The “Production” leakage is based on the 2015 EPA greenhouse gas inventory for 2013 Annex 3, Table A-133, “2013 Data and CH4 Emissions (Mg) for the Natural Gas Production Stage, by NEMS Region). Total net emissions are given as 1,879.5 kilotonnes. Production stage leakage is estimated at 0.39% by mass, which is also the cumulative leakage through this stage.

The “Processing” leakage is based on the 2015 EPA greenhouse gas inventory for 2013 Annex 3, Table A-136, “2013 Data and CH4 Emissions (Mg) for the Natural Gas Processing Stage). Total net emissions are given as 906.4 kilotonnes. Processing stage leakage is estimated at 0.24% by mass on a gross withdrawal basis, for a cumulative leakage estimate of 0.63% for natural gas that is both produced and processed.

The “Transmission/Storage” leakage is based on the 2015 EPA greenhouse gas inventory for 2013 Annex 3, Table A-137, “2013 Data and CH4 Emissions (Mg) for the Natural Gas

Transmission Stage). Total net emissions are given as 2,176.4 kilotonnes. Transmission/storage stage leakage is estimated at 0.37% by mass on a gross withdrawal basis, for a cumulative leakage estimate of 1.0% for natural gas that is produced, processed, and shipped in transmission lines.

The "Distribution" leakage is based on the 2015 EPA greenhouse gas inventory for 2013 Annex 3, Table A-138, "2013 Data and CH4 Emissions (Mg) for the Natural Gas Distribution Stage). Total net emissions are given as 1,332.5 kilotonnes. Distribution stage leakage is estimated at 0.43% by mass on a gross withdrawal basis, for a cumulative leakage estimate of 1.4% for natural gas that is produced, processed, and shipped through both the transmission and distribution systems.

The 2015 EPA greenhouse gas inventory for 2013, like the other inventories evaluated in this work, does not include end user leakage.

Note that the 2015 EPA greenhouse gas inventory for 2013's total estimated leakage rate for natural gas is 1.3% by mass on a gross withdrawal basis, given that different life cycle stages have different amounts of natural gas flow through them. For example, the embodied emissions from natural gas that reaches the distribution system are higher than the average embodied emissions, while the embodied emissions from natural gas consumed for pipeline use are lower than the average embodied emissions.

S1.2 EIO-LCA

Calculations can be found in worksheet "EIO-LCA, leakage" in Data File S1.

The EIO-LCA database reports methane emissions as mass of carbon dioxide equivalent using the IPCC Third Assessment Report (TAR) global warming potential (GWP) of 23. Although mass of methane is therefore relatively straightforward to calculate—reported kilograms of CO_2e as methane divided by 23 gives kilograms of methane—EIO-LCA reports emissions per unit of economic activity. Therefore, calculating leakage rates requires the conversion of 2002 US dollars (USD) to a mass of natural gas, then to a mass of methane. To ensure that this analysis captures the EIO-LCA allocations among oil, natural gas, and other products in the multiproduct processes of "oil and gas extraction" and "pipeline transportation," data are drawn from the process closest to consumers: "Natural gas distribution," Sector 221200.

Analysis proceeds as follows:

1) Download emissions data associated with the EIO-LCA sector "Natural gas distribution."
2) Identify natural gas supply chain sectors in EIO-LCA, as "Oil and gas extraction," "Pipeline transportation," and "Natural gas distribution," and convert reported mass of CO_2e emissions as methane per million 2002 USD to mass of methane emissions per million 2002 USD via the IPCC TAR GWP for methane, 23.
3) Find the 2002 price of distributed natural gas for use in converting value of resource to volume of resource: assume distribution price is $7.26/distributed mcf (USD2002), based on the average of residential and commercial sales prices (https://www.eia.gov/dnav/ng/NG_PRI_SUM_DCU_NUS_A.htm). A comment on page 5 of the EIO-LCA documentation indicates that fuel consumption is being calculated

based on expenditures in the “Natural gas distribution” sector, so calculations are made assuming 2002$1 million of activity in the “Natural gas distribution” sector is approximately equivalent to 2002$1 million of natural gas sold at distribution prices, rather than 2002$1 million of added value from distribution. This assumption—$7.26/distributed mcf × 13.6 distributed Tcf—produces an estimate that “natural gas distribution” has total activity worth 2002$99 billion, 6% higher than the documented activity value of 2002$93 billion in the EIO-LCA tool. See Data File 1 for calculation and full assumptions.

4) Determine mass of methane per volume of natural gas produced, using distribution-system conversion from Brandt et al. (2014) of 55.85 mmscf natural gas / Gg CH_4. Assume total methane withdrawn = methane emitted + methane sold.
5) Calculate mass-based leakage rate based on converted methane mass from step (2) and converted withdrawn methane mass per million 2002 USD from step (4).

Based on the calculations described above, the mass-based methane leakage rate per unit methane withdrawn for the natural gas system reflected in EIO-LCA is 0.57% for production (contribution from “Oil and Gas Extraction”), 0.34% for transmission (contribution from “Pipeline transportation”), and 0.50% for distribution (contribution from “Natural Gas Distribution”). Cumulatively for each stage, then, assuming natural gas reaching a downstream stage has participated in the upstream stages, leakage is estimated at 0.57% for production, n/a for processing, 0.91% for transmission/storage, and 1.4% for distribution. An additional 0.06% of methane leakage (mass percent of gross withdrawals) is embodied through non-natural gas processes, including coal mining, likely related to infrastructural demands in EIO-LCA.

Note that EIO-LCA documentation about the “Pipeline transportation” sector is inconsistent with regard to whether it includes natural gas and crude oil pipelines or not. The web tool indicates that it does not, while the written documentation indicates that it does. Given this discrepancy, we rely on calculations based on the decomposed “Natural Gas Distribution” sector data to estimate leakage. Calculations can also be made based on individual subsectors, however, using assumptions about prices, volumes, and allocation techniques. Data File S1, “EIO-LCA, leakage” includes calculations based on the individual subsectors “Oil and Gas Extraction,” “Pipeline transportation,” and “Natural Gas Distribution,” using both a financial allocation approach and an EPA GHGI allocation approach for illustration. These result in roughly or exactly equal estimates for “Oil and Gas Extraction” (0.51% or 0.56% leakage, versus 0.57% based on the “Natural Gas Distribution” inventory) and “Natural Gas Distribution” (0.50% leakage in all cases), but estimates for “Pipeline transportation” are very different: 0.42% for financial allocation or 1.6% for GHGI-based allocation, versus the implied 0.34% based on native EIO-LCA allocation for the “Natural Gas Distribution” inventory. This result suggests that some other unstated allocation procedure is being used within EIO-LCA to determine the methane leakage associated with pipeline transportation of natural gas. See Data File S1 for full calculations and assumptions.

S1.3 USLCI
Calculations can be found in worksheet “USLCI, leakage” in Data File S1.

The USLCI database reports methane emissions in mass units, which means that no further conversions of the leakage values are needed. The output products, however, are reported in a variety of units that do require further conversions. Natural gas production is given in volume (for “natural gas, at extraction site”) and mass (for “natural gas, extracted”) of natural gas, which requires both conversion between mass and volume and conversion between natural gas and methane withdrawals. Other relevant processes are reported in volume (for “gas, natural,” “natural gas, processed, at plant,” “natural gas, combusted in industrial boiler,” and “natural gas, combusted in industrial equipment”), mass (for “gas, natural, 49.8 MJ/kg, in ground”), and t*km (for “transport, pipeline, natural gas”), which this work interprets to be metric tonnes of natural gas transported 1 kilometer in the transmission system. Gross withdrawals per unit of delivered gas at any given stage were adjusted to account for consumption of natural gas used in the life cycle of natural gas production, which was a minor (<5%) difference.

Converting natural gas withdrawals to methane withdrawals for USLCI proceeds via estimation of a natural gas composition that produces both a higher heating value (HHV) of 49.8 MJ/kg (based on one of the stated flow names) and an approximate mass of 0.74 kg/standard cubic meter (Sm^3) for the overall natural gas (based on documentation received from USLCI via the contact form). Available documentation did not clarify whether the 49.8 MJ/kg value is higher or lower heating value, but HHV is assumed based on typical US practice and the stated mass of the natural gas. See Data File S1, “USLCI, leakage,” for details.

As with the ecoinvent database, USLCI has some definitional discrepancies that might be confusing to users. Namely, “natural gas, extracted” is a different process than “natural gas, at extraction site.” The distinction between the two is not clear. The documentation indicates that USLCI distinguishes between natural gas extracted from natural gas wells and natural gas extracted from all wells (e.g., including from oil wells as associated gas), but both “natural gas, extracted” and “natural gas, at extraction site” indicate that they cover both types of natural gas production. However, the two processes are quite different: “natural gas, extracted” has a mass methane leaked per mass methane extracted rate of 0.34%, while “natural gas, at extraction site” has a leakage rate of 1.4%. Based on the presumed use of USLCI data in ecoinvent, given that NREL is a named source for the “natural gas, production (US)” process in ecoinvent (see S1.4), it is likely that the “natural gas, at extraction site” is the process intended to cover natural gas from natural gas-only wells. This assumption is corroborated by the “Description” in USLCI:

> “Natural gas is commonly co-extracted with crude oil. However, there are enough differences between crude oil and natural gas extraction to merit separate data modules for each product.”

The “Technology Description” reads:

> “Includes data for natural gas extracted from onshore and offshore wells. Includes data for natural gas co-extracted with crude oil as well as for wells that produced only natural gas.”

However, the “natural gas, extracted” process description provides much more detail on allocation between oil and natural gas, and this work takes that process to be the more representative of USLCI’s natural gas processes. Based on that documentation, USLCI allocates emissions based on mass, not energy value or financial value, which also explains the much lower methane emissions from the combined process. Given that crude oil is much heavier than natural gas (close to a tonne/cubic meter, as a liquid, versus less than a kilogram/cubic meter, as a gas), this choice would tend to allocate essentially all methane emissions from wells coproducing oil and natural gas to oil. Even assuming no methane emissions are allocated to natural gas from coproducing wells does not fully explain the more than 4× discrepancy between the two values when compared with the ratio of natural gas produced from oil versus natural gas-only wells, even assuming old data are in use. This discrepancy is potentially significant, particularly because the difference between “natural gas, extracted” and “natural gas, at extraction site” is not clear from the processes’ titles. Similarly, though less importantly for this analysis, the difference between processes like “natural gas, combusted in industrial boiler” and “natural gas, combusted in industrial equipment” is not obvious to users.

This analysis uses the “natural gas, extracted” process (i.e., natural gas from all US sources) as the most relevant production process. The other relevant processes from the USLCI are “natural gas, processed, at plant, m^3,” with process leakage calculated as 0.20%, and “transport, pipeline, natural gas,” with process leakage calculated as 0.37%.[1] For the “transport, pipeline, natural gas” process, the functional unit is a tonne-kilometer. This analysis assumes a given tonne of natural gas travels 765 kilometers in the transmission system, based on documentation provided by USLCI upon request through the contact form. Cumulatively, then, USLCI data indicate that a unit of natural gas that is produced, processed, and transported through the transmission pipeline will experience an estimated 0.92% leakage as mass of methane leaked per mass of methane withdrawn. There are no distribution or end use leakage estimates in USLCI.

S1.4 ecoinvent 3.5
Calculations can be found in worksheet “ecoinvent 3.5, leakage” in Data File S1.

The life cycle inventory database ecoinvent 3.5 reports methane leakage in kilograms per cubic meter of natural gas. This analysis thus converts the volumetric units to mass units, then mass units of natural gas to mass units of methane, so as to express leakage on a mass basis. The conversion factor given in ecoinvent 3.5 is 0.84 kg/m^3 of high pressure natural gas. Note that based on molecular weights of natural gas components, this kg/m^3 is likely the density of raw gas (i.e., before processing into pipeline quality gas) per cubic meter at standard temperature and pressure (Sm^3), not mass of pipeline gas at pipeline pressures. That is, the cubic meter of high pressure natural gas referenced as the output is likely a cubic meter of raw natural gas at standard temperature and pressure (STP). This point that the volume is based on STP is not obvious from documentation, which notes only that the unit is a “cubic meter” and the reference product is “natural gas, high pressure.” The effect is that users assuming the volume of “natural gas, high pressure” is at high pressure will substantially overestimate the amount of methane involved. See Data File S1 for calculations and assumptions used for this analysis.

[1] USLCI includes a power plant-oriented process, “electricity, natural gas, at power plant” with very low methane leakage: see Data File S1, “USLCI ngas processes.”

The ecoinvent natural gas data reported in this analysis are the life cycle inventory data for "natural gas production (US)" and "petroleum and gas production, on-shore (US)" (production phase) and "market for natural gas, high pressure (US)" (transmission/storage phase). Unit process data are also reported in Data File S1. Note that "natural gas production (US)" contributes 70% of the "natural gas, high pressure" to the overall "market for natural gas, high pressure (US)" system, while "petroleum and gas production, on-shore (US)" contributes 30%. This allocation is meaningful, given that "natural gas production (US)" displays a life cycle inventory leakage rate of 1.8% (unit process leakage of 1.8%), while "petroleum and gas production, on-shore (US)" displays a life cycle inventory leakage rate of 0.10% (unit process leakage of 0.00%). The 70% to 30% split between "natural gas production (US)" and the natural gas-allocated portion of "petroleum and gas production, on-shore (US)" is apparently based on 2014 data from BP. EIA data[2], however, show that combined on- and offshore natural gas production from oil wells is less than 20% of US production as of 2017. Note that the current 70-30 split was implemented in ecoinvent 3.4: previously, the split was recorded as 44% to 56%, with the overall effect that ecoinvent data predating version 3.4 indicate a much lower life cycle mass leakage of methane for US natural gas (1.2% rather than the 1.6% we report). Data for "natural gas production (US)" are based on NREL data for production including both associated and nonassociated natural gas, plus offshore production, supplemented with German data. These input data have apparently been updated to reflect on-shore natural gas production only, but how that was done is unclear. Data for "petroleum and gas production, on-shore (US)" are based primarily on data from the Niger Delta in Nigeria from 1999 and 2000, a region famous for flaring rather than selling the natural gas produced alongside oil[3], and far from analogous to US natural gas production regions. Note also that while this process does not have any methane emissions listed, "natural gas, vented" is included as an input from the technosphere. If this venting were counted as an emission, it would indicate a leakage rate of about 0.1% of production.

The fact that all three processes discussed here—"natural gas production (US)," "petroleum and gas production, on-shore (US)", and "market for natural gas, high pressure (US)" have the same reference product—one cubic meter of "natural gas, high pressure" that appears to actually be 1 Sm^3 of raw natural gas—is confusing and likely challenging for practitioners to interpret, especially for LCA practitioners who are not focused specifically on natural gas but use natural gas process data to evaluate other product systems.

S2 The Location of Methane Leakage

Data on the precise source of natural gas supply for individual facilities are difficult to acquire, potentially due to the large number of facilities and sensitivity of locational data for pipelines carrying highly combustible materials like natural gas. This supplementary section corroborates the conventional wisdom that natural gas-fired power plants generally receive supply from the high pressure natural gas system (personal communication, Dynegy Investor Relations, March

---

[2] Natural Gas Gross Withdrawals from Oil Wells [WWW Document], 12.31.18. URL https://www.eia.gov/dnav/ng/ng_prod_sum_a_EPG0_FGO_mmcf_a.htm (accessed 1.25.19).

[3] Anejionu, O.C.D., Whyatt, J.D., Blackburn, G.A., Price, C.S., 2015. Contributions of gas flaring to a global air pollution hotspot: Spatial and temporal variations, impacts and alleviation. Atmospheric Environment 118, 184–193. https://doi.org/10.1016/j.atmosenv.2015.08.006

2018) with a mapping exercise showing the approximate locations of US natural gas-fired power plants and US natural gas transmission supply lines. Note that the following analysis includes data only for interstate and intrastate pipelines included in the Energy Information Association (EIA) shapefile (see below), which are likely transmission lines only, not high pressure laterals that are also common as supply lines for power plants.

The geographic information system (GIS) data used for this analysis are:

- Pipeline locations: "Natural Gas Interstate and Intrastate Pipelines," updated 23 February 2018, https://www.eia.gov/maps/layer_info-m.php
- Power plant locations: "Power Plants," updated 10 January 2018, https://www.eia.gov/maps/layer_info-m.php

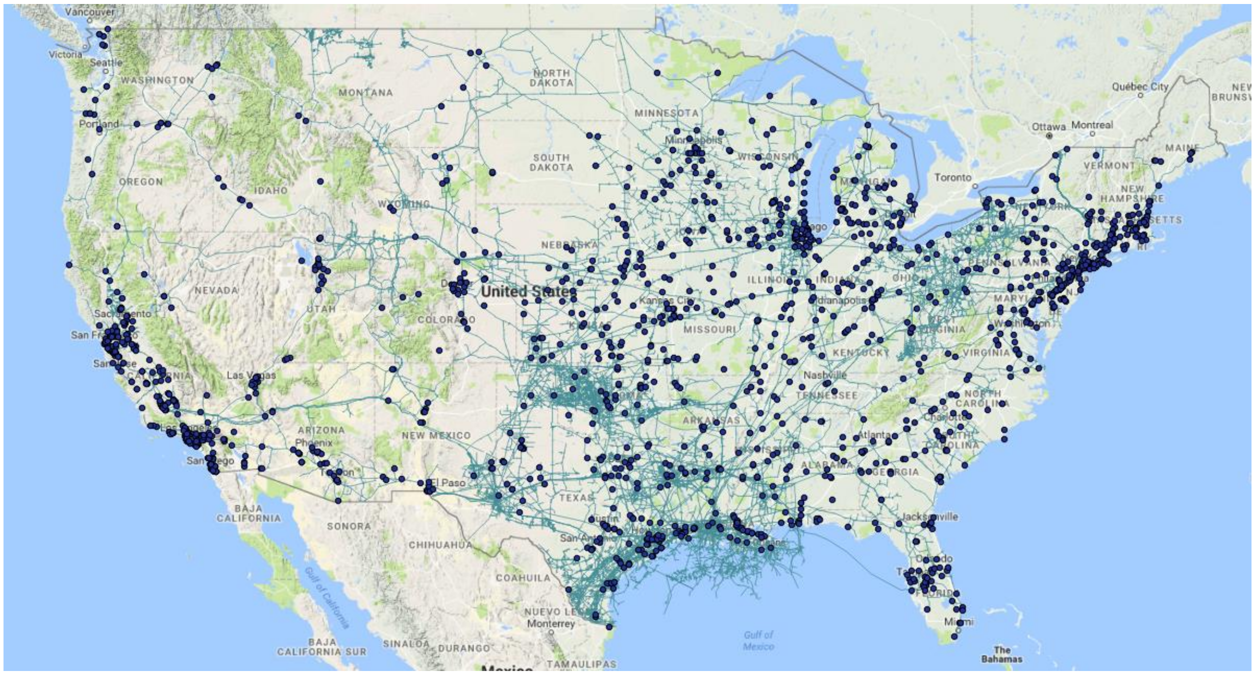
Analysis proceeded as follows. The pipeline and power plant location shapefiles were loaded into QGIS, an open source GIS software. The "Power Plants" layer was then filtered to natural gas-fired power plants by selecting only those entries with "PrimSource" = 'natural gas' in QGIS. Then, QGIS was used to select natural gas-fired power plants within 1, 2, 5, and 10 miles of a pipeline. These selections were exported to Microsoft Excel and correlated with EIA 923 final data for 2016 (https://www.eia.gov/electricity/data/eia923/) to determine the total generation associated with each plant. Table S3 shows the number of plants, capacity, and generation for plants by distance from a major pipeline, alongside the percentage of total natural gas-fired plant number, capacity, and generation for context.

Table S3. Natural gas-fired power plant count, capacity, and generation by distance from a major pipeline

	Count	% of Count	Capacity (GW)	% of Capacity	2016 Generation (GWh)	% of 2016 Generation
Within 1 mile	575	34%	188	43%	5.78×10^5	44%
Within 2 miles	893	52%	276	63%	8.22×10^5	62%
Within 5 miles	1295	76%	353	80%	1.07×10^6	81%
Within 10 miles	1498	88%	395	90%	1.19×10^6	90%
Total	1706	100%	439	100%	1.33×10^6	100%

Figure S1 shows US natural gas-fired power plants' locations in relation to the major pipeline system.

Figure S1. US natural gas-fired power plants and the interstate and intrastate pipeline system



Most US natural gas-fired power plants, natural gas-fired power capacity, and natural gas-fired generation are within two miles of a major pipeline, and about 90% of generation is within 10 miles of a major pipeline. Especially given that high pressure laterals are likely excluded from the GIS layers, the rule of thumb assumption that natural gas-fired power plants are supplied by the transmission system or other high pressure systems that are subject to similar safety standards (often associated with higher priority for leak repair) rather than the distribution system appears reasonable.