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Policy Analysis

Greenhouse Gas Emissions of Western Canadian Natural Gas: Proposed Emissions Tracking for Life Cycle Modeling

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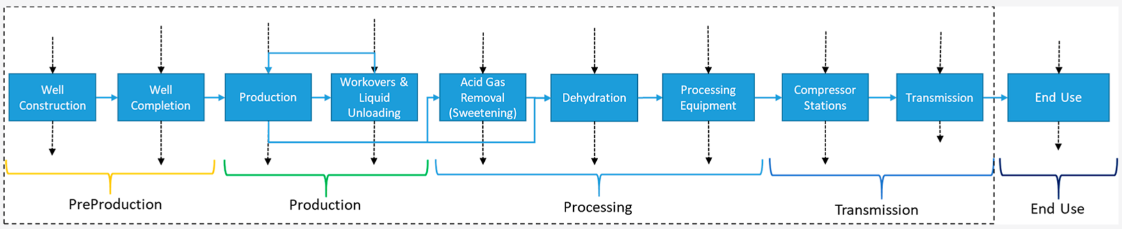

ABSTRACT: Natural gas (NG) produced in Western Canada is a major and growing source of Canada's energy and greenhouse gas (GHG) emissions portfolio. Despite recent progress, there is still only limited understanding of the sources and drivers of Western Canadian greenhouse gas (GHG) emissions. We conduct a case study of a production facility based on Seven Generation Energy Ltd.'s Western Canadian operations and an upstream NG emissions intensity model. The case study upstream emissions intensity is estimated to be 3.1−4.0 gCO_2e/MJ NG compared to current best estimates of British Columbia (BC) emissions intensities of 6.2−12 gCO_2e/MJ NG and a US average estimate of 15 gCO_2e/MJ. The analysis reveals that compared to US studies, public GHG emissions data for Western Canada is insufficient as current public data satisfies only 50% of typical LCA model inputs. Company provided data closes most of these gaps (~80% of the model inputs). We recommend more detailed data collection and presentation of government reported data such as a breakdown of vented and fugitive methane emissions by source. We propose a data collection template to facilitate improved GHG emissions intensity estimates and insight about potential mitigation strategies.

KEYWORDS: *life cycle assessment, natural gas, greenhouse gas emissions, environmental policy, oil and gas*

■ INTRODUCTION

Canada is the world's fourth largest producer of natural gas (NG), producing 444 million cubic meters per day in 2016.[1] The NG industry in Canada is expected to grow ~10% by 2040 as demand increases locally and globally. This demand is likely to be met from increasing shale and tight gas production in Western Canada as production from conventional methods decline.[2] At the same time, oversupply of NG in North America is creating economic challenges.[3] In addition, commitments by Canada, the United States (US), and Mexico to reduce methane emissions by 40−45% below 2012 levels and various climate commitments provide additional challenges.[4,5] Drivers of current greenhouse gas (GHG) emissions in Alberta (AB) and British Columbia (BC) from the NG industry are poorly understood,[6] and reported data are insufficient to inform policy and target emissions reduction. For example, it has been argued that reported methane emissions are potentially being underestimated.[7−9] Despite these insufficiencies, it is important to understand the current state of GHG emissions in the NG industry across the entire life cycle, the drivers of GHG emissions, and opportunities for mitigation as well as their relative effectiveness.

Life cycle analysis (LCA) is a quantitative tool used to estimate the environmental impacts from a product or process over its lifetime and supply chain from the initial extraction of materials through use to disposal of unwanted residuals (i.e., cradle to grave).[10] In recent years, a number of LCAs focused on US-produced natural gas[11−18] have estimated the GHG emissions associated with unconventional gas production. These studies primarily used field specific data for upstream activities, whereas downstream emission estimates from pipelines and end uses are typically generic representations.

Only a few LCAs have been performed on Canadian NG,[6,19−25] all of which rely on US data to fill in data gaps. While lack of geographically specific data on transmission and end use is an issue for future research, this paper focuses on improving the data collection process for field specific upstream data in Western Canada for NG production.

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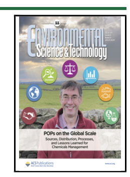

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Public data sets for GHG emissions in AB and BC suffer from data aggregation. This allows the information to be easily processed but does not provide insight into the drivers of emissions nor mitigation opportunities. This paper presents a gap analysis in currently available public data and assesses where further data reporting could improve the GHG emissions assessment of the upstream stages of the NG life cycle. In this study, we define upstream stages to include the operations taken from the drilling of the NG wells through to treatment and transmission of the NG. The use and value of such data are demonstrated through a case study using data from Seven Generations Energy Ltd. (hereafter referred to as "company") NG operations in the Kakwa area of Grande Prairie, AB. The company is a midsized operator in Alberta and produced 291 MMscf/d in 2016[26] compared with approximately 15.5 bcf/d produced in Canada in 2016 (1.8−1.9% of Canadian production). Through the gap analysis and case study, we propose a common data template to reduce gaps in emissions data collection by recommending changes to the current reporting structure that, if adopted, can aid in improved accuracy, specificity, and use of future NG LCA studies. This study's estimates have been included in two other studies (Roda-Stuart[27] and Nie et al.[22]) for the purposes of assessing the potential impacts from a LNG project. However, the investigation of the data inputs available in the public domain have never been compared with those of company specific data.

■ LITERATURE REVIEW

Several studies[6,19−25] estimate upstream emissions intensities of BC and AB NG activity. The case study builds on these to determine what data is missing or requires disaggregation to better understand the sources and drivers of GHG emissions of Western Canadian NG. Senobari[6] and Manouchehrinia et al.[25] use a top-down approach to estimate an emissions intensity for all BC NG production using publicly available data from the BC government.[28] The top-down approach uses reported emissions data sets to estimate the upstream emissions intensity. The bottom-up approach estimates emissions from each piece of equipment/process included in the upstream to estimate an emissions intensity. The top-down approach from these two studies results in emissions intensities of 6.4 and 6.4−6.8 gCO_2e/MJ NG at a transmission pipeline outlet, respectively. Senobari[6] also compares these top-down emissions intensities with a bottom-up approach using basin and well properties for specific basins and data from US literature[13,29,30] to fill in data gaps. The bottom-up emissions intensity estimates for the Montney basin and conventional production are 6.7 and 6.2 gCO_2e/MJ NG, respectively, and are comparable to the 6.4 gCO_2e/MJ NG estimated using the top-down approach. GHGenius,[20] a Canada-based open source LCA model, estimates emissions using data available from the Canadian Association of Petroleum Producers and the US Environmental Protection Agency (EPA) along with specific assumptions on activity factors in the production and processing phase of the supply chain. Coleman et al.[21] estimate potential emissions for upstream stages to LNG exports including estimates for BC and AB derived from available public data.[28,31] Raj et al.[19] provide an estimate using a bottom-up approach for BC production basins using basin properties,[32] BC production data,[32] and US literature.[33] Nie et al.[22] use results from three LCAs (one of which is presented in this paper) to estimate life cycle emissions from western Canadian NG supplied to China as LNG. Three other recent studies[7−9] assess upstream methane emissions from AB and BC oil and gas operations and conclude that reported values underrepresent actual emissions. Generally, the literature described in this paragraph does not allow for the investigation of the drivers and sources of variability in GHG emissions due to aggregated regional emissions data and reliance on US literature.

Several studies investigate the life cycle GHG emission intensities of US NG operations. Estimated upstream emission intensities range from 8 to 22 gCO_2e/MJ NG depending on production activities and reservoir characteristics. Jiang et al.,[12] Laurenzi et al.,[15] and Mallapragada et al.[17] estimate upstream emissions for shale gas from the Marcellus region at 13, 15, and 14 gCO_2e/MJ, respectively. Skone et al.[13] of the National Energy and Technology Laboratory (NETL) estimate upstream emissions for gas from multiple regions across the US including Barnett and Marcellus formations ranging from 8 to 23 gCO_2e/MJ. Weber and Clavin[11] collect estimates from six previous studies across different formations to explore the causes of differences presented and propose a "best" estimate of ∼14 gCO_2e/MJ. Burnham et al.[14] and Stephenson et al.[16] estimate emissions for average US NG to be 14 and 8.3 gCO_2e/MJ using two independent methods. Recent research and data collection campaigns[29,30,42,43,34−41] show that component-level measurements tend to underestimate emissions, as they are not well suited to capture intermittent or episodic emissions.[44] These studies show that current methane emissions estimates established by the EPA are incomplete. While the literature on US is extensive, it is not directly applicable to emissions estimates from NG activities in western Canada due to differences in production methods, flaring and venting regulations, and basin properties. Even within Western Canada there are differences in regulations. For example, flaring limits in AB for large gas plants is 5 million m^3 per year,[45] whereas BC has a flaring conservation flowchart and penalties for flaring above 900 m^3 per day[46] (∼330 000 m^3 per year if flaring is constant). As such, further work is required to identify data needs to explore the drivers and sources of variability in GHG emissions associated with western Canadian NG production.

■ METHODS

The objective of this analysis is to identify current data gaps and data aggregation that exist in AB and BC public databases. Data gaps include GHG emissions or operating characteristics (e.g., flaring efficiency) that are not available publicly. We then compare estimates using public data to company operating data to determine if these data gaps can be reduced or eliminated. We explore opportunities to improve data quality and provide the detail required to investigate the drivers of emissions and the nature and magnitude of variability in upstream emissions to inform LCA.

Two activities are undertaken to achieve this goal:

1. A case study is performed to estimate the company's emissions intensity using company operating data. These results are then compared to upstream GHG emissions from previous studies of Western Canadian and US NG LCAs. A sensitivity analysis and Monte Carlo simulation are conducted to determine the drivers and variability of emissions, respectively. This includes assessing the impact of different product allocation methods.

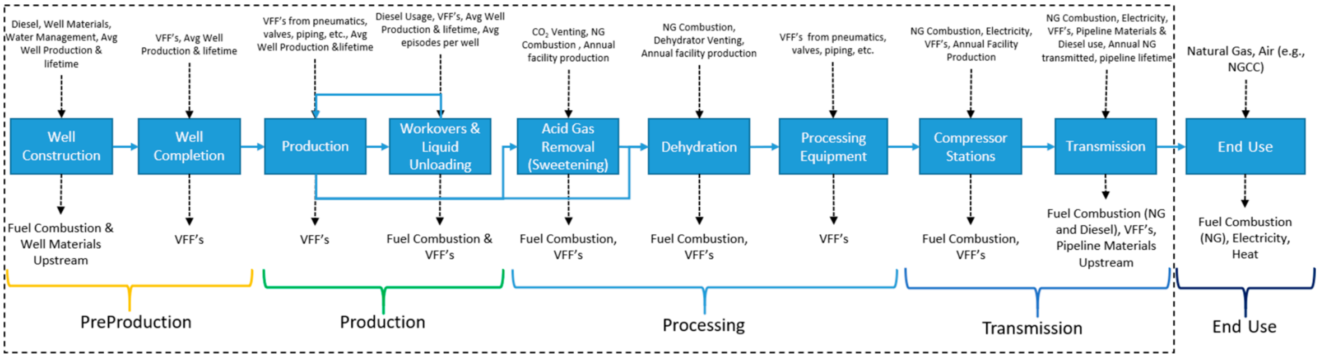

Figure 1. Life cycle of natural gas considered in this study. The boundaries for upstream NG emissions intensity assessment are shown as a dotted box—end use emissions are not included in this calculation.

2. Data gaps that exist between company operating data, public AB and BC data, and US data are identified to explain the drivers of emissions derived from company provided data beyond what is possible using publicly available data. An alternative data template for GHG emissions reporting is proposed to improve data collection beyond current public data sets. This data template will add a level of detail over and above what is currently publicly presented based on government reporting regulations. The characteristics of additional data and the level of effort required to collect it are also discussed.

Emissions Intensity Estimates: Company Case Study. Company operating data from 2016 associated with preproduction, production, and processing are input into a compiled set of activity units from Skone et al.,[13] referred to hereafter as the "NETL model". The NETL model was modified to accommodate the data provided by the company. For example, in some cases, company data are more aggregated than the NETL model inputs, requiring some aggregation of model activity units. The details of model adjustments are described in section S.3 of the Supporting Information. Figure 1 presents the life cycle of NG with the four processes included as upstream NG production considered in this analysis outlined in the dashed box: preproduction, production, processing, and transmission. It is noted that we refer to upstream as anything that occurs prior to end use, which industry typically defines as upstream and midstream activities.

The following are key assumptions made in the model:

- Flaring efficiency: 98%[47]
- Fuel emission factors are based on default values in the NETL model[13,47]
- Average NG well production based on company operating data in 2016[48]
- 365 days/year operation
- Lower heating values (LHVs) used to represent NG energy content[48]

We also conduct a sensitivity analysis to assess the relative impact of data inputs and model parameters on emissions intensity estimates. Company provided data and model assumptions are included in this sensitivity analysis. Company and publicly available data are used to determine sensitivity ranges whenever available. When data are not available, each parameter was varied by ±50%. The full list of parameters tested and their sensitivity range are presented in section S.6 of the Supporting Information. Fuel emissions factors were not tested in the sensitivity analysis as they are not expected to vary significantly (<3%).[12] For example, an ~3% fuel emission factor change would result in an ~1−2% change in the NG emissions intensity depending on the ratio of emissions from combustion and other sources. We also use Monte Carlo (MC) simulations to determine the uncertainty in the GHG emissions intensity estimates. The parameters that are includedn and results of the Monte Carlo simulation are included in Figures S.3−S6 and Table S.6 in the Supporting Information.

Various allocation methods[49] have been deployed to attribute total GHG emissions to individual products. In this case study, emissions allocation is an important consideration as the company produces condensate and NG liquids (NGLs) in addition to NG at each well. We analyze four allocation methods in this study—energy-based, financial-based, mass-based, and displacement-based—to attribute upstream emissions to each product (excluding transmission). The calculation and description of each allocation method can be found in section S.6 of the Supporting Information.

Identification of Data Gaps and Proposed Data Collection Template. There is significant variation in the level of detail used to represent upstream NG activities in the company case study, public western Canadian data sets, and US EPA. In this step, the data gaps are compared and ranked based on their importance in estimating an emissions intensity informed by the company case study sensitivity analysis and MC simulations. The identification and analysis of these data gaps are detailed in section S.4 of the Supporting Information.

All data parameters from the NETL model are assessed and assigned a numerical tier from 1−3 based on its importance. Tier 1 data parameters include data required to estimate important GHG emissions (e.g., diesel use) and those that affect the upstream emissions intensity by at least 0.1 gCO_2e/MJ NG determined using the sensitivity analysis. Tier 1 data parameters are necessary in estimating an emissions intensity for their respective activity and process. Tier 2 data parameters affect the emissions intensity calculation as well but to a lesser degree (<0.1 gCO_2e/MJ from sensitivity analysis) than tier 1 parameters. Tier 2 parameters aid in refining the accuracy of the emissions intensity estimate. For example, flaring efficiency is a tier 2 data parameter since changing it would affect emissions from flaring but not over the 0.1 gCO_2e/MJ (~1−4%) change needed for tier 1, thus affecting the accuracy of the estimate but not the order of magnitude. Tier 3 parameters provide detailed information that is not vital to determining emission factors or sources but would be useful to study other

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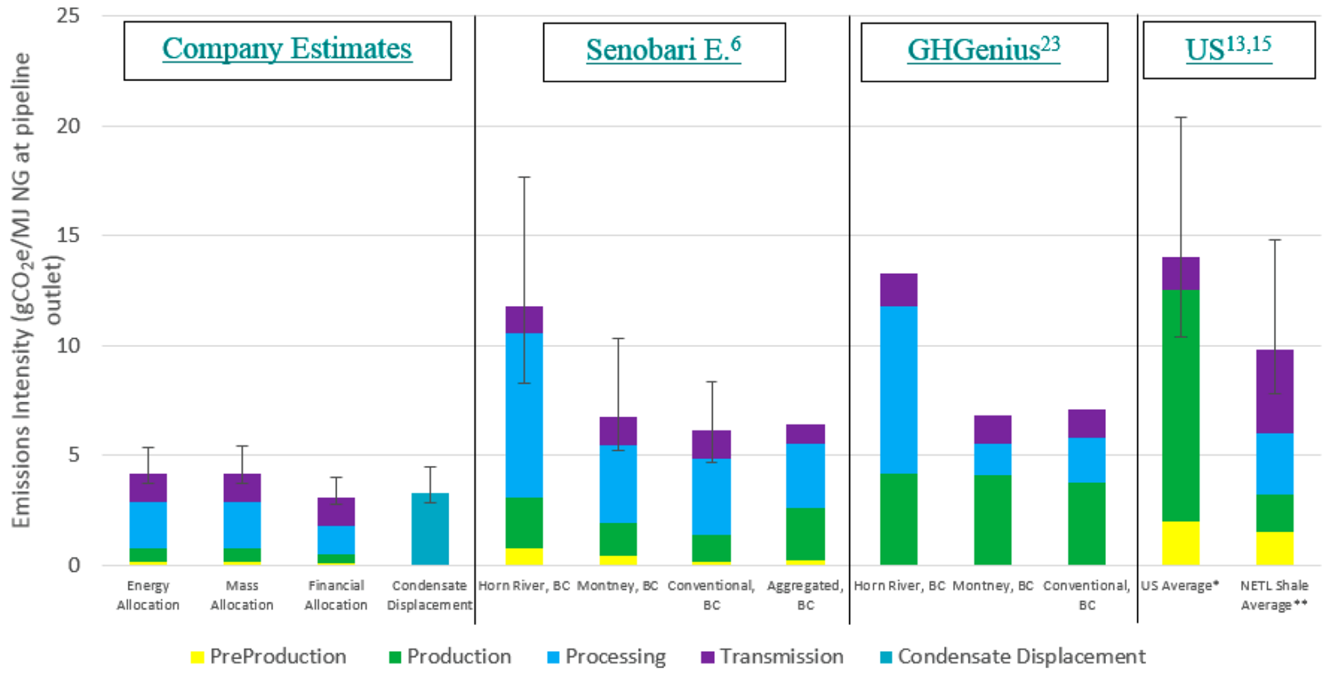

Figure 2. Upstream NG emissions intensity comparison to available BC estimates and aggregated US estimates. The whiskers for company and Senobari estimates are generated through an MC simulation and represent the 5th and 95th percentiles. Detailed MC simulation results are presented in S.6. US data variability bars include the maximum and minimum estimates from the considered studies. Under the category of "company estimates", one stacked bar is presented for each allocation method explored in this analysis. *US average based on Weber and Clavin's[11] best estimate is based on five different studies,[12−14,16,50] and production and processing emissions are combined and presented as production emissions as some studies combined the two stages. **NETL estimated an average emissions intensity for shale gas.[13]

impacts of oil and gas activity or as an alternative option to estimate tier 1 parameters (e.g., kilometers traveled and fuel efficiency of vehicles).

RESULTS

Emissions Intensity Estimates: Company Case Study. The upstream (preproduction, production, processing, and transmission) GHG emission intensity estimates for the company are illustrated in Figure 2. Figure 2 also includes a comparison to Senobari E.,[6] GHGenius,[20] US average (unconventional) compiled by Weber and Clavin[11] and US estimates from NETL (Skone et al.).[13] The company emissions intensities using both mass and energy allocation are 4.2 gCO_2e/MJ NG at transmission pipeline outlet (hereafter referred to as "gCO_2e/MJ NG"), whereas using financial and condensate displacement allocation results in 3.1 and 3.3 gCO_2e/MJ, respectively. The condensate displacement allocation method only subtracts total emissions of condensate production from the nonallocated company estimates and, therefore, cannot be represented with a breakdown using the same upstream categories. Additional information on the allocation methods can be found in section S.7 of the Supporting Information. Uncertainty in the estimates based on MC simulations is shown in black bars and demonstrates that there is significant overlap between these estimates. However, financial allocation results in lower emissions intensity than energy/mass-based allocation because of assumed product value: NG at \$3.40/GJ, condensate at \$11.10/GJ, and NGLs at \$4.01/GJ.[26] In comparison, Senobari E.[6] and GHGenius[20] emissions intensity estimates for Montney are ~1.5 and ~1.75× higher, respectively, compared to estimates in this case study. The uncertainty bars for company and Senobari E.[6] estimates were determined through MC simulation (5th and 95th percentiles). US data variability bars include the maximum and minimum estimates from the considered studies. GHGenius[20] emissions intensities are comparable to Senobari E.[6] but have higher production emissions (~2−3 gCO_2e/MJ NG) and lower preproduction and processing emissions (~0−1 and ~1−2.5 gCO_2e/MJ NG, respectively). The difference is likely due to the use of US data used to fill gaps in Senobari E.[6] GHGenius estimates higher methane emissions during production and less diesel use and methane emissions during preproduction.

The company's emissions intensity across all allocation methods is 2.5−10 gCO_2e/MJ NG lower compared to BC estimates and 5.5−10 gCO_2e/MJ lower compared to US estimates. The company's emissions intensity is primarily derived from processing-related NG stationary combustion accounting for ~50% of upstream emissions, vented methane emissions accounting for ~20% of upstream emissions, with the remaining 30% attributed to other sources, including emissions from the production of well materials (e.g., cement/concrete, well casing), electricity, fugitives, diesel, etc. This differs from studies on US NG production where methane emissions comprise 50%+ of the upstream emissions intensity.[13,51] This is likely because the company has assets that are relatively new and has adopted practices and technologies that have fewer emissions compared to conventional practices. Compared to typical industry practices, the company utilizes instrument air pneumatic devices on a significant portion of their constructed field facilities. This eliminates the use of instrument gas and associated methane emissions that would typically be emitted to drive pneumatic instrumentation and equipment. Operations that were acquired by the company (from other operators) are also being converted to instrument air. As an example, pneumatic

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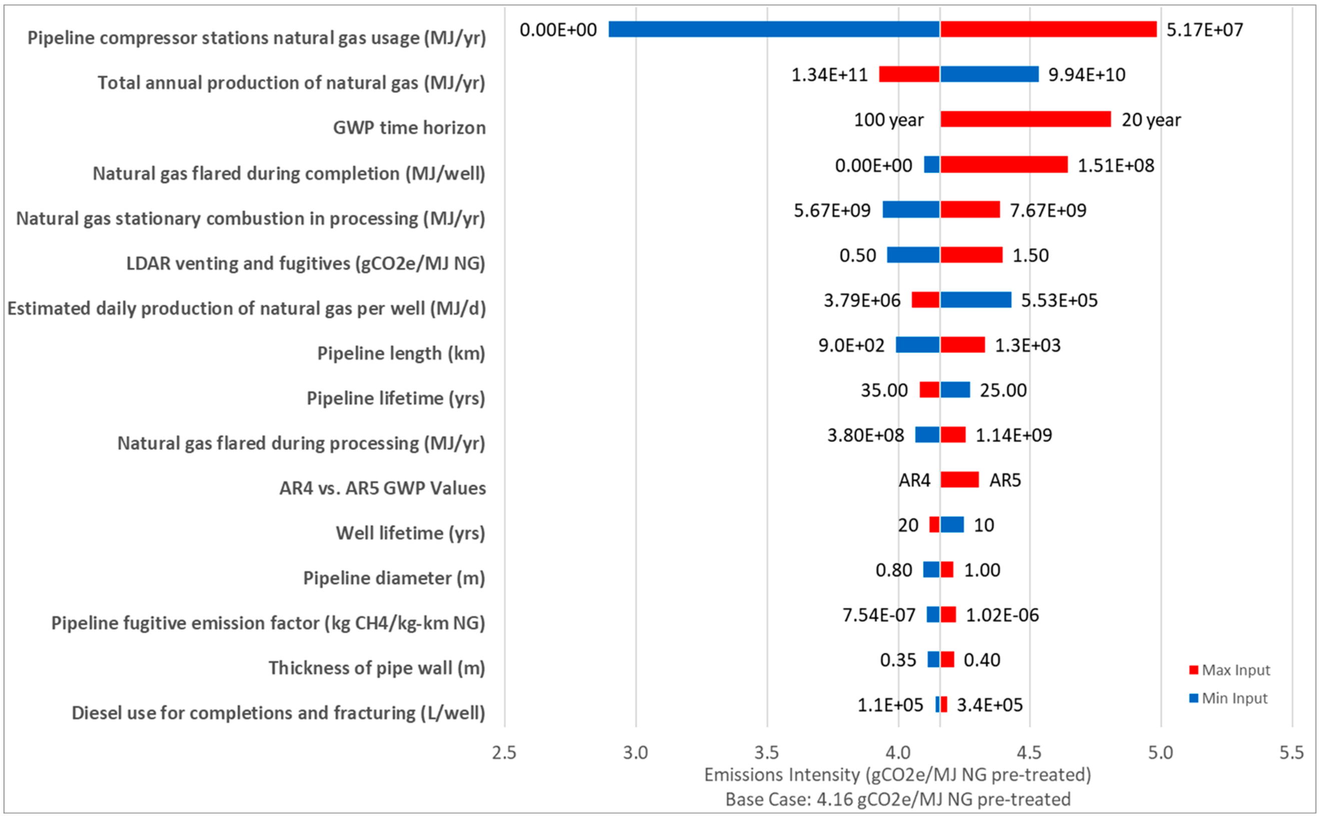

Figure 3. Sensitivity analysis of company upstream GHG emissions intensity estimates. The 15 most sensitive parameters are shown; the top five (pipeline natural gas usage, annual NG production, GWP horizon, flaring, and stationary combustion) are critical in determining the final emissions intensity as they affect the emissions intensity by up to 1.5 gCO_2e/MJ NG (~33% of estimate).

equipment contributes ~0.5 gCO_2e/MJ NG of the NETL Marcellus emissions intensity estimate (~5% of upstream methane emissions). In Alberta, a 2013 study done by CapOp Energy[52] estimated that there were 100,000 high bleed pneumatic devices across AB which could potentially be converted to air or low bleed and reduce GHG emissions by 4 $MtCO_2e$/yr. Although this data may be outdated, it provides a rough estimate to the potential emissions reduction of pneumatics conversion in AB alone. Two other factors that could lead to lower emissions estimates of AB and BC generally compared to the US are stricter venting and flaring regulations[45,46] in the provinces and the possibility that methane emissions are under-reported in the provinces by more than 50%.[7−9] The company is seen to have accounted for the majority of their methane emissions, compared to AB and BC average, through voluntary leak detection and repair (LDAR) programs as shown by Roda-Stuart.[27]

The 15 most sensitive parameters of the case study are presented in Figure 3, with the full sensitivity analysis presented in section S.6 of the Supporting Information. The five most critical parameters include pipeline compressor natural gas usage (0 MJ/yr being powered by renewable electricity, 5.17 × 10^{07} MJ/yr being completely powered by natural gas), annual production, whether the 100 year or 20 year time horizon is assumed for the GWP, flaring emissions, stationary fuel combustion, and methane emissions detected through LDAR programs. These five parameters affect the emissions intensity estimate by up to 1.5 gCO_2e/MJ NG when the variation in each parameter is tested individually. This analysis suggests that improving the accuracy of venting, flaring, and fugitive (VFF) estimates should be an important area of focus. The parameters that are not related to large sources of emissions or affect them minimally (e.g., well construction materials, NG composition) do not substantially drive variability of the emissions intensity estimate. It is worth noting that pneumatics does not play a large role in emissions estimates for this particular company due to their use of instrument air systems instead of gas-driven pneumatics. Many companies use gas-driven pneumatic systems which can account for approximately 0.5 gCO_2e/MJ according to Skone et al.[13]

Proposed Data Collection Template for Use in LCA Studies. Table 1 presents the tier 1 data parameters in the NETL model, that are required to estimate an upstream NG production GHG emissions intensity. This is a subset of all parameters considered that have been grouped into tiers (1 through 3−each parameter and its tier are listed in Table S.5 of the Supporting Information). The public data reported by the BC government only satisfy ~50% of tier 1 parameters, and some of this data is in an aggregated form. Incomplete tier 1 parameters result in a low-quality estimate of the emissions intensity and precludes insight into the sources or drivers of emissions. Assumptions around tier-1 data not publicly reported in BC lead to large uncertainties in emissions estimates that cannot be reduced unless region specific data parameters are obtained. For example, one parameter−venting from pneumatics−contributes to ~5% of Senobari E.'s[6] emissions intensity estimate for the Montney basin but ~0% in the case study as the company primarily uses instrument air systems. Publicly available data from AB satisfies only four of the 49 tier 1 parameters that are required to estimate an emissions intensity for each process in the upstream NG life

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Table 1. Proposed Data Template for Use in LCA Studies

	tier 1	tier 2	tier 3	example units	company data	default US data
Section A − Preproduction						
A.1-Well Drilling and Construction-Inputs						
average diesel use per well	x			L/well	1.70×10^{05}	3.10×10^{04}
average total production of well	x			bcf/well lifetime	8.91	3.25
average lifetime of well	x			yr	15	30
A.2-Hydraulic Fracturing (Optional)						
diesel use in fracturing	x			L/treatment-well	2.28×10^{05}	5.15×10^{04}
electricity use in fracturing	x			MWh/treatment-well	0	0
NG used as fuel	x			L/treatment-well	0	0
A.3-Total Deliveries and Water Management for Fracturing						
diesel use in trucks for water delivery	x			L/well	embedded in A.1	4.05×10^{04}
diesel use in trucks for sand/proppant delivery	x			L/well	embedded in A.1	1.86×10^{03}
diesel use in trucks for CO_2/N_2 delivery	x			L/well	embedded in A.1	1.86×10^{03}
A.4-Well Completion						
average volume of NG vented in well completion	x			kg/well or m^3/well	3.74×10^{05}	1.70×10^{03}
average volume raw NG flared in well completion	x			kg/well or m^3/well	0	2.63×10^{04}
average annual molar raw NG composition	x			mol % CH_4, CO_2, N_2, C2+	81.8, 0.7, 2.9, 14.5	78.8, 1.5, 1.8, 17.9
Section B − Production						
B.1-Workovers	tier 1	tier 2	tier 3	example units	company data	default US data
average raw NG vented in workover	x			kg/episode or m^3/episode	embedded in B.4	1.49×10^{05}
average raw NG flared in workover	x			kg/episode or m^3/episode	embedded in C.4 and C.5	2.63×10^{04}
frequency of workover episodes	x			episodes/yr	embedded in B.4, C.4, and C.5	4.05
B.2-Pneumatic Devices						
average NG vented in pneumatic devices	x			kg/yr or kg/well	embedded in B.4	5.80×10^{08}
average annual production of NG	x			kg/yr or kg/well	2.53×10^{09}	4.82×10^{11}
B.3-Other Point Source Emissions						
other point source emissions vented in production	x			kg/yr or kg/well	embedded in B.4	2.42×10^{07}
other point source emissions flared	x			kg/yr or kg/well	embedded in C.4 and C.5	4.27×10^{06}
B.4-Other Fugitives in Production						
average venting and fugitives from production (LDAR)	x			kg/yr or kg/well	0.96 gCO_2e/MJ	3.89×10^{08}
B.5-Liquid Unloading						
average NG vented during LU	x			kg/well	0	1260
average NG flared during LU	x			kg/well	0	0
average frequency of LU episodes	x			episodes/well	0	1700
Section C − Processing						
C.1-Sweetening/Amine Regeneration	tier 1	tier 2	tier 3	example units	company data	default US data
NG burned in reboiler as fuel	x			kg/yr or m^3/yr	embedded in C.7	6.29×10^{06}
NG vented during sweetening	x			kg/yr	embedded in B.4	0
NG flared during sweetening	x			kg/yr	embedded in C.4 and C.5	0
CO_2 released during sweetening	x			kg/yr	embedded in C.4 and C.5	3.64×10^{09}
average treated NG composition						
C.2-Dehydration						
annual NG burned as fuel	x			kg/yr or m^3/yr	embedded in C.7	4.14×10^{07}
vented NG during dehydration	x			kg/yr or m^3/yr	embedded in B.4	0
flared NG during dehydration	x			kg/yr or m^3/yr	embedded in C.4 and C.5	0
NG vented from separator	x			kg/yr or m^3/yr	8400	0
NG flared from separators	x			kg/yr or m^3/yr	embedded in C.4 and C.5	1.48×10^{06}
C.4 and C.5-Other point sources						
other point source emissions vented in processing	x			kg/yr	embedded in B.4	2.42×10^{08}
other point source emissions flared in processing	x			kg/yr	1.64×10^{07}	7.18×10^{07}
C.6-Compressor Stations						
NG used in gas powered compressors	x			kg/yr	embedded in C.7	1.07×10^{10}
electricity used in compressors	x			MWh	0	5.17×10^{07}
NG released from reciprocating gas powered compressors	x			kg/yr	embedded in B.4	0
NG released with centrifugal powered compressors	x			kg/yr	embedded in B.4	
C.7-Stationary Combustion						

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Table 1. continued

	tier 1	tier 2	tier 3	example units	company data	default US data
amount of NG consumed	x			kg/yr or m^3/yr	1.44×10^{08}	C.1-C.6
annual production of NG	x			kg/yr or m^3/yr	2.53×10^{09}	2.67×10^{09}
annual production of other coproducts (e.g., condensate, NGL)	x			kg/yr, m^3/yr, bbl/yr	25.3×10^{06}	
Section D - Transmission						
D.1-Transmission Operations	tier 1	tier 2	tier 3	example units	company data	default US data
length of pipeline	x			km	1100	971
NG consumption rate in compressors along pipeline	x			kg NG/yr-pipeline	2.46×10^{08}	2.67×10^{09}
electricity use for compressors	x			MWh	8.06×10^{05}	1.19×10^{05}
pipeline fugitive emissions	x			kg/yr	8.87×10^{-7} kg CH_4/kg-km	1.99×10^{09}
total NG transported	x			kg/yr	2.53×10^{08}	2.80×10^{11}
electricity emission factors	x			gCO_2e/kWh	600	608
D.2-Heavy Equipment use in pipeline construction						
diameter of pipeline	x			m or in.	9.14×10^{-01}	8.13×10^{-01}
thickness of pipeline wall	x			m or in.	0.0125	0.375
approximate lifetime of pipeline	x			yrs	30	30
diesel used in equipment and trucks during pipeline construction	x			L	3.15×10^{04}	2.78×10^{04}

cycle. Publicly available data in AB includes total emissions from facilities (CO_2, CH_4, N_2O), and cannot be disaggregated across NG or oil operations. Similarly, there is no method to determine the underlying activity and equipment emissions factor for different stages that contribute to overall emissions estimates. The case study satisfies 80% of tier 1 parameters with only moderate aggregation. The remaining 20% includes parameters related to transmission (not within the company's control and therefore part of their data collection activities). While this represents the most detailed data available to date, there are still opportunities for improvement. The data parameters that are still in aggregated form can be seen in Table 1 under the "company data" such as data in row A.3 labeled 'embedded in A.1' where diesel use for truck deliveries was included for total diesel use during drilling from the data received.

Data required to fully complete Table 1 would require producers to adjust measurement techniques. For example, the company metered overall fuel gas used at each facility in 2016, so fuel gas used by each process is not available. Conducting more detailed metering would allow for insight into potential efficiency improvements and emissions mitigation opportunities for each individual process. The additional data to populate tier 1 parameters which are needed to improve the quality of the LCA are technically possible and could be incorporated into the reporting requirements framework set up by government agencies.

In our case study, processing emissions (2.1 gCO_2e/MJ NG) are high compared to preproduction and production emissions (0.2 and 0.6 gCO_2e/MJ NG, respectively) because of aggregation issues. Some emissions that are currently in processing should be attributed to preproduction and production. For example, some stationary combustion assigned to processing are emitted during preproduction and production stages to power equipment such as compressors and power generation for well sites and pads. The aggregation of input data is an issue that precludes more detailed investigation of the drivers and potential mitigation measures associated with these activities. The dehydration unit requires fuel for combustion that is aggregated into the single stationary combustion emissions estimate for the entire facility. Other emissions in company operating data are also aggregated such as the VFFs.[53] By disaggregating the emissions data, they can be assigned to their respective processes. The benefit of assigning emissions to individual processes is to conduct more detailed contribution analysis (i.e., determine which activities contribute the most to emissions). Then, mitigation efforts can be focused on the activities that drive emissions and offer the lowest cost per ton of emissions reduction. Other than data aggregation, the only remaining data gaps are pipeline properties and pipeline O&M data parameters, which would require data from pipeline operators and were not available.

DISCUSSION

From the case study of one western Canadian upstream NG operator, insight into potential emissions reductions using best practices can be obtained. A simple opportunity is to switch gas-driven equipment such as pneumatics to air-driven systems. Switching to air-driven equipment allows more NG to be retained in the product stream as well as improve safety (in enclosed spaces) and reduce maintenance costs. Regular LDAR measurements allow producers to lower fugitive emissions by ensuring leaks are discovered and repaired in a timely manner. The company is also evaluating the benefits of mobile and satellite surveys to enhance their LDAR program. Through the application of these two emissions reduction methods, methane emissions could be decreased by up to roughly 2−5 gCO_2e/MJ NG[6,11,54] (up to 40% of upstream emissions intensity, depending on the project) for other existing operations in Western Canada and the US. The US average has higher pneumatics emissions than the case study, which can be mitigated with conversion to low bleed or air driven pneumatics. BC and the US have been observed to have higher fugitive emissions on average, compared to the case study, where LDAR programs could be implemented to reduce fugitive emissions. Better, more detailed representation of GHG emissions from NG production across Western Canada will help in constructing life cycle baseline GHG emissions estimates. These, in turn, can be used to develop strategies and demonstrate progress toward specific emissions reduction targets. For example, this study could be used to track emissions reduction impacts such as GHG reduction opportunities and unique innovative testing in the initial

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design of well sites and facilities (being implemented by the company).

To better determine Canadian NG emissions intensity, more transparency and availability of data is needed. This can be achieved by both providing more detailed emissions data (e.g., as the data is reported to regulatory agencies in BC) and revisiting the reporting structure itself. The current reporting structure includes aggregated data. Disaggregation would allow stakeholders to assess mitigation opportunities with reliable data and aid in the discussion of the emissions reduction goals set out by AB, BC, and Canada. A reporting structure that considers the use of upstream emissions data to conduct systems level analysis such as LCA will result in public data at a level of disaggregation appropriate to make emissions estimates that are transparent and consistent across projects and can inform discussions about the drivers of emissions and possible opportunities for mitigation. To implement the proposed data template, the AB and BC government would need to revise their current GHG reporting structure to determine the required data parameters to be included in the reporting structure. Currently, all industries within a jurisdiction follow the same reporting regulations, which has led to aggregated emissions being presented in public databases. Therefore, governments could consider the possibility of having different GHG reporting requirements (for the level of detail in the data submitted, not the reporting threshold) which would aid in data disaggregation.

Another goal of such a data template would be to make it transparent and available to the public. With the data publicly available, GHG emissions can be studied by academia and other stakeholders, which could aid in developing or implementing GHG mitigation opportunities. This would also allow for increased understanding of the GHG impacts from energy production in Canada. Detailed data would also help Canada clearly identify and compare emissions intensities from NG production to other regions in the world. In a world with growing LNG demand and increasing concern about climate change, showing that Canadian upstream performance is significantly better than other sources could simultaneously address climate goals and reward low-EI production practices. In summary, the company case study has allowed us to determine the emissions intensity from their well-to-gate life cycle emissions of NG production and provide insight for potential emissions reduction in the NG industry. If this revised data template is adopted, LCA studies will be facilitated without reliance on US data, and therefore, mitigation technologies can be better suited to Canadian operations.

■ ASSOCIATED CONTENT

Supporting Information

The Supporting Information is available free of charge at https://pubs.acs.org/doi/10.1021/acs.est.0c06353.

Additional information referenced in manuscript related to regulations, suggested reporting templates, sensitivity and Monte Carlo analysis, and GHG emissions allocation calculations (PDF)

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Notes

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■ ABBREVIATIONS

AB Alberta
BC British Columbia
EPA Environmental Protection Agency
GHG greenhouse gas
LCA life cycle assessment
LDAR leak detection and repair
LHV lower heating value
LNG liquefied natural gas
MC Monte Carlo
MJ megajoule
NG natural gas
NGL natural gas liquid
O&M operation and maintenance
US United States
VFF venting flaring and fugitives

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