Geospatial Life Cycle Analysis of Greenhouse Gas Emissions from US Liquefied Natural Gas Supply Chains

Yuanrui Zhu[1,2], David T. Allen[1,3], and Arvind P. Ravikumar[1,2]*

[1]Energy Emissions Modeling and Data Lab (EEMDL), The University of Texas at Austin, Austin TX 78712
[2]Department of Petroleum and Geosystems Engineering, The University of Texas at Austin, Austin TX 78712
[3]Department of Chemical Engineering, The University of Texas at Austin, Austin TX 78712

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ABSTRACT: Growth in US liquefied natural gas (LNG) exports have increased concerns about the climate impacts of methane leakage along LNG supply chains. Current life cycle analysis (LCA) models of US LNG supply chains are based on emissions estimates in national inventories that have been demonstrated to significantly underestimate emissions. In addition, recent top-down measurements of methane emissions exhibit significant sub-national spatial and temporal variation across oil and gas (O&G) basins. In this study, we develop a geospatial, measurement informed LCA model that incorporates recent top-down methane measurements to examine regional differences in greenhouse gas (GHG) emissions intensity of US LNG supply chains for delivery to Europe and Asia. For every megajoule of LNG shipped from the US, the energy allocated GHG emissions intensity of the Permian-UK LNG supply chain is 42% higher compared to the Marcellus-UK LNG supply chain. Disparities in LNG emissions intensity across source basins can be directly attributed to higher measured methane emissions compared to inventory estimates. Developing measurement informed, supply-chain specific lifecycle GHG emissions assessments is critical to enabling a global market for differentiated natural gas.

INTRODUCTION

Natural gas (NG), as a substitute for coal, releases less than half the amount of CO_2 on combustion and has lower emissions of air pollutants such as sulfur dioxide and particulate matter. Therefore, NG has been touted as a bridge fuel to a low or zero-carbon future until near zero emissions technologies can displace fossil fuel use.[1–4] Compared with pipeline gas, LNG enables long-distance transportation across continents, thereby making NG a truly global commodity. Global events such as the Russian invasion of Ukraine has accelerated recent trends in expansion in LNG export and import terminals.[5,6] Between 2020 and 2030, global liquefaction capacity has increased from 439 million tonnes per annum (MTPA) in 2020 to 1079 MTPA, respectively. The United States accounts for 48% of all in-development growth of global export capacity and is the largest LNG exporter in the world.[7]

Global concern over the climate impacts of growing LNG trade has led to a growing number of regulatory and voluntary initiatives to address methane emissions from the oil and gas (O&G) sector. Over 150 countries recently pledged to reduce methane emissions by 30% by 2030 as part of the Global Methane Pledge.[8,9] Several countries have proposed or finalized regulations to reduce methane emissions.[10,11] As one of the largest LNG importing markets, Europe announced a methane import standard that would require all importers selling into the European market to meet specific thresholds of greenhouse gas emissions intensity starting from 2027.[12] The US Department of Energy, along with other major LNG importing and exporting countries, is developing a shared monitoring, measurement, reporting, and verification (MMRV) framework for global differentiated gas.[13] Responding to market signals and public pressure, some producers, purchasers, and investors have pushed, on a voluntary basis, to certify some delivered LNG or specific LNG production processes as 'responsibly-sourced' or 'green'.[14] Whether regulatory or voluntary, differentiating global LNG supply chains requires highly spatially resolved, accurate, and timely information on supply chain GHG emissions.

Accurate estimation of GHG emissions across LNG supply chains becomes critical to compete in a carbon constrained world. Recently, many studies have investigated the life cycle GHG emissions associated with LNG supply chains.[15–21] These studies typically employ conventional national emissions inventories such as the US Environmental Protection Agency GHG Inventory to estimate supply chain emissions. However, recent studies have demonstrated that national emission inventories, such as the US EPA's GHG Inventory, significantly underestimate methane emissions compared to top-down measurements.[22,23] Analysis of recent field measurements in the US and Canada suggest that the measured emissions of methane from the oil and gas supply chain are 60% higher than the official inventory estimate.[24–26] Furthermore, recent top-down measurement campaigns demonstrate significant differences in emissions across US O&G basins, ranging from 0.75% to 9.63% as a fraction of NG production.[27] Field campaigns in the Marcellus basin show that the gas production normalized emission rate varies between 0.3 and 1.4%.[28–30] In the Permian basin, O&G operators are reported to emit 3.7%-9.4% of the NG normalized to gas production, which is roughly 3 to 10 times the average emission rate in other US major O&G basins.[31–33] Therefore, inventory-based methane emission estimates combined with sensitivity analysis is unable to meet the growing need for accurate measurement informed emission estimation, and measurements should be incorporated into LCA studies.[34–37]

In this study, we develop a geospatial, basin-specific life cycle GHG emission framework for US LNG supply chains. We illustrate this using case studies of US LNG exports to Europe and Asia with NG sourced from the Marcellus and Permian basins. The key innovation in the methodology is that we incorporated top-down measured methane emissions data across different basins within the LCA framework through a measurement informed inventory estimate. The availability of measurement-informed, geospatial assessment tools can enable differentiation of global LNG supply chains.

METHODS

This study develops a geospatial life cycle assessment of GHG (CO_2 and CH_4) emissions of LNG supply chains from US basins delivered to Asia and Europe. The analysis considers emissions from production, gathering and boosting, processing, transmission, liquefaction, and shipping stages of the supply chain, and excludes emissions associated with re-gasification and end-use (SI Figure S1). Both scope-1 and scope-2 emissions are included in the model – the system boundary includes the life cycle impacts of diesel use, local grid power, and fuel gas at each stage. The functional unit is 1MJ LNG delivered to the import terminal. We present four case studies of LNG sourcing from the Marcellus and Permian basins to UK and China and compare them on an equivalent MJ LNG delivered basis. We quantify emissions of CH_4 and CO_2 in terms of CO_2-equivalents using 100- and 20-year global warming potentials (GWP) based on the Intergovernmental Panel on Climate Change (IPCC) fifth assessment (AR5) report.[38] The results in the main text are based on 100-year GWP, and the results based on 20-year GWP can be found in the SI section S10. Data sources for each stage of the supply chain are prioritized in the following order: operational and measurement data published in peer-reviewed literature, estimates provided by state or federal governments, and publicly available data in the non-peer-reviewed literature.

LNG supply chain

We design four LNG supply chains with the NG produced in the Marcellus and Permian basins and shipped to UK and China to illustrate the difference in emissions. The NG production region that are included in this study are northeastern Marcellus basin and Permian basin (including both the Midland and Delaware sub-basins). The Marcellus basin is dominated by NG production, with methane content of northeastern dry gas region much higher than that of southwestern wet gas region. However, the Permian basin produces crude oil, lease condensate, and produced gas across the whole basin. The selection of northeastern Marcellus and Permian basin exemplify a wide range of NG production scenarios. The NG produced from both northeastern Marcellus and Permian basins are transported by pipeline to the Sabine Pass Liquefaction (SPL) terminal before being shipped to the UK and China. SPL is chosen for this case study because it is the largest liquefaction facility in US and accounts for one third US total liquefaction capacity. The measurements and inventory data for each LNG supply chain are estimated for study region average (SI section S1). Detailed information on datasets for processes and emissions sources are provided below and expanded in the Supplementary Information.

Upstream production, gathering and boosting: The upstream stage includes well drilling through gas dehydration and compression (SI section S2). In the Marcellus basin, CO_2 emissions associated with fuel use including diesel and fuel gas were obtained from the XTO-operated facilities in that region,[17] and the inventory-based methane emission estimates were derived from the integration of several studies [39–41] and replaced by an measurement informed methane emission estimates from a field campaign in the Northeastern Marcellus basin[28]. For the Permian basin, we employed the framework of GHG emission in a recent NETL report on lifecycle analysis of US natural gas supply chains,[40] and replaced the inventory-based methane emissions data with an aggregated measurement informed emissions estimates from peer-reviewed literature[33,42]. The measured methane emission rates are shown in Table 1.

Processing: With a high degree of electrification of processing facilities in the Marcellus basin, most of the energy required for the processing stage comes from electricity, with only a small portion from the combustion of NG.[17] Emissions factors for electricity use are based on the PJM interconnection average grid emissions for 2022.[43] On the contrary, for the less electrified Permian basin, all the energy required for processing comes from the combustion of NG (SI section S3). For methane emissions, we adopted data form peer-reviewed methane emission measurements[33,42,44] to replace the US average methane leakage profile of processing plant[45,46] for both basins.

Table 1. Measurement informed and inventory-based methane emission intensities

Basin	Parameter	Upstream Production, gathering and boosting	Processing	Total
Northeastern Marcellus	Barkley et al. 2017	0.40%	/	0.40%
	Gross gas production normalized CH_4 emission rate	0.40%	0.14%[a]	
	Energy normalized CH_4 emission rate	0.39%	0.13%	
	Measurement informed CH_4 emission intensity (g CO_2e/MJ throughput)	2.38	0.81	
	Inventory-based CH_4 emission intensity (g CO2e/MJ)	1.27	0.14	

Permian	Zhang et al. 2020[b]	3.52%	0.19%	3.71%
	Gross gas production normalized CH_4 emission rate	3.52%	0.19%	
	Energy normalized measured CH_4 emission rate	1.10%	0.14%	
	Measurement informed CH_4 emission intensity (g CO_2e/MJ throughput)	4.79	0.81	
	Inventory-based CH_4 emission intensity (g CO2e/MJ)	1.63	0.27	

[a]The measured methane emission rate from processing stage at northeastern Marcellus is not available. Therefore, we use the lower bound of measured methane emission rate from processing stage at southwestern as an approximation. For more detailed information, refer to SI section S9.

[b]The total estimated methane emission rate associated with O&G production are allocated to production, gathering and boosting, and processing stages based on the adjusted GHGRP reported methane emissions in 2018.

Transmission: We include the emissions from transmission pipelines and compressor stations and exclude emissions from storage facilities since we do not expect seasonal variation in LNG demand. GHG emissions in the transmission sector are estimated based on engineering calculations of fuel use at compressor stations and fugitive and vented emissions at both compressor stations and pipelines. Fuel use is a function of number and type of compressor units and varies by distance between the processing plant and end-use destination. Methane emissions for the transmission sector are calculated from a nationally representative peer-reviewed study.[47] The primary difference between Marcellus and Permian supply chains at transmission stage is the number of compressor stations required for different transportation distances. The required number of compressor stations from Marcellus basin to SPL terminal is 24, while only 11 compressor stations is needed from Permian basin to SPL terminal. Details is shown in the SI section S4.

Liquefaction: Most of the processes at the liquefaction facility are powered using NG as fuel except the ship at berth, which is powered by electricity. In both cases of Marcellus and Permian basins, GHG emissions associated with both fuel use and methane leakage are derived from SPL terminal operating data.[20] Detailed emission calculation is shown in the SI section S5.

Shipping: We assume the LNG will be shipped to Asia (China) and Europe (UK), two large gas-consuming markets. GHG emissions during ocean shipping is established based on the marine transportation model developed by Rosselot et al.,[21,48] in which the emissions associated with fuel use are a function of shipping distance, LNG tanker capacity, boil-off generation rate, ratio of methane emissions to boil-off generation rate, and other operational parameters. As an improvement over previous LCA model, our model incorporates the shipping emission data from first measurements on an LNG carrier[49].

Emissions Allocation

GHG emissions must be allocated to all co-products in the O&G supply chain – these include crude oil, lease condensate, processing plant condensate, natural gas liquids (NGLs), and dry gas. These products are generated at different points in the supply chain (crude oil and lease condensate are generated at the upstream site, while processing plant condensate, NGLs, and dry gas are generated at processing plant), thus requiring allocation methods to consider geospatial disparity in co-products. In this study, we employ an energy-based and product-assigned allocation method to allocate emissions to dry gas (raw material for LNG product) and co-products in the upstream and processing stages.

Emissions allocation happens in two stages (Figure S5). The first stage allocation occurs in the upstream, where crude oil, lease condensate, and produced gas are extracted from wells. The produced gas refers to NG that has just been separated from crude oil and undergone deacidification and dehydration process, usually containing some hydrocarbon liquids. The emission at the upstream stage is allocated to all products based on energy content. For some of the processes in the upstream that only deal with produced gas such as gas compression and dehydration, emissions are allocated between dry gas, processing plant condensate, and NGLs. The second allocation stage is completed at processing plant, where the emissions are allocated among dry gas, processing plant condensate, and NGLs. If emissions from a specific process is only associated with dry gas, then all emissions from this process are assigned to dry gas. The energy content is calculated based on the production data and higher heating value for each product. The production data of different types of products in Permian basin are obtained from the Railroad Commission of Texas (RRC) and the New Mexico Oil Conservation Division (NMOCD).[50–52] The production of crude oil, lease condensate and produced gas production in the northeastern Marcellus basin is obtained from Pennsylvania Department of Environmental Protection (DEP).[53] All production data, heating value and calculated energy content for each product are shown in Table S31-S33. Since the data for processing plant condensate and NGLs is not available for northeastern Marcellus, we employ the composition data of produced gas from northeastern Marcellus to estimate the energy content of hydrocarbon liquids from processing plant. [17] Overall, energy-based allocation results in approximately 97% and 31% of emissions allocated to the dry gas stream in the Marcellus and Permian basin, respectively. Details on the emissions allocation are provided in the SI section S8.

Developing measurement informed methane emissions inventory

In our study, we incorporate measurements in upstream, processing, transmission, and shipping to better characterize supply chain emissions. In the upstream and processing stages, we develop measurement informed methane emission estimates to address underestimation of emission in conventional inventory-based inputs to LCAs. In the transmission and shipping stages, measurements are reflected in emission factors.

In the upstream and processing stages, the methane emission rates are obtained from aerial and satellite measurement studies over northeastern Marcellus basin and Permian basin. Not all measurement studies can be directly incorporated into a life-cycle inventory framework. We used the following criteria to select measurement studies: (1) studies should report measured methane emission rate specific to northeastern Marcellus and Permian basins; (2) studies should not exclude emissions from major process stages; (3) studies should report emissions at the site-level to allow for attribution to different stages of the supply chain. The detailed selection of measurement studies is shown in SI S9.

Table 1 shows the measured methane emission rate, measurement informed emission intensity, and corresponding inventory-based emission intensity. The reported methane emission rates in the literature are typically normalized to dry gas production. Because production emissions are associated with co-products, we normalize them to lifecycle stage throughput by multiplying the energy content fraction of dry gas at each stage. Measurement informed methane emission intensities are calculated based on energy normalized methane emission rate, which is obtained from top-down methane measurement campaigns. Then we aggregate all bottom-up methane emission estimates in the process-based life-cycle inventory to calculate the inventory-based methane emission intensities. Finally, we replace bottom-up inventory-based methane emission intensity with measurement informed methane emission intensities.

RESULTS AND DISCUSSION

We first describe the energy flows across the different supply chains considered in this study followed by results from supply-chain specific life cycle GHG emissions. We then quantify the importance of incorporating measurements into LCAs to reflect spatial variation in methane emissions. These results are then compared with other peer-reviewed literature on the LCA of LNG supply chains.

Energy flow along LNG supply chains

Figure 1 shows a Sankey diagram of Marcellus and Permian LNG supply chains across all co-products. Losses and fuel use at each stage are aggregated across the supply chain. For every 1000 kJ of NG delivered, the amount of hydrocarbon extracted in the Permian basin is about 3.2 times higher than that in the Marcellus basin. In the Marcellus basin, the main product is dry gas and only a small amount of processing hydrocarbon liquids (including both processing plant condensate and NGLs) is separated. However, in the Permian basin, the produced gas is co-produced with a significant volume of upstream hydrocarbon liquids (including both crude oil and lease condensate) and processing hydrocarbon liquids. Energy associated with coproducts of upstream hydrocarbon liquids and processing hydrocarbon liquids in the Permian basin represent 55% and 10% of the total energy extracted, respectively. By contrast, energy associated coproducts of processing hydrocarbon liquids in the Marcellus basin represent only 2% of the total energy extracted.

Energy loss from methane emissions includes emissions from flaring, venting, and fugitives at each stage of supply chain, while energy loss from fuel use refers to fuel combustion. For 1MJ LNG delivered to the destination country, the Permian-UK supply chain has higher fuel use related energy loss at upstream and processing stages than that in the Marcellus-UK supply chain, which is associated with a larger volume of fuel gas consumption (lower electrification). In addition, fuel use related energy loss is lower in transmission stage in the Permian basin than the corresponding stages in the Marcellus basin because of the shorter transmission distance between processing plant to liquefaction facility compared to the Marcellus basin.

Methane emissions also vary significantly across these two supply chains. Compared with those in the Marcellus basin, we observe higher methane emission related energy loss from upstream methane emission in the Permian basin. This can be attributed to higher measured methane emissions in the Permian basin. In addition, the energy losses from methane emission in the two basins are significantly lower than corresponding fuel use related losses in the supply chain.

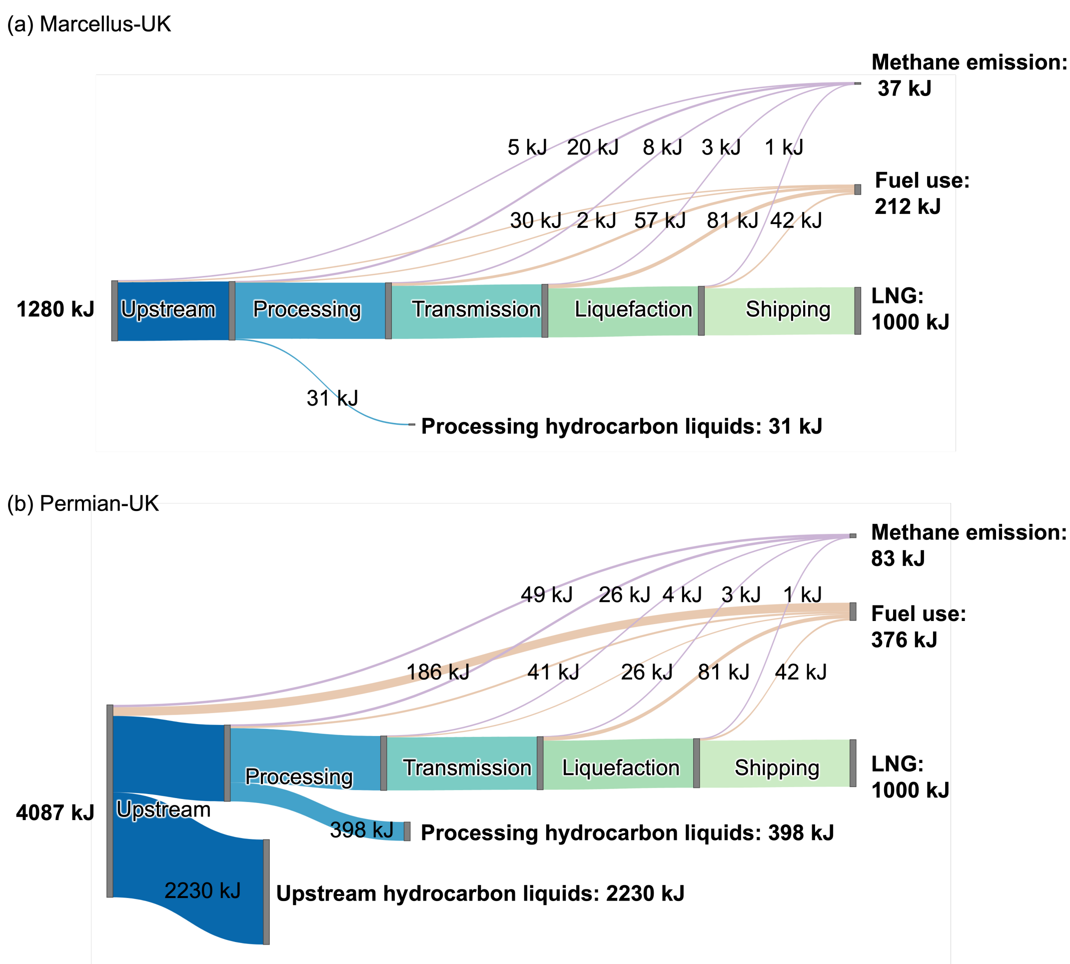

***Figure 1**. Sankey diagram of energy flows associated with the US LNG supply chains to the UK from two production basins. (a) Northeast Marcellus, (b) Permian basin. The two streams above the LNG supply chain represent the energy loss associated with methane emissions (purple) and fuel gas use (orange), while the streams below the LNG supply chain represent the energy associated with NG co-products including upstream hydrocarbon liquids and processing hydrocarbon liquids. The energy content of the hydrocarbons entering the upstream stage for both LNG supply chains are shown at the beginning of the energy flow diagram. For both LNG supply chains, the final product is 1000 kJ of LNG delivered to the destination country at the re-gasification terminal. All energy units are shown in kJ.*

Life Cycle GHG emissions of basin-specific LNG supply chains

Figure 2 shows the life cycle GHG emissions associated with Marcellus and Permian basin NG shipped to UK and China. The contribution from different stages of the supply chain varies considerably between the Marcellus and Permian-sourced LNG. For gas sourced from the Marcellus basin, despite shipping emissions varying with distance, emissions from the upstream, transmission, and liquefaction stages contribute to the majority of LNG supply chain emissions. By contrast, for gas sourced from the Permian basin, the upstream stage contributes up to 49% of total supply chain emissions. Whether the LNG is destined for UK or China, emissions from upstream, processing, and liquefaction are large contributors to total supply chains emissions.

We find significant differences in the life cycle GHG emissions intensity of LNG based on the origin of NG. For LNG deliveries to the UK, the GHG emission difference between the Marcellus and Permian supply chain is 9.3 gCO_2e/MJ, with majority of the disparity occurring in the upstream stage. Thus, LNG delivered to the UK from the Permian basin is 42% more emissions intensive than that from the Marcellus basin. Similarly, the LNG delivered to China from Permian basin is 38% more emission intensive than that from the Marcellus basin.

Difference in methane emissions in the upstream stage is a key driver of the discrepancy in supply-chain GHG emissions, contributing 10.4 gCO_2e/MJ to emission disparity between Marcellus-UK and Permian-UK supply chains. In our model, we calculate the upstream methane emission rate based on recent published measurements. The estimated top-down measured energy normalized methane emission rate from the upstream stage in the Permian basin is 1.10%, which is more than twice the 0.39% in the Marcellus basin (shown in Table 1). The higher value of measurement informed emission in the Permian basin is partly attributable to the extensive flaring activities in that region, which accounts for 12% of total measured methane emissions.[54]

For the processing stage, the GHG emissions in the Permian basin are 1.7 gCO_2/MJ higher than that in the Marcellus basin. This has two proximate causes. First, the degree of electrification in the Marcellus basin is higher compared to the Permian basin which uses NG as fuel for operational needs. This results in a lower emissions intensity in the processing stage for the

Marcellus basin. Second, the higher ratio of processing hydrocarbon liquids to dry gas production in the Permian basin compared to the Marcellus basin also leads to higher emissions.

In the transmission stage, majority of GHG emissions are attributable to fuel gas use at the transmission station and the methane leakage from the transmission station and pipelines. The difference in GHG emissions between two supply chains comes from different amounts of fuel gas consumption and fugitive and venting methane emissions, which is a function of the number and type of transmission stations. With an assumed average distance of 55 miles between compressor stations, the total transportation distance of NG determines the number of transmission stations and therefore, total GHG emissions. In our study, the distance between the processing plant and liquefaction facility in the Marcellus-UK supply chain is 2.2 times that in the Permian-UK supply chain, which thus leads to higher GHG emissions along the Marcellus-UK supply chain.

GHG emissions from the liquefaction stage in the LNG supply chain from the Permian basin are 1.4 CO_2e/MJ higher than that from the Marcellus basin. The different content of the CO_2 in the dry gas is the primary cause of emission disparity between Marcellus-UK and Permian-UK supply chains. The content of CO_2 in Permian gas is up to 2.55%,[20] while there is no CO_2 in the Marcellus gas. Therefore, emissions associated with the removal of CO_2 at the liquefaction terminal in the Permian-UK supply chain is higher than that in the Marcellus-UK supply chain.

Shipping emissions associated with the Marcellus-China supply chain are 3.1 gCO_2e/MJ higher than those of NG shipped to the UK. In addition, we find that the capacity of the ship and the propulsion system type also have a significant influence on the GHG emission of the shipping process, which is in line with recent peer-reviewed literature.[48] The detailed analysis of the effect of the LNG tanker capacity and propulsion system type can be found in SI section S13.

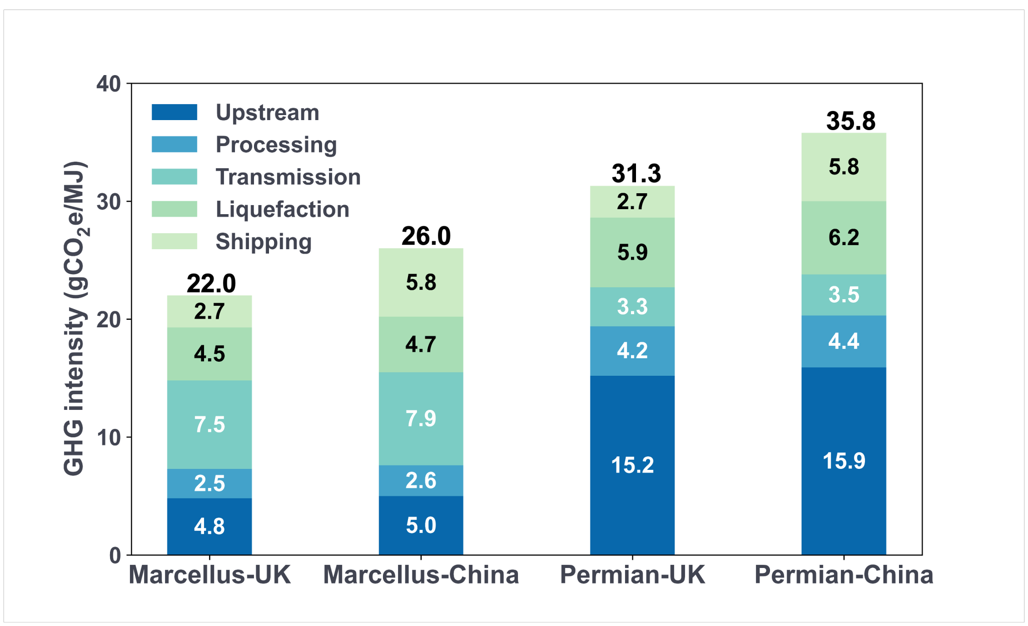

Figure 2*. GHG emissions across each stage of the LNG supply chains using a 100-year GWP. NG in both Marcellus and Permian basins is transported to liquefaction terminals in Louisiana and then shipped to UK or China. The GHG emissions of each stage along LNG supply chains are marked in white and black for visibility, and the total GHG emissions of each supply chain are noted on the top of each column.*

Methane emissions

We use a measurement informed inventory estimate in the upstream and processing stages to better characterize supply chain emissions. Figure 3(a) shows the comparison between an inventory-based and a measurement informed inventory estimate of methane emissions at the upstream and processing stages of the Marcellus-UK and Permian-UK LNG supply chain (SI section S11 for a discussion of the US-China supply chain). In the upstream stage, the emission intensity difference between the Permian-UK and Marcellus-UK supply chains increased from 7.7 gCO_2e/MJ to 10.4 gCO_2e/MJ after incorporating measurements, an increase of 35%. In processing stage, the emission intensity difference between two supply chains is comparable before and after considering measurements. The use of measurement informed emissions inventories helps further differentiate LNG supply chains originating from different basins.

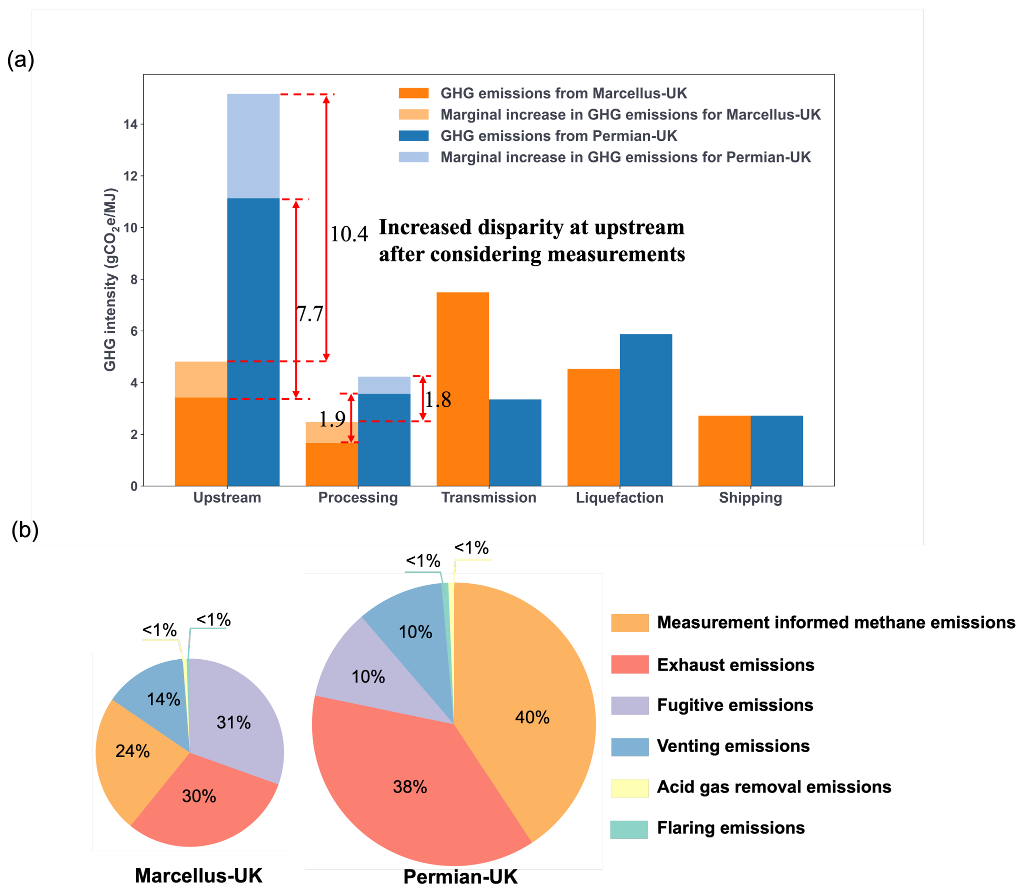

Figure 3*. Impact of measurement informed methane emission on supply chain emissions. (a) GHG emissions of each stage before and after considering measurement informed emissions estimates. The orange and blue bars represent the GHG emissions from Marcellus-UK and Permian-UK supply chains, respectively. The lighter color bars at the upstream and processing stage represent the marginal increase in emission intensity from the use of measurement informed inventories. (b) Contribution from major methane emission source types in the Marcellus-UK and Permian-UK LNG supply chains, respectively. A similar figure for Marcellus-China and Permian-China LNG supply chains is shown in the Figure S6.*

To better understand the importance of developing measurement informed emissions inventories in the context of LCAs, we separate inventory-based emissions estimates from measurement-based emissions estimates. For this analysis, we disaggregated methane emissions into six major categories- five categories based on inventory calculations – fugitive, venting, flaring, exhaust methane emission, emissions from acid gas removal, and one category that encompasses data from measurements – measurement informed methane emissions. Measurement informed methane emissions refer to emissions in the upstream and processing stages that are informed by measurements but not captured by inventory, so there is no double counting between measurement informed methane emissions and other methane emissions based on inventory calculations. The contribution from each category of methane emissions in the Marcellus and Permian basins is shown in Figure 3(b). The area of the pie chart in Figure 3(b) is proportional to the total methane emissions. Whether in Marcellus-UK or Permian-UK supply chain, the contribution of measurement informed methane emissions is significant. The percentage of methane emissions that are not captured by official emissions inventory is up to 40% in Permian-UK supply chain and 31% in the Marcellus-UK supply chain.

Comparison with other literature

Figure 4 compares the results of our model with those of other LNG life cycle GHG emission studies in the literature. In general, the GHG intensity estimation in Abrahams et al.[21] falls between those of the Marcellus-UK and Permian-UK supply chains in this study, while the GHG intensity in Roman-White et al.[20] is lower than both GHG intensity estimates in this study.

In Roman-White et al., NG purchased from several NG suppliers is transmitted to the SPL facility and then shipped to the UK. The upstream emissions in Roman-White et al. are significantly lower than that in our study, being only one-third of the upstream emissions of the Permian-UK supply chain. This upstream emission disparity is associated with different data sources in models. In Roman-White et al., the upstream emission quantification model is based on the weighted supplier-specific emission data reported to EPA GHGRP. However, EPA GHGRP-based emission inventory has been shown to underestimate GHG emissions due to outdated or poorly characterized emission factors.[25] In comparison, the measurement informed emissions estimates used in this work better represent basin-specific emissions that are not captured by the bottom-up inventory. Detailed comparison between Roman-White et al. and this work is described in the SI section S12.

Abrahams et al. takes the processes from production to transmission together and calculated the national-level GHG emissions based on the previous studies of LNG supply chain emissions. The upstream emission is estimated by incorporating data from Weber 2012[55] and assumed a national average methane leakage rate of 3%. In their study, the GHG emissions from the extraction to transmission are 21.3 g CO_2e/MJ, which is 6.5 gCO_2e/MJ higher than that from the Marcellus-UK LNG supply chain and 1.4 gCO2e/MJ lower than that from the Permian-UK. Differences between Abrahams et al. and this study arise from several factors. First, the emission data in Weber's article are more than a decade old and do not include recent advances in measurements. Second, the assumed "most likely" methane leakage rate is employed in their study, which increases the uncertainty of emission estimation. Third, the use of national-level methane emission rate masks the difference in methane emission characteristics between regions. Emissions from the liquefaction stage in Abrahams et al. are 3.2 gCO_2e/MJ, which is smaller than those of two LNG supply chains in our study. This is because the data used in Abrahams et al. comes from peer-reviewed literature published before 2015, prior to the availability of any real-world data on liquefaction terminal emissions in the US.

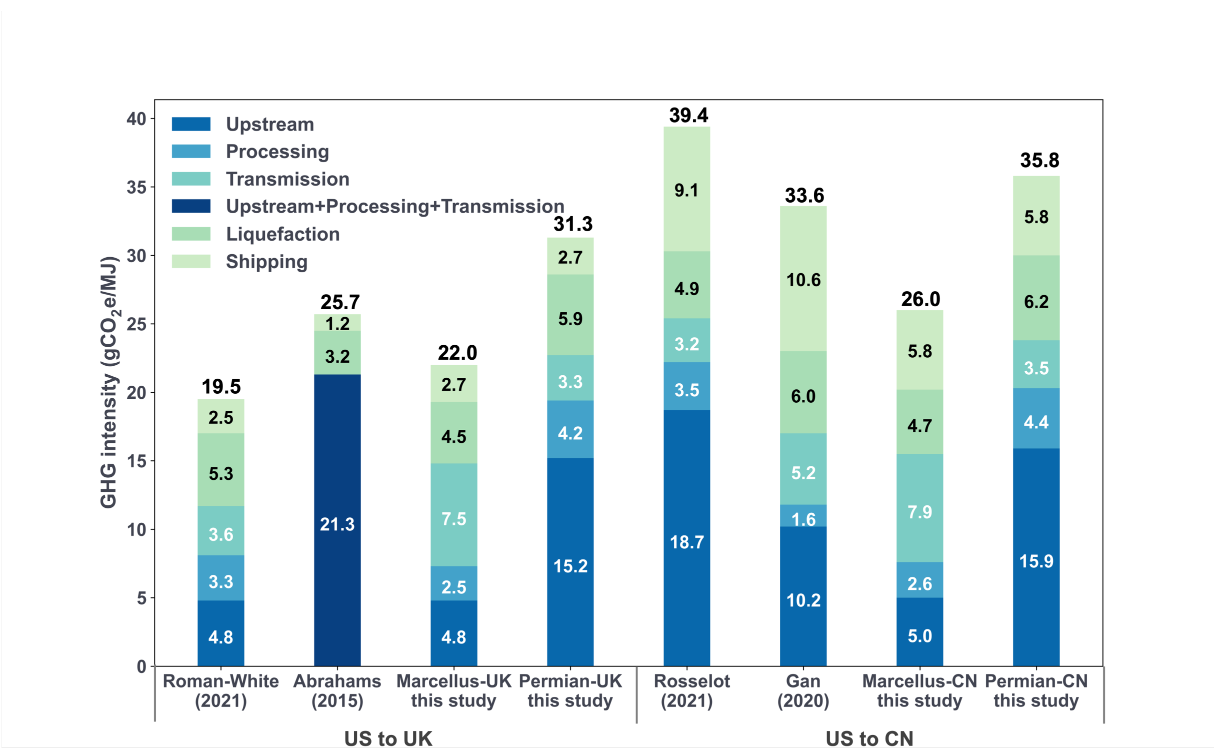

***Figure 4**. GHG emissions intensity comparison in gCO_2e/MJ of US to UK (left) and US to CN (right) LNG supply chains across publicly available life-cycle assessment studies. Results from*

other studies are aggregated based on the life cycle stage boundaries defined in this work.[20,21,42,56]

Similarly, for the US gas to China supply chain study, we compare our study with two recently published studies. The average GHG emissions from US to China in Gan et al.[56] study fall in the range of Marcellus-China and Permian-China in our study, whereas the total GHG emissions in Rosselot et al.[42] are higher than both estimated emissions from Marcellus-China and Permian-China supply chains.

In terms of upstream emissions, Gan et al.'s result fall in the range of estimated emissions from Marcellus-China and Permian-Chain supply chains, because the upstream emission in Gan et al. is an average of 21 US production basins. However, Rosselot et al. estimated GHG emission intensity from upstream of Permian-China supply chain at 18.7 gCO_2e/MJ, which is comparable with 15.9 gCO_2e/MJ of Permian-China supply chain in our study. In Rosselot et al., methane emission at upstream in Permian basin is obtained from TROPOMI satellite data, similar to that in Permian basin in our study. The difference between Rosselot et al. study and our study at upstream emission estimation is caused by different energy losses in subsequent stages after upstream.

The differences between Gan et al. article and our study are reflected in the processing and shipping stages. At processing stage, we use US average processing data from GHGRP supplemented with measurement informed methane emissions, while Gan et al. employed the emission factors and parameters provided by NETL and basin-specific gas composition data. At shipping stage, emissions estimated by Gan et al. is higher than our results. Gan et al. assume that 20% of the boil-off gas is directly emitted into the air, which is higher than the measured percentage of boil-off gas emissions 2.6% employed in our study.

Sensitivity analysis

Figure 5 shows sensitivity analysis for Marcellus-UK and Permian-UK supply chain. Seven parameters are selected for sensitivity analysis, covering all stages along LNG supply chain. The detailed information for parameters selection and range are shown in SI section S13. We made serval critical observations from this figure. For Marcellus-UK supply chain, the parameter with the greatest impact is shipping distance, with the GHG emissions from Marcellus-China 19% higher than that from Marcellus-UK. However, for the Permian-UK supply chain, the different emission allocation method influences most. If all emissions are assigned to natural gas without allocation among co-products, the GHG emissions 49%. Therefore, rational emission allocation is particularly important in the Permian basin.

For both Marcellus-UK and Permian-UK LNG supply chains, the upstream measurement informed emission rate is the second largest influence factor on the total GHG emissions, especially in Permian basin, where upstream measured emission rate varies between Delaware and Midland sub-basins. The emissions in the Delaware basin, where extensive new exploitation has taken place, is larger than that in Midland sub-basin. In addition, the upstream measurement informed emission rate could also vary by using different measurement technologies to detect temporal and spatial upstream emission sources. With more multiscale measurement campaigns conducted and advanced uncertainty analysis method established for measurements, we believe more accurate characterization of upstream measurement informed emission rate could be achieved.

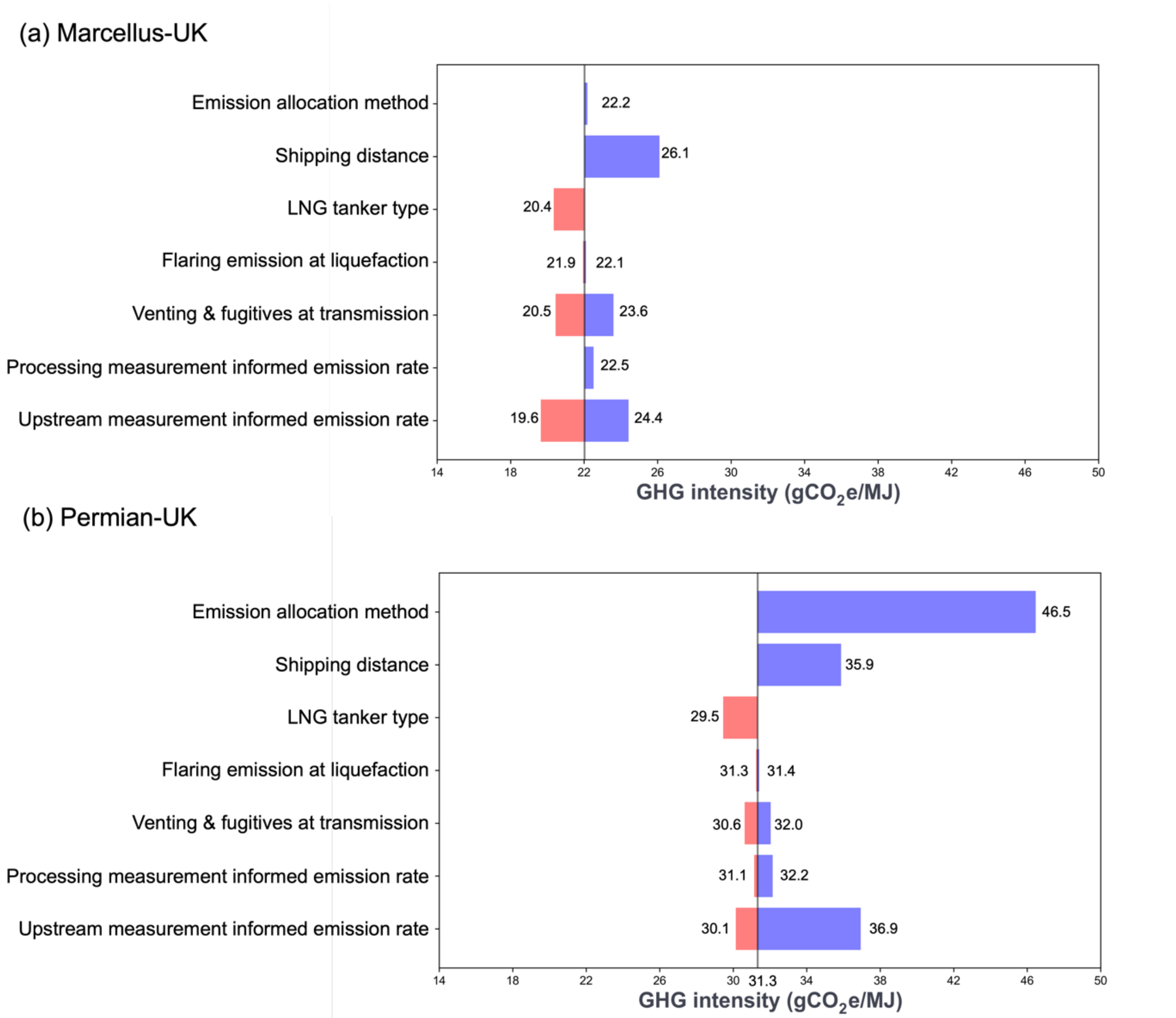

Figure 5. Sensitivity analysis. The solid black lines in this figure indicate the GHG intensity of the base case of 22.0 and 31.3 g CO2e/MJ for (a) Marcellus-UK and (b) Permian-UK LNG supply chains

CONCLUSIONS

Growth in global LNG trade in an increasingly climate-conscious world implies a growing interest in embedded lifecycle GHG emissions of different LNG supply chains. Implementation of a global differentiated gas framework requires accurate and trusted information on supply-chain specific GHG emissions. In this paper, we investigate the geospatial life cycle GHG emissions of US LNG by contrasting gas derived from the Marcellus and Permian basins and delivered to the UK and China. To account for recent studies that demonstrate higher methane emissions from oil and facilities compared to official inventory estimates, we introduce measurement informed emissions in the LCA that supplement inventory-based estimates.

The results show a significant difference in emissions between the Marcellus-UK and Permian basin-UK supply chains, with a difference of 9.3 gCO_2/MJ. Majority of this difference can be attributed to the upstream stage. Critically, the difference between the two supply chains increases with the use of measurement informed emissions estimates, compared to a lifecycle analysis that only uses official emissions inventory as inputs. Thus, accurate differentiation of GHG emissions intensity across LNG supply chains requires the use of measurement data in developing lifecycle emissions inventories.

Further, although the total methane emissions differ between the two basins, the methane emissions that are not captured by the official inventory are both significant. The percentage of methane emissions that are not captured by official emissions inventory is up to 40% in Permian-UK supply chain, higher than that in Marcellus-UK. The majority of the inventory-uncovered emissions comes from the upstream production and gathering and boosting stages. Emission reduction strategies focused on addressing these emissions could significantly reduce LNG supply chain emissions and close the gap between measurements and inventory estimates.

As companies and policymakers develop climate strategies to achieve aggressive carbon reduction targets, it is imperative to accurately characterize the sources and magnitude of emissions across LNG supply chains. The differences in emissions between different LNG supply chains underscore the need to build detailed supply-chain-specific models. While this study used data from publicly available aerial and satellite measurement campaigns to develop measurement informed lifecycle inventories, future developments in technology can further enable effective and accurate differentiation. Satellite technologies with high spatial resolution may enable operator-specific supply chain emissions estimates. The success of a global differentiated gas framework depends on the availability of transparent, timely, and trust emissions data. Recent work by the US Department of Energy and other countries on a shared MMRV framework represents one effective approach in the road to a credible differentiated gas framework.

For the United States, the availability of even higher resolution emissions information will likely enable differentiation for domestic NG markets. Given the size and scale of the US NG ecosystem coupled with the incentives from the Inflation Reduction Act, a robust domestic differentiated gas market could enable rapid reductions in methane emissions, making a significant contribution to achieving 2030 US climate targets of a 50% reduction in carbon emissions.

ASSOCIATED CONTENT

Supporting Information

The Supporting Information is available free of charge.

Model structure; Upstream emission inventory; Processing stage emission inventory; Transmission stage emission inventory; Liquefaction stage emission inventory; Shipping stage emission inventory; Energy flow from upstream through shipping stage; Emission allocation; Summary of measured methane leakage rate; Life cycle GHG emission intensity under 20-year GWP; Methane emission; Comparison with other literature; Sensitivity analysis (PDF)

AUTHOR INFORMATION

Corresponding Author

Arvind P. Ravikumar-Energy Emission Modeling and Data Lab, Department of Petroleum and Geosystems Engineering, The University of Texas at Austin, Texas 78712, United States. Email: Arvind.ravikumar@austin.utexas.edu

Author Contributions

A.P.R. and Y.Z. conceived the study. Y.Z. compiled and verified the data underlying this study and developed the technical model. A.P.R., Y.Z., and D.T.A discussed and interpreted the results. All authors contributed to writing the paper. All authors have given approval to the final version of the manuscript.

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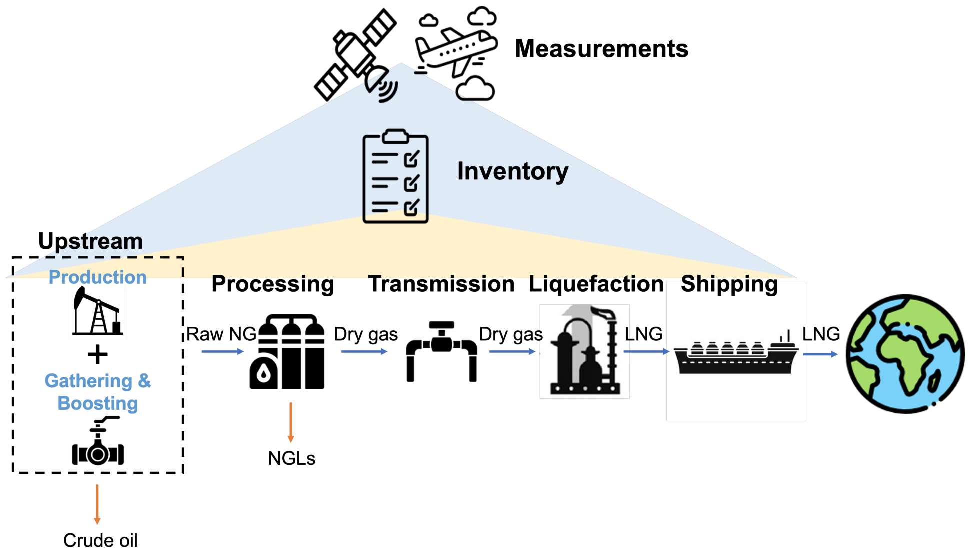
SYNOPSIS

This study develops a geospatial, measurement informed LCA model to examine regional difference in GHG emissions of US LNG supply chains.

GRAPHIC FOR MANUSCRIPT


Measurements
Inventory
Upstream
Production
+
Gathering &
Boosting
Crude oil
Processing
Raw NG
NGLs
Transmission
Dry gas
Liquefaction
Dry gas
Shipping
LNG
LNG