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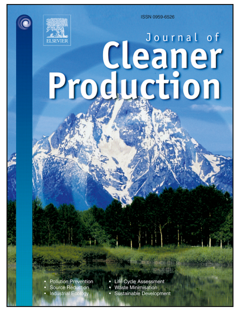

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Greenhouse-gas emissions of Canadian liquefied natural gas for use in China: Comparison and synthesis of three independent life cycle assessments

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Abstract

Liquefied natural gas (LNG) is a promising alternative to coal to mitigate the greenhouse gas (GHG) and particulate emissions from power, industry, and district heating in China. While numerous existing life cycle assessment (LCA) studies estimate the GHG footprint of LNG, large variation exists in these results. Such variability could be caused by differing project designs, system boundaries, modeling methods and data sources. It is not clear which of these factors is most important. Here, three research groups from Canada and the US performed independent LCAs of the same planned LNG supply chain from Canada to China. The teams applied different methods and assumptions but used aligned system boundaries and worked with a single upstream producer to obtain production data. The GHG emissions of Canadian LNG to China for power and heat generation were found to be 427 – 556 g CO_2-eq/kWh and 81 – 92 g CO_2-eq/MJ_{th}. Compared with Chinese coal for power generation, 291 – 687 g CO_2-eq (34% – 62%) reduction can be achieved per kWh of power generated. The central tendency in each study is aligned more closely than the overall uncertainty range: thus, uncertainty caused by fundamental data challenges likely outweighs variability caused by use of different LCA methods. Differences in assumptions and methods among the three teams lead to moderate variation at the stage level, but in better agreement at the life-cycle level, showing the existence of compensating variation. Given the robustness to very different LCA methods, existing literature variation may be explained by project-, location- and operator-dependent parameters.

Keywords: Canadian Liquefied Natural Gas; Greenhouse Gas Emissions; Life Cycle Assessment; Power Generation; District Heating; China

1 Introduction

Global CO_2 emissions increased 1.5% annually during the last decade (2008-2017). China is a major driver of this global trend with an annual increase of 3.0% on average, due primarily to coal consumption (Le Quéré et al., 2018). Coal dominates China's energy use in most of the sectors. For example, the total installed coal power capacity in China reached 900 GW by the end of 2015, accounting for ~59% of the total capacity (China National Development and Reform Commission, 2016). Coal also supplies a large fraction (~80%) of industrial and district heating demands in China (David Benazeraf, 2017; Zhang and Lucia, 2015). Thus, coal consumption, especially in China, has been the focus of global climate policy (Chen et al., 2019).

Given its lower CO_2 emission per unit of energy, natural gas (NG) has been described as a "bridge fuel" to displace coal in the transition towards a low carbon economy (Abrahams et al., 2015; Safaei et al., 2015). According to the BP, gas demand will grow ~50% from 2016 to 2040 and one of the major factors is coal-to-gas switching in China (BP, 2018). The Chinese government has been promoting coal-to-gas switching because of the lower air pollution and greenhouse gas (GHG) emissions associated with NG (Xiao et al., 2016). From 2000 to 2016, China has increased NG production from 24 to 137 billion (10^9) m^3, but domestic gas production failed to keep pace with the increasing demand. To meet this gap, two potential options are coal-based synthetic natural gas and imported natural gas. A study by Kong et al. (2016) suggests that imported natural gas is a better choice in terms of its energy return on investment regardless of whether the environmental inputs are considered. In 2016, China imported 343 billion (10^9) m^3 of liquefied natural gas (LNG), ~10% of global LNG import volumes, with the largest suppliers being Australia and Qatar (China Industry Information Network, 2017). LNG is manufactured by cooling NG to -162 °C, allowing transportation in dense form via ships. Overseas shipping of LNG has the potential to transform gas from a regional resource constrained by pipelines to a global resource with a unified market. The projected growth in China's NG demand has made the Chinese market appealing to international LNG producers.

While switching from coal to gas will clearly improve local air quality (Mao et al., 2005; Nan et al., 2019), the LNG supply chain has environmental impacts: the processes of extraction, transportation and liquefaction of NG are energy-intensive. Methane emissions from NG supply chain could erode some of the climate benefits of NG. Therefore, a life cycle assessment (LCA) to quantify the GHG emissions of importing LNG to China for use is necessary.

Prior LCA studies that quantify GHG emissions of NG and LNG systems show significant variations in estimated pre-combustion emissions (see Supplementary Information (SI) Table S1 for details of these studies). For example, for LNG systems, pre-combustion emissions are found to be 16.3 ± 8.8 g CO_2-eq per MJ of LNG delivered across these studies. These variations can be attributed to differences in projects analyzed, LCA system boundaries, functional units, data sources, modelling approaches, and simplifying assumptions. After end-use, upstream and liquefaction emissions are generally the most significant GHG contributors for NG and LNG pathways. Most data used for modeling upstream emissions in these studies were sourced from government inventories (e.g., US EPA and EIA), and/or peer-reviewed literature, with few studies conducted using data from industry (Gan et al., 2020; Okamura et al., 2007). Similarly, estimates of energy consumption and emissions of liquefaction in existing studies mainly relied on approximate emission factors rather than using industry data or detailed engineering-based process models. Two previous studies (Abrahams et al., 2015; Weber and Clavin, 2012) combined the results from different studies using Monte Carlo simulations. However, they do not isolate the differences in methods and assumptions in a clear manner.

To address some of the discrepancies and uncertainties in existing LNG LCA studies, we assembled three parallel research groups from Stanford University (SU, USA), University of British Columbia (UBC, Canada) and University of Calgary (UC, Canada) to develop independent LCA models of the same proposed LNG project. Each LCA quantifies the GHG emissions of exporting Canadian-sourced LNG to China for power generation and district heating applications. The three independent assessments rely on a few basic assumptions common to all three teams (see Table 2) but used different methods. Data from the collaborating producing company (Seven Generations Energy Ltd., or 7G) were utilized by all three teams for estimating upstream emissions for this study.

2 Description of Case Study

The basic structure of the LNG pathway studied includes 5 stages: (1) upstream: pre-production, extraction, production and processing of NG in the Montney play of Northern Alberta; (2) midstream: transmission of NG to a hypothetical LNG plant in the Prince Rupert area of British Columbia (BC) and subsequent pre-treatment and deep-cut processes to meet the LNG feed specification; (3) liquefaction: conversion of NG to LNG and loading LNG to the marine tanker; (4) transport: including tanker berthing at BC, shipping of LNG to Shenzhen Port, China and re-gasification; (5) downstream: including distribution of NG to a power or district heating plant in Huizhou, China and end use of fuel. The process flow is illustrated in Figure 1.

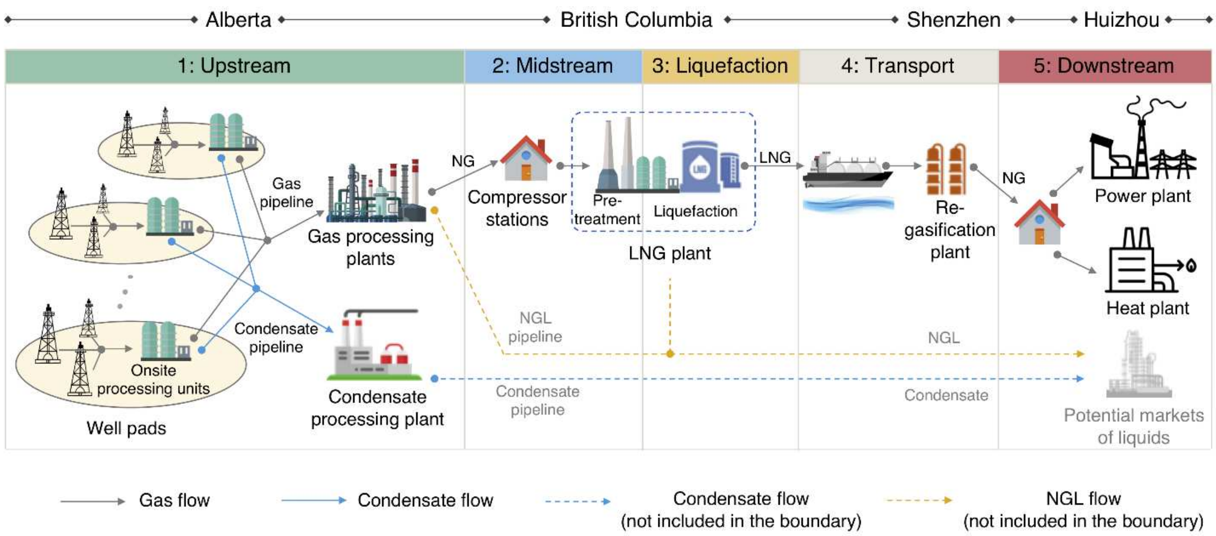

Figure 1. Basic structure of 7G LNG system

A base case system definition and scenario was developed for use by all teams (see Table 2). Emissions are quantified based on LNG feed of 1 billion (10^9) standard cubic feet per day (bcf/d) (defined as the amount of NG ready for liquefaction at the liquefaction facility, after pre-treatment and deep-cut processes). More details on the choice of 1 bcf/d production for the analysis can be found in the Methods section. The project life was assumed to be 30 years, from 2022 to 2052. For each life cycle stage, the GHG sources accounted by all three teams are listed in Table 1. Other GHG sources, such as site exploration, land use change and waste disposal, are considered only by one or two of the three teams and the details can be found in Section 3.1.

Table 1. GHG sources accounted by all three teams for each life cycle stage

Life cycle stage	GHG sources
Stage 1	• Embodied emissions of construction materials, chemicals, fuels and electricity for use in pad development, well drilling and onsite gas processing • Emissions from fuel combustion for providing heat and power • Venting, flaring and fugitive emissions
Stage 2	• Embodied emissions of pipeline material, electricity for compressor station and chemical solvents for gas pretreatment (dehydration, acid gas removal) • Emissions from NG combustion for compressor station • Pipeline fugitive emissions • Emissions from energy consumption (NG) for pre-treatment and deep-cut
Stage 3	• Emissions from energy consumption (NG and/or electricity) for liquefaction
Stage 4	• Embodied emissions of fuels for marine transportation • Emissions from fuel combustion for marine transportation • Emissions from energy consumption (NG) for regasification
Stage 5	• Embodied emissions of pipeline material, electricity for compressor station and power plant infrastructure • Emissions from NG combustion for compressor station • Pipeline fugitive emissions • Emissions from NG combustion emissions for power and heat generation

Upstream production and emission data were provided 7G, based on the Kakwa field in Northern Alberta and the year of 2016. Midstream to downstream data were mainly sourced from the literature as no specific project data are available (see SI Table S2 for details). One team (SU) conducted a field audit of fugitive emissions at 7G facilities associated with the LCA (Javier Roda-Stuart, 2018) and each team requested specific data/information from the company as needed. To account for uncertainties in the system, high and low emission scenarios were also analyzed for various input parameters (see Table 2).

Table 2. Comparison of the base, low and high emission scenarios of LNG for power generation and district heating

	Base scenario	Low emission scenario			High emission scenario		
	(Common to all teams)	SU	UBC	UC	SU	UBC	UC
Stage 1	• Production of 1 bcf/d LNG feed from 2022 to 2052	-	-	-	-	-	-
Stage 2	• Transmission from Kakwa field to BC coast using 8 compressor stations (4 NG powered, 4 electrical) • 30-inch pipeline • Compressor stations spacing 154 km	-	• Low fugitive emission factor (9.22E-07 kg CH_4/kg·km)[a]	• Compressors are entirely powered by electricity • Low fugitive emission factor (4.53E-08 kg CH_4/kg·km)[b]	-	• High fugitive emission factor (5.37E-06 kg CH_4/kg·km)[c]	• Compressors are powered entirely by NG • High fugitive emission factor (2.11E-06 kg CH_4/kg·km)[d]
Stage 3	• NG combined cycle (NGCC) for refrigeration power (54% efficiency) • BC grid for ancillary power	• BC grid for ancillary and refrigeration power	• BC grid for ancillary and refrigeration power	• BC grid for ancillary and refrigeration power	• NG simple cycle (40% efficiency) for ancillary and refrigeration power	• NGCC for ancillary and refrigeration power	• NGCC for ancillary and refrigeration power
Stage 4	• Shipping from BC to Shenzhen via 2.65E+05 m^3 ocean tanker • Boil-off gas (BOG) and additional regasification for propelling power • Return trip using diesel	-	-	-	• Return trip using bunker fuel	• Shipping via 1.40E+05 m^3 ocean tanker	-
Stage 5	• 30 km transmission to power plant or district heating plant • Power generation via NGCC at 54% efficiency • District heating at 85% efficiency	• Power generation via NGCC at 60% efficiency	-	-	• Power generation via NGCC at 49% efficiency	-	-

[a] From Theresa M. Shires et al. (2009), originally 2.24 t CH_4/(km·y), and converted to 9.22E-07 kg CH_4/kg·km by dividing by NG annual transmission; [b] From Skone et al. (2016); [c] From Skone et al. (2011); [d] From Zimmerle et al. (2015)

3 Methods

In 2016, the 7G Kakwa field operations produced a total of 0.291 bcf/d of NG, 39.3 thousand barrels per day (kbbl/d) of condensate and 30 kbbl/d of natural gas liquids (NGLs) (all sales product basis). This total production comes from two separate sources – 7G's legacy plants and 7G contracted third-party plants. Since the emissions data from the third-party plants were not available, we only accounted for the emissions and production associated with 7G's legacy plants and corresponding pads. Production from 7G's legacy plants consists of 0.28 bcf/d NG, 38.3 kbbl/d condensate and 8.31 kbbl/d NGLs. The teams modeled the expansion of production with a target of 1 bcf/d of LNG feed available by 2022, assuming a linear increase from 2016 to 2022 (~4x increase of legacy plant output). This 1 bcf/d LNG feed was modeled to be maintained across the 30-year project life from 2022 to 2052.

The three teams developed their own LCA models to quantify the GHG emissions of Canadian LNG to China for power generation and district heating. The included GHGs are CO_2, CH_4, N_2O and where relevant, HFC-134a. Results are presented as CO_2 equivalent (CO_2-eq), using IPCC AR4 global warming potentials (GWP) with a time horizon of 100 years, i.e., 1, 25, 298 and 1430, respectively (IPCC, 2007). Our functional units are g CO_2-eq/kWh for power generation and g CO_2-eq/MJ_{th} for district heating. The unit of g CO_2-eq/MJ NG was used for comparing pre-combustion emissions. For teams UBC and UC, all thermal energy quantities are measured on a lower heating value (LHV) basis except for energy allocation (see Section 3.3.2), as the heating values of the products (i.e., NG, NGLs and condensate) provided by 7G are in higher heating value (HHV) basis. The team SU used LHV consistently in their modeling.

To maintain independence, initial collaboration between the universities was restricted to broad study outlines and assumptions. After initial results were constructed, the teams engaged in cross-comparison, internal peer review, and error correction to ensure that best practices were incorporated across studies. Differences in modeling methods or assumptions that could not be clearly identified as errors were retained to ensure diversity of methods.

3.1 LCA Models of LNG

Three independent LCA models were developed to quantify the GHG emissions associated with each life cycle stage of the LNG. Features of the model used by each team are shown in Table 3. The differences between results are mainly due to the specific tool used to conduct the LCA as well as different default data employed when 7G data were not available. The processes included by each team in their models and the associated data sources are listed in the SI Table S2. Only SU included the GHG emissions from the NG site exploration operations with data available from their LCA model. Only UBC considered the GHG emissions (or GHG credits) associated with disposal (or recycling) of the waste materials from infrastructure, wastewater from well drilling, waste chemicals and solvents from NG processing, etc., and details can be found in SI Section 4.2.1.6. SU and UBC quantified the land use change emissions based on the same idea, i.e., multiplying the area of land impacted by the carbon emissions per unit of land impacted. Different methods were applied by the two teams to estimate these two elements and details can be found in SI Sections 3.3.1.3 and 4.2.1.1. UC did not consider the land use change emissions as they believed that the existing literature for carbon emissions from land disturbance are not representative of 7G field location and the GHG emissions associated with land use change for NG extraction are typically small compared with other activities over the LNG life cycle. The detailed LCA models of each team are presented in the SI Sections 3, 4 and 5.

SU used the Oil Production Greenhouse Gas Emissions Estimator (OPGEE) model, a peer-reviewed open-source bottom-up oil and gas life-cycle GHG assessment tool (El-Houjeiri et al., 2017). OPGEE estimates the GHG emissions associated with the production, processing, and transmission of oil and gas products. OPGEE was supplemented with custom calculations to model 7G operations more accurately, including 7G internal data on production operations and fugitive emissions data from field leak detection measurement campaigns. Some process stages, such as natural gas liquefaction, are not represented in default OPGEE modules, and so were modeled using data from the literature. For the fugitive emissions from gas extraction and processing, the SU team requested and analyzed quarterly leak detection and repair (LDAR) surveys at 7G production well pads and processing facilities. The SU team also accompanied gas emissions detection contractors on 7G site surveys. The other two teams used the same LDAR data as provided by SU.

UBC developed a custom life cycle inventory of the LNG supply chain. The inventory was developed in a stage-wise manner using a top-down approach. The process flows were determined based on mass and energy balances and the emissions associated with each process were estimated either directly from data provided by 7G or computed using emission factors from published literature. Upstream data were mostly extracted from 7G operation and emission inventory data, while other data, such as infrastructure embodied emissions, pipeline transmission fugitives, energy consumption of liquefaction, marine transportation and regasification were collected from multiple sources including peer-reviewed journal articles, technical reports (see SI Section 2 for detailed data sources for each process) and databases such as GHGenius (Delucchi and Levelton, 2013), EIO-LCA (Carnegie Mellon University Green Design Institute, 2008) and Ecoinvent v3.2 (Wernet et al., 2016), and then compiled in a self-developed Excel spreadsheet. UBC collected the downstream data on regasification of the landed LNG in China and its end use in power generation and district heating and shared with the other two teams.

UC modified life cycle modules developed by the US National Energy Technology Laboratory (NETL) (Skone et al., 2011) that includes default life cycle inventory data for NG production in the US. 7G production and operating data were incorporated to adjust or replace inconsistent assumptions. Some included activity units in the original NETL model, such as gas sweetening, were excluded because the data could not be disaggregated, or the activity was not relevant to 7G operations. To account for aggregated data, some activity units were redefined to match the boundaries of available data. For example, stationary combustion was re-defined to encompass all NG combustion for upstream processing. The modified NETL model was then used to estimate the GHG intensity for each upstream and midstream process. As no actual liquefaction plant exists in Canada, data from journal articles (Abrahams et al., 2015) and environmental impact assessment reports of LNG plants in the west coast of Canada (Environmental Assessment Office of British Columbia, 2015; LNG Canada, 2014) were used to model the NG liquefaction process. UC performed a literature review on liquefaction emissions and shared the results/data with the other two teams.

Table 3. Comparisons of the LCA model of each team

	SU	UBC	UC
Model type	In-house database and LCA simulator (OPGEE)	Built-from-scratch model	Adapted existing life cycle modules from NETL
General approach	Bottom-up approach	Top-down approach	Top-down approach
Uniqueness	• Engineering-based LCA process models • Accurate estimation of fugitive emissions by onsite leak detection surveys • Using current average production per well and decline curve to predict new wells to be drilled	• Detailed emission accounting of life-cycle activities • Analysis of different allocation methods • Using current wells age distribution and decline curve to predict new wells to be drilled	• Monte Carlo simulation to handle uncertainty* • Analysis of different allocation methods • Using current average production per well and decline curve to predict new wells to be drilled

* The details about the Monte Carlo simulation are not presented in this work but can be found in the publication of Liu (2019).

3.2 Production Scale-up

To model production scale-up, each team estimated the number of wells required to be drilled using decline curve to fit reported Kakwa "type curves" (averaged empirical production curves). Each team used different fitting functions to project production over the life of each well and simulation was then used to estimate the number of wells needed (see SI Sections 3.3.1.1, 4.2.1.7 and 5.1.1.4). The number of new wells to be drilled to support such a hypothetical development as estimated by the three teams is shown in Table 4. Infrastructure construction emissions, i.e., pad development and well construction, was estimated based on the new infrastructure to be added, while other emissions associated with gas processing were assumed to scale with production.

Table 4. The number of new wells to be drilled as estimated by three teams

	SU	UBC	UC
Modeling method	Stretched exponential	Exponential	Sum of exponentials
Wells drilled per year during production ramp up (2017 - 2021)	113	118	84
Wells drilled per year during steady state (2022 - 2052)	86	136	84

3.3 Emissions Allocation

3.3.1 Infrastructure Construction Emission Allocation

The time span of the project is 30 years for all teams, while the productive life of wells was assumed by the three teams individually (15 years by UC and 20 years by SU and UBC). New wells and pads will be built over the project timeline to maintain gas production, resulting in residual wells and pads at the end of the project. Infrastructure construction, including pad development, well drilling and completion, is not a part of daily operation, but an event that only occurs one time in the life of a well. SU apportioned the infrastructure emissions proportionally to the amount of condensate being recovered from the well during the design life of the wells. UC evenly apportioned the infrastructure construction emissions throughout the design life of the wells to get an annual emission equivalent. UBC allocated infrastructure emissions based on the average operating time or the average ultimate gas recovery of all operating wells during the project life.

3.3.2 Upstream and Midstream Emissions Allocation

The upstream stage produces NG and other co-products, i.e., condensate and natural gas liquids (NGLs). Emissions from the upstream operations must then be divided between these multiple products. Two types of process-based allocations were examined for the upstream emissions, which are referred to as 1-step and 2-step allocation. The schematics of the two types of process-based allocations are shown in Figure 2. It should be noted that the SU and UC teams adapted 1-step allocation method in their upstream analysis, while the UBC team used 2-step allocation. Prior to liquefaction, NG will go through the pre-treatment to remove impurities (e.g., CO_2 and H_2S, water, and mercury), followed by a deep-cut process to separate heavy hydrocarbons, i.e., liquefied petroleum gas (LPG), from the main stream to meet the LNG feed specification. It should be noted that the deep-cut facilities will only be needed if the gas is too liquid-rich to go directly to the LNG facilities, which is the case in this study. Thus, the allocated emissions from upstream together with the midstream emissions need to be allocated between the LNG feed and LPG. See SI Section 4.2.1.8 for the mathematical representation of the upstream and midstream emission allocation.

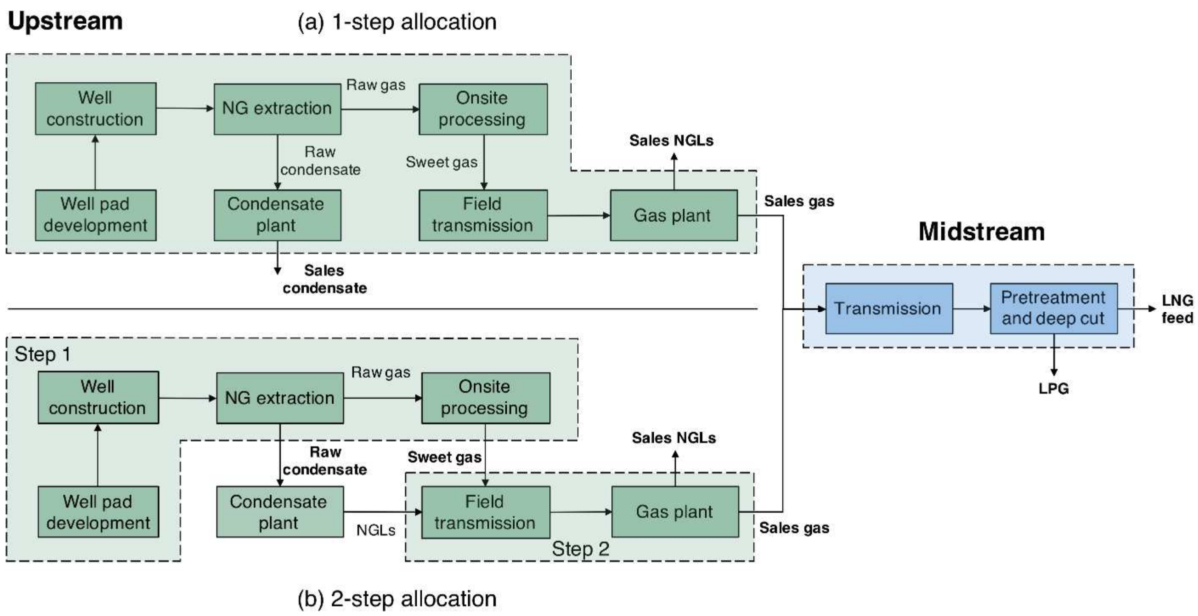

Figure 2. The schematic diagram of upstream and midstream emissions allocation

Different teams made somewhat different assumptions about the energy content of co-products, changes to gas-oil-ratios over time and yields of fractionation processes (see SI Sections 3.2, 4.2.1.8 and 5.1.1.6), which result in somewhat different allocation factors. The allocation factors used by three universities are summarized in Table 5.

Table 5. Upstream and midstream allocation factors used by three universities

1-step allocation (UC and SU)				
Upstream		**Energy-based**	**Value-based**	**Mass-based**
Sales NG		SU: 70%; UC: 55%	UC: 35%	UC: 56%
Sales condensate		SU: 26%; UC: 29%	UC: 60%	UC: 36.5%
Sales NGLs		SU: 4%; UC: 16%	UC: 5%	UC: 7.5%
Midstream		**Energy-based**		
LNG feed		SU: 85%; UC: 85%		
LPG		SU: 15%; UC: 15%		
2-step allocation (UBC)				
Upstream		**Energy-based**	**Value-based**	
Step 1	Sweet NG	65%	35%	
	Raw condensate	34%	65%	
Step 2	Sales NG	90%	89%	

Sales NGLs	10%	11%
Midstream	**Energy-based**	
LNG feed	85%	
LPG	15%	

Note: For energy-based allocation SU allocated 60% for NG for the current 7G operations and allocated 70% for NG for the future operations to account for the expansion of gas production in the future and the increase of the ratio of gas to liquids production over time, while UC and UBC viewed the allocation factor of NG as fixed.

3.4 Power Generation via NG

The efficiency of converting NG to power or heat are key parameters explored in the sensitivity analysis. These parameters can vary from plant to plant, with considerable discrepancy between reported and actual efficiencies and large variation between modern technologies and older plants. In this study, the power generation efficiency of the specific power plant in Shenzhen, China as well as average generation efficiency of China's NG power plants was not available. For this reason, data from operating combined cycle gas turbine (CCGT) plants in the US were collected. Each power plant in the US reports to the US EIA the power generated, volumes of gas consumed, and energy density of consumed gas on a monthly basis (U.S. Energy Information Administration, 2018). SU analyzed EIA reported data for 15 plants of greater than 100 MW capacity with power generation between January 2015 and December 2016 (inclusive). Total generation and consumption for year 2016 were used to compute efficiencies of these modern plants. Mean LHV-basis efficiency is 53.8%, while median is 54.0%, which was used as the best estimate by all three teams in this study. The detailed electricity generation efficiency data can be found in the SI Table S11.

3.5 Uncertainty and Sensitivity Analysis

The three teams used different methods to examine the uncertainty/sensitivity of the key parameters. SU performed a qualitative survey to treat the uncertainty associated with each life cycle stage of the LNG system. UC conducted Monte Carlo simulations to determine the uncertainty of the GHG emission intensities of the LNG, the details of which can be found in the publication of Liu (2019). UC also performed a sensitivity analysis on the upstream and midstream of the LNG by bounding the input parameters using data from 7G and literature or applying a pre-determined percentage variation of the nominal value when these two sources of data were not available. UBC conducted a sensitivity analysis by varying parameters 10% on either side of the base-value over the life cycle of LNG. The Results and Discussion section mainly presents the uncertainty survey by SU and the sensitivity analysis results from UBC with a brief discussion of the sensitivity analysis results from UC. The detailed results of UC's sensitivity analysis can be found in SI Sections 5.1.1.5 and 5.1.2.1.3. The parameters for the sensitivity analysis used by UBC are listed in Table 6.

Table 6. List of parameters for sensitivity analysis by UBC

Parameter	Unit	-10%	Base value	+10%
Project life time	years	27	30	33
Workover emission	Mscf* CH_4/workover	3.30	3.67	4.04
Onsite stationary combustion	t CO_2-eq/y	1.94E+05	2.16E+05	2.37E+05
Sales gas production rate	m^3/y	2.61E+09	2.90E+09	3.19E+09
Canadian transmission pipeline length	km	972	1080	1188
Transmission fugitive emission	t CH_4/km· y	2.012	2.235	2.459
Marine transport distance	km	8864	9849	10834
Liquefaction compression energy	MJ/t LNG	827	919	1011
NG power plant efficiency	%	48.6%	54.0%	59.4%

* Mscf: million standard cubic feet

3.6 LCA model of Chinese Coal for Power Generation

For a consistent comparison of the GHG emissions between Chinese coal and Canadian LNG for power generation in China, a single life cycle model of Chinese coal was built by UBC based on the assumption that the coal is consumed in the same city as NG. Four stages were included in the coal life cycle, i.e., coal mine construction, coal mining (including coal processing), transportation and end use. The coal mine is modeled as in Shanxi Province which is the second largest coal production province in China after 2016. The product is anthracite coal with an LHV of 20.91 MJ/kg. Transportation is by train from Shanxi to Huizhou with a distance of ~2000 km. Four technologies were investigated for coal power generation, which are either the dominant generators in China now or being encouraged to be widely applied in the near future, i.e., (1) integrated gasification combined cycle (IGCC) (600 MW, 44% efficiency); (2) Subcritical coal combustion (300 MW, 38.2% efficiency); (3) Supercritical coal combustion (600 MW, 40.8% efficiency); and (4) Ultra-supercritical coal combustion (1000 MW, 45.19% efficiency). Details of life cycle modeling of coal can be found in SI Section 4.3.

4 Results and Discussion

4.1 Life Cycle GHG Emissions of Canadian LNG

Figure 3 presents stage-wise GHG emissions of LNG for power generation and district heating by the three teams. The main bars present the base scenario GHG emission results, and the error bars indicate the low and high bound of the life cycle emissions estimated by the three teams. The pie charts above the bars show the pre-combustion emission breakdown for the base scenario. The descriptions of base, low and high emission scenarios are shown in Table 2 and the break down GHG emissions data of these three scenarios can be found in the SI Table S92.

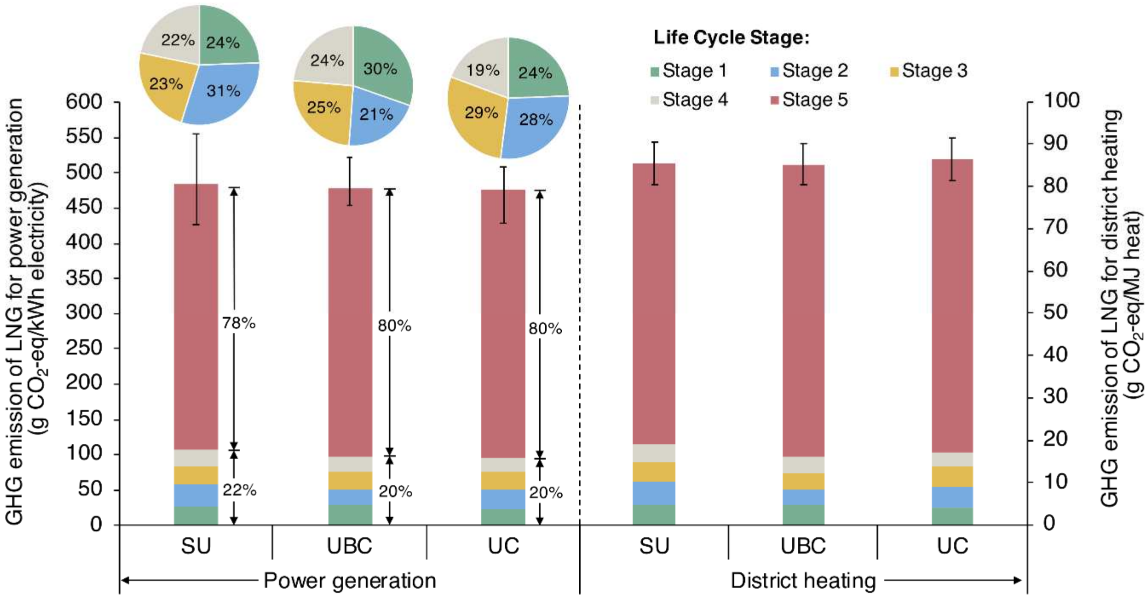

Figure 3. Stage-wise GHG emissions of LNG for power generation and district heating by three teams. Error bars stand for the high and low estimation of total estimated life cycle GHG emissions and the pie charts above the bars represent the LNG pre-combustion (stages 1-4) emission breakdown by life cycle stage for the base scenario; Stage 1: upstream; Stage 2: transmission, pretreatment and deep cut; Stage 3: liquefaction; Stage 4: marine transport and regasification; Stage 5: downstream (see Figure 1)

The life cycle GHG emissions of LNG for power generation and district heating are consistent among three teams although different methods were utilized, ranging from 427–556 g CO_2-eq/kWh [427 (low) – 483 (base) – 556 (high) for SU, 453 – 479 – 522 for UBC, and 428 – 476 – 509 for UC] and 78–92 g CO_2-eq/MJ_{th} [84 (low) – 86 (base) – 87 (high) for SU, 81 – 85 – 92 for UBC, and 78 – 86 – 92 for UC].

In comparison, the life cycle GHG emissions of Chinese coal for power generation were found to be 848 – 1114 g CO_2-eq/kWh (see SI Table S97 for life cycle stage-wise emissions of coal) and 291 – 687 g CO_2-eq (34%–62%) reduction per kWh of power generated is thus achievable in the presented case study. If the 1 bcf/d NG produced in Canada is shipped to China and displaces an equivalent amount of coal for power generation, 14.9 – 35.2 million tonnes (Mt) CO_2-eq/y GHG reduction is possible on a life cycle basis. The most GHG intensive stage in the LNG life cycle is Stage 5, which makes up ~78 – 80% of total GHG emission for both power generation and district heating, while other stages contribute less than 10% individually. This suggests that efforts to reduce end-use emissions or improve end-use efficiency can significantly improve the effectiveness of LNG utilization.

Pre-combustion emissions (Stage 1 to Stage 4) estimates vary by teams (see SI Table S93 to S96). Figure 4 shows a detailed breakdown of Stage 1 emission by three teams, with gas processing identified as the most significant contributor: SU 1.02 g CO_2-eq/MJ (39%), UBC 1.93 g CO_2-eq/MJ (59%) and UC 2.10 g CO_2-eq/MJ (74%). The gas processing emissions are associated with NG combustion to power processes such as solvent regeneration, boiler heating, compression and power generation. It should be noted that SU's processing emissions is only about half of UBC and UCs', which contributes to the major difference in Stage 1 emissions between SU and the other two teams. This can be explained by different methods used by three teams to quantify the gas processing emissions; SU used their in-house LCA software OPGEE with built-in granular process models to estimate emissions from each processing unit, while UBC and UC used the aggregated stationary combustion data provided by 7G to estimate major processing emissions. The aggregated emission data are the combination of emissions from various activities as described above, which are unable to be disaggregated with available data, so detailed unit process comparisons between the three teams cannot be performed in this study.

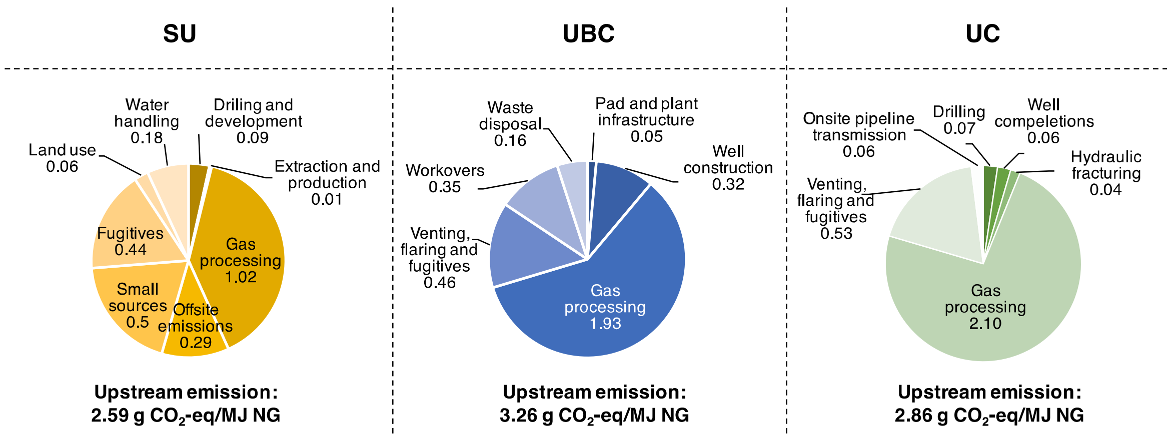

Figure 4. Stage 1 GHG emissions breakdown for three teams (note that (1) the stage 1 emission was allocated based on the energy content of co-products; (2) the unit MJ of NG is assessed at the 7G' field boundary, i.e., before gas entering the transmission pipeline to the liquefaction facility; (3) "Small sources" emission in SU's results is defined as all other sources that are not explicitly modeled by their in-house software OPGEE, e.g., Chemicals embodied emission, indirect consumption by the working labor, maintenance etc.; (4) "Offsite emissions" in SU's results include emissions from the generation of electricity used on-site, and emissions from steel, cement and other materials production for site equipment and wells.)

Venting, flaring and fugitive emissions are another GHG-intensive source of emissions which are in good agreement among the three teams, accounting for 0.44 g CO_2-eq/MJ (17%), 0. 46 g CO_2-eq/MJ (14%) and 0.53 g CO_2-eq/MJ (18%) for SU, UBC and UC. For flaring emissions, all three teams used the data provided by 7G, while for venting and fugitive emissions, SU conducted an onsite survey of 7G field equipment and distributed the data to UBC and UC.

For a consistent comparison of the infrastructure and well construction emissions between three teams, different emission categories were aggregated for each team, i.e., for SU, drilling and development, land use and offsite emissions were combined to obtain 0.44 g CO_2-eq/MJ, for UBC, pad and plant infrastructure and well construction emissions were combined to contribute 0.37 g CO_2-eq/MJ, and for UC, drilling, hydraulic fracturing and well completion emissions were combined to get 0.17 g CO_2-eq/MJ. This indicates that life cycle emissions estimation for LNG are generally not sensitive to infrastructure and well construction emissions.

Each team has some unique emission categories, as shown in Figure 4. For example, SU has a "small sources" category, while the other teams do not, and similarly for UBC's "workovers" category. Small sources emission accounts for a significant portion of SU's upstream emission (~19%) and it is set as a fixed value (0.5 g CO_2-eq/MJ) in OPGEE. This number represents an estimate of the sum of a number of small sources of emission in oil and fields (Masnadi et al., 2018), and it becomes significant in this study as 7G upstream emissions are relatively low. Future work is needed to increase the granularity of the small sources model so that it can be scaled appropriately (i.e., the term can be reduced as more sources are characterized). UBC has a workovers emission of 0.35 g CO_2-eq/MJ, corresponding to fugitive methane emissions associated with workovers. It accounts for 11% of UBC's Stage 1 emissions but it was not included by SU and UC. 7G provided UBC with the number of workovers conducted in its 2016 operation but no emissions data of workovers were audited, so UBC used the emission factor from NETL (3.67 Mscf CH_4/workover) (see Table 5) to estimate the workovers emission.

Since differences in parameters and assumptions used by each team other than allocation methods could also lead to the differences in estimated upstream emissions, for a consistent comparison, the impact of different allocation methods is compared within each team. Results show that allocation drives some of the differences. For base scenario, energy-based allocation leads to nearly twice the upstream GHG emission intensity of value-based allocation, while 1-step and 2-step allocation methods as well as infrastructure emission allocation methods show moderate impact on upstream emissions. More details on the results of different allocation methods on upstream emissions can be found in the SI Section 6.1.2.

For Stage 2 emissions, SU has ~60% and ~25% higher estimate than UBC and UC. Stage 2 emissions are derived from two sources, i.e., (1) transmission emissions, and (2) pretreatment and deep cut emissions. For the pretreatment and deep cut emissions modeling, all three teams used the same energy consumption rate as suggested by 7G (~1.8% of NG input). Also, all teams used identical total transmission distance, the spacing between and number of compressor stations, and the share of NG versus electricity powered compressor stations. Therefore, the differences in Stage 2 emission is attributed to a higher fugitive emission factor used by SU compared with the other two teams. Fugitive emissions associated with pipelines vary widely and different studies report different fugitive emission factors. In this study, SU used emission factor of 3.40 t CH_4/km·y as suggested in IPCC report (Picard, 2001), while UBC and UC used 2.24 t CH_4/km·y based on data from American Petroleum Institute (Theresa M. Shires et al., 2009). The difference in pipeline fugitive emissions factor lead to ~1.5x difference in transmission fugitive emissions between the three teams. Detailed results of Stage 2 for three teams can be found in SI Table S94.

The GHG emission estimates of Stage 3 varied by less than 9% among the three teams for the base scenario (SU: 25.1 g CO_2-eq/kWh; UBC: 24.7 g CO_2-eq/kWh; UC: 24.2 g CO_2-eq/kWh), as they were largely modelled based on the same sources of literature data (Delphi Group, 2013). Stage 4 emissions varied by less than 21% between teams (SU: 23.3 g CO_2-eq/kWh; UBC: 23.1 g CO_2-eq/kWh; UC: 18.3 g CO_2-eq/kWh), mainly driven by different energy consumption rate and the emission factor associated with the regasification process used by each team. Detailed results of Stages 3 and 4 for three teams can be found in the SI Table S95 to Table S96. The main challenges of Stages 3 and 4 assessments are the high uncertainty associated with the energy consumption of liquefaction and regasification processes. Most existing LCA studies as well as this study estimate the energy consumption of liquefaction and regasification based on a rough factor relative to the NG throughput, and do not include detailed modeling. Future work is required to handle these uncertainties by developing process models if no specific plant data are available.

4.2 Comparison with Literature

The estimated GHG emissions of the LNG system in this study are compared with those from the peer-reviewed literature. It should be noted that the end use emission was excluded for the comparison due to its general dominance over the whole life cycle and the uncertainty involved in LNG utilization. The results of our study are from the base scenario. LNG LCA studies (Abrahams et al., 2015; Arteconi et al., 2010; Biswas et al., 2011; Delphi Group, 2013; Jaramillo et al., 2007; Korre et al., 2012; Okamura et al., 2007; PACE, 2009; Safaei et al., 2015; Tagliaferri et al., 2017; Venkatesh et al., 2011) were collected and the following treatments were performed to harmonize the emission data: (1) All results were converted to a basis of MJ of NG delivered to end user. For Delphi Group (Delphi Group, 2013) which ends analysis at the outlet of LNG plant, we converted the results by multiplying by UBC's energy ratio between LNG before marine transport and NG delivered to the end user. (2) All results were converted to LHV basis, for studies using HHV (Arteconi et al., 2010; Jaramillo et al., 2007; Tagliaferri et al., 2017), a factor of 1.1 was applied as suggested by Weber et al. (Weber and Clavin, 2012).

The selected literature evaluate the emissions of LNG projects around the world, while only Delphi Group (Delphi Group, 2013) work is focused on Canadian LNG system. Specifically, it used the upstream emission calculations from GHGenius (Delucchi and Levelton, 2013), which are based on data from two shale gas operations in western Canada, i.e., Montney play and Horn River play. The geological formation, gas characteristics, venting regulation, transmission distance and electricity mix etc., could differ significantly in different regions of the world. Detail analysis of the impact of these location-dependent factors on the results is out of the scope of this study. For a consistent comparison, only the stage-wise results of Delphi Group are presented in Figure 5, with the results of all other LCA studies aggregated and presented in the box plot to show the variation. Detail descriptions of stage-wise emissions of all literature studies can be found in SI Section 6.3.

Stage-wise analysis found large variations in the upstream emissions. Compared with Delphi Group, our upstream emission estimates are 64% lower, which can be explained by the following reasons: (1) lower CO_2 concentration in the raw gas (0.5 mol% for this study vs 1 mol% at Montney play and 12 mol% at Horn River play for the study by Delphi Group); (2) lower venting, flaring and fugitive emissions (~0.5 g CO_2-eq/MJ for this study vs ~1.6 g CO_2-eq/MJ for the study by Delphi Group), as 7G tries to reduce methane emissions by, e.g., using instrument air instead of instrument gas pneumatic devices and conducting regular leak detection and repair surveys.; (3) lower production and processing emission (~1.7 g CO_2-eq/MJ for this study vs ~3 g CO_2-eq/MJ for the study by Delphi Group), as relatively new facility in operation and dual fuel (diesel and NG) are used for well drilling and completion operations to increase the energy efficiency.

Compared with the total pre-combustion emissions of LNG from literature, 16.3 (median) ± 8.8 (standard deviation) g CO_2-eq/MJ (including both Delphi Group and other studies), the result of this study, 14.7 (median) ± 1.0 (standard deviation) g CO_2-eq/MJ (combination of the results from three teams), shows ~10% less emissions in terms of the median value and significantly lower variations. Three independent groups used the same verified data from industry together with data from engineering studies and literature, which enhances the robustness and reliability of the results. This may also imply that the differences in methods and assumptions would create less variations for the LNG pre-combustion emissions for a clearly defined case, while much larger variations could be caused by location dependent parameters like gas characteristics, electricity mix, transmission distances, etc., as well as operation dependent parameters like facility energy efficiency, processing technologies, leak detection and repair behavior, etc. To verify this statement, future work needs to be done by feeding the literature models with our data to see whether it will make a big difference on the emission estimates.

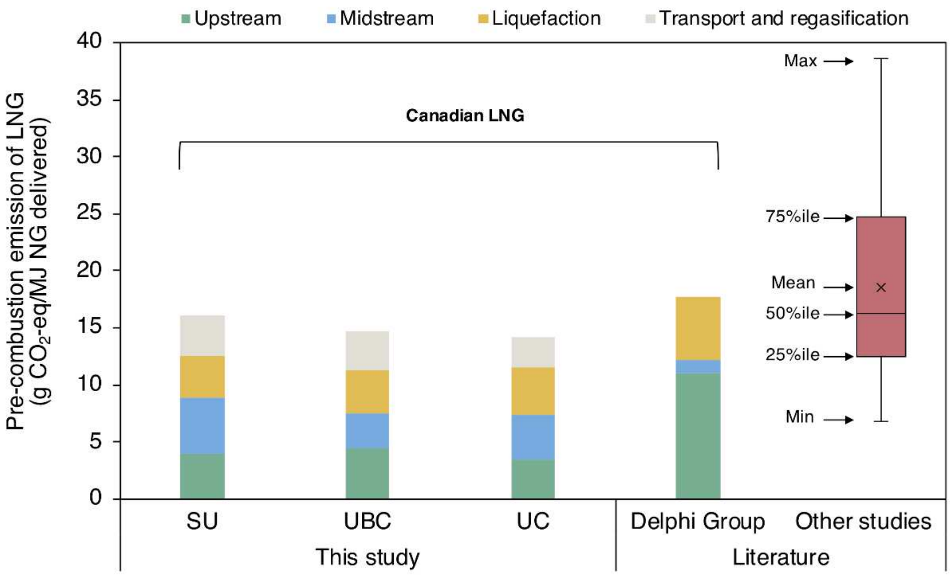

Figure 5. Comparison of the pre-combustion emission of LNG between this study and literature (Note that (1) the box plot shown here representing the total pre-combustion emissions from literature studies except Delphi Group; (2) Delphi Group's result was originally reported in MJ of NG out of LNG plant, and a factor of 1.05 was applied to account for the consumption and loss during marine transportation, regasification and distribution to make their result comparable; (3) Delphi Group's results show the average emissions of Montney play and Horn River play operations.)

4.3 Uncertainty and Sensitivity Analysis

SU conducted a qualitative survey of the uncertainty for each life cycle stage of the LNG system and the results are shown in Table 7. End use emissions dominate the life cycle emissions, so decreasing uncertainty in this stage is the best way to reduce overall uncertainty. Studies attempting to better understand the end use of LNG in China are useful for determining the real-world GHG emissions of Canadian-produced LNG. Large uncertainty is also found in liquefaction and regasification. Different technologies and energy sources can make a big difference on the energy consumption and subsequently GHG emissions. Process models of the liquefaction and re-gasification processes would contribute greatly to the academic literature. Although using 7G's data reduces the uncertainty, the upstream emissions are still pale in comparison to the total emissions from other stages. Time may be better spent on modeling other processes in the LNG supply chain, if the goal is to best estimate life-cycle emissions (Javier

Roda-Stuart, 2018).

Table 7. A qualitative survey of uncertainty for each life cycle stage of the LNG system by SU

Stage	Uncertainty Level	Description
Upstream	Medium	Access to detailed data on 7G operations, site visits with real measurements, and significant time spent modeling upstream processes. Intermittent emission sources* are not included, increasing the uncertainty level from low to medium.
Midstream	Low	Transmission energy requirements are well-understood, and sources of emissions fairly limited.
Liquefaction	High	Many unknowns here and significant differences between what has been reported in environmental impact assessments and what has been modeled and reported in academia.
Transport	Medium	Tanker shipping emissions are well understood (low), but re-gasification remains under-studied and is not modeled in depth in this study (high).
Downstream	High	Power generation and district heating emissions are well-understood, but significant uncertainty remains in determining exact end-use of LNG in China.

* Intermittent emission sources include intermittent venting or site changes. For example. catadyne heaters are seasonal pieces of equipment that are used to maintain a certain temperature near temperature-sensitive equipment. They are only utilized during cold weather events and could emit large amounts of gas through poor combustion.

Ten parameters were tested for their sensitivity to the life cycle GHG emissions of LNG for power generation by UBC (the specific values of corresponding parameters can be found in Table 6) based on time-based 2-step energy allocation (see Section 3.3.1, Section 3.3.2 and SI Section 4.2.1.8 for details about the allocation methods). Figure 6 shows the variation of results subject to ±10% change in each parameter. The most sensitive factor is associated with end use, which is the NG to power efficiency. This was expected as the end use stage accounts for about 80% of the life cycle GHG emission of LNG for power. Sales gas production rate and liquefaction energy requirement rank the second most sensitive parameters. These two parameters lead to a 0.5% change of the life cycle GHG emission if the nominal values are changed by 10%. This impact is moderate when compared with the influence of NG power plant efficiency. Other parameters, such as onsite combustion emission, project lifetime, workover emission factor and etc., show only minor impact (<0.4% variation). In terms of the upstream and midstream of LNG, gas production rate, NG consumption for stationary combustion in gas processing, onsite venting and flaring emissions, and NG consumption by compressor stations are among top sensitive parameters according to the analysis by UC (see Figure S24 and Figure S25 of the SI).

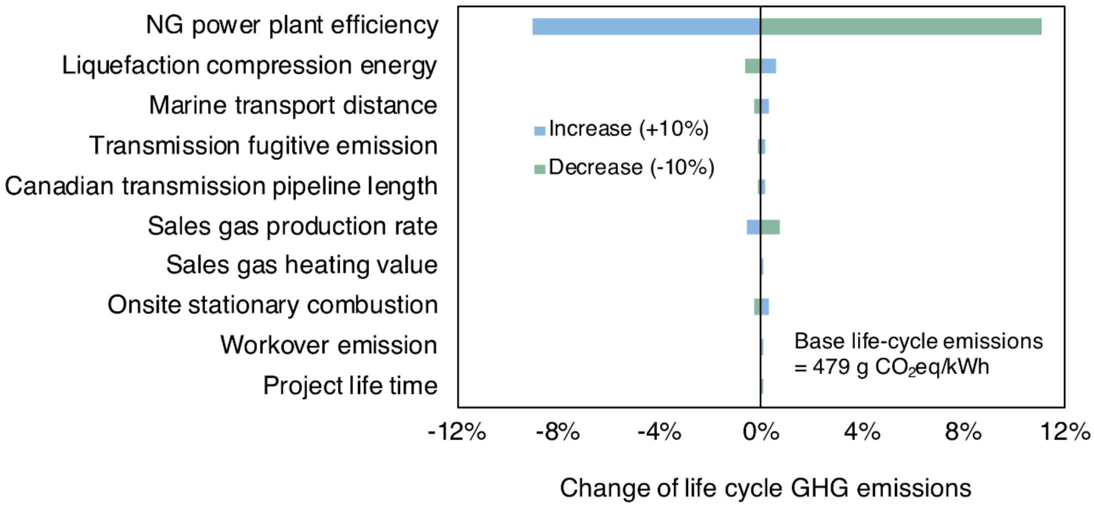

Figure 6. Sensitivity analysis of the GHG emissions of LNG for power generation

5 Conclusion

This study presented three independent LCAs with comprehensive analysis and consistent comparisons on the GHG emissions of a planned LNG supply chain from Canada to China. The key issue addressed here is the potential uncertainty in LCA studies performed by different teams using different methods. Compared with the current literature, our results show significantly lower variations (standard deviation: 1.0 vs 8.8 g CO_2-eq/MJ) in LNG pre-combustion emissions. This could imply that (1) using the same verified data from industry together with data from engineering studies and literature can enhance the robustness of the results; (2) differences in methods and assumptions by qualified teams would not give substantially different life-cycle results for a clearly defined case, while much larger variations could be caused by location and operation dependent parameters such as gas characteristics, electricity source mix, processing technologies and the leak detection and repair (LDAR) program deployed. The second point still needs to be verified in the future by feeding the literature models with our data to see if it will make a big difference on the emissions estimates.

Compared with Chinese coal for power generation, a reduction in emissions of 34% to 62% (291–687 g CO_2-eq per kWh) can be achieved using LNG from Canada. The end use of the re-gasified LNG contributes ~80% of total emissions over the life cycle, while other pre-combustion stages contributed less than 10% individually. Gas processing is the largest contributor to the upstream emissions of LNG, followed by venting, flaring and fugitives. The pre-combustion emissions estimated in this study are lower than the median of literature studies (14.7 vs 16.3 g CO_2-eq/MJ) due to the characteristics of the gas, relatively new upstream facilities operating in a highly regulated jurisdiction and effective methane mitigation practices deployed by the operator. Therefore, the upstream emission (stage 1) results of this study may not be representative of current but possibly future operator behavior and natural gas production in Canada. As fugitive emissions reduction regulations become more stringent, the emissions rates seen here will likely become more common.

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Highlights

- Three independent LCAs on the same LNG system using different methods and assumptions
- Large GHGs mitigation by displacing Chinese coal with Canadian LNG for power/heat generation
- Methods variation has less impact on life-cycle results than location- and operation-dependent factors
- Using both industrial and literature data can enhance the robustness of the life-cycle results

Declaration of interests

☒ The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

☐The authors declare the following financial interests/personal relationships which may be considered as potential competing interests: