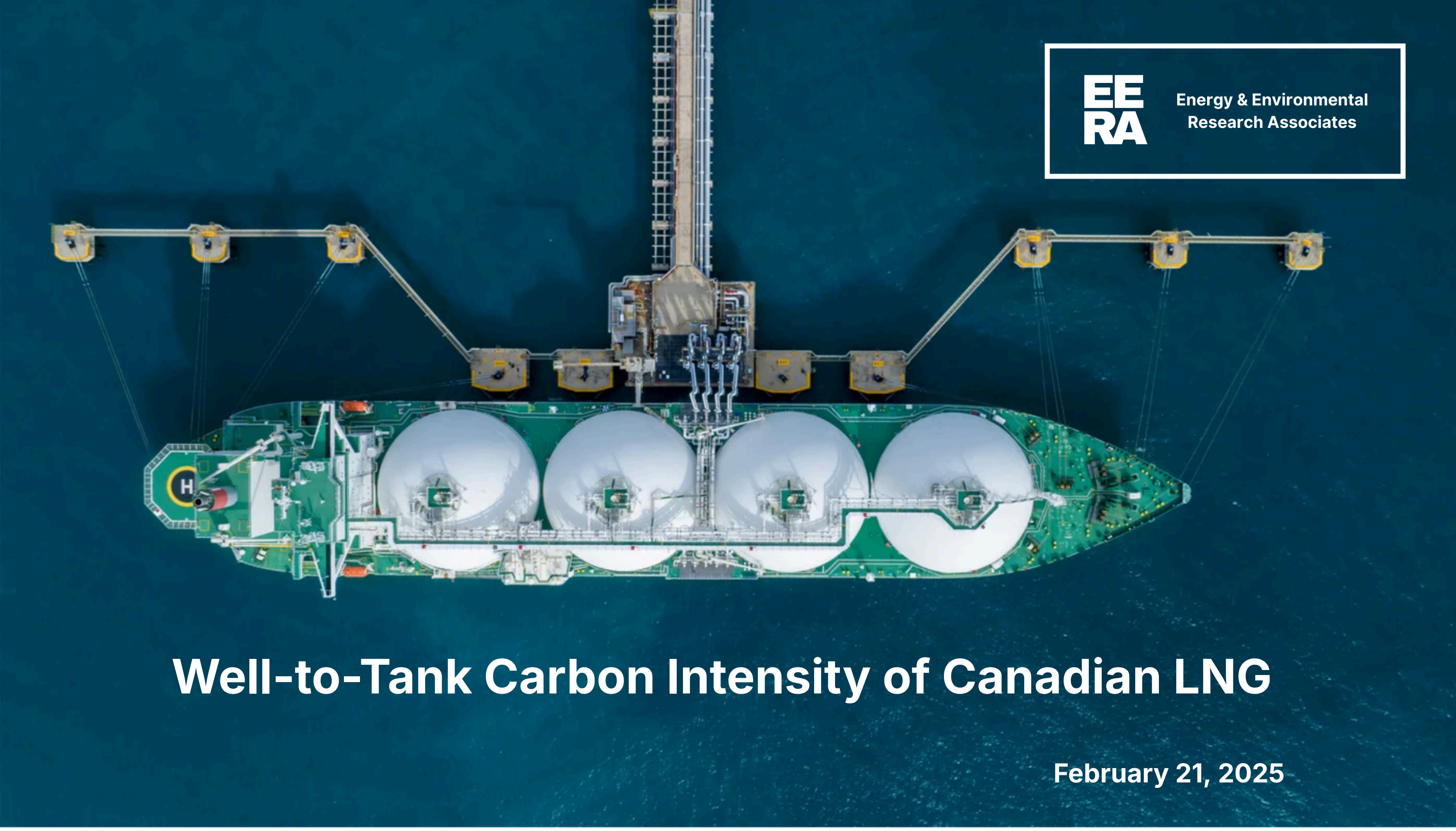

Well-to-Tank Carbon Intensity of Canadian LNG

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Key Findings and Conclusions

- Emissions from flaring, leakage, and venting in Canadian oil and gas activities accounted for up to 54% of provincial emissions and 16% of national sector emissions, demonstrating an area to limit significant CH_4 emissions and wasted energy.
- Canadian Greenhouse Gas Reporting Program estimates are 54% lower than satellite measurements for methane from natural gas activities.
- Improving transparency by separating the oil and gas sectors and breaking down emissions by supply chain stages can enhance accuracy. Using methodologies that detail individual GHG contributions allows for easier updates with evolving climate weightings and methodologies.
- Canada's projected liquefaction emissions (3.48 gCO_2e/MJ) are significantly lower than those reported for the U.S. (12.55 gCO_2e/MJ) and other nations. Due to the absence of large-scale LNG facilities as of early 2025, estimates are mostly based on proposed low-carbon scenarios.
- Canadian LNG imports and exports are currently small, and no LNG tankers were observed in the available AIS dataset for either import or export. This highlights the relatively small scale of Canada's LNG trade to date.
- Across the LNG supply chain, from production and extraction to liquefaction and transport, this study finds the average WtT values for Canadian LNG were 23.35 gCO_2e/MJ (AR6 GWP_{100}). This includes literature incorporation of low-carbon projections, yet the value is comparable to average fossil LNG WtT values (i.e. 21.31 gCO_2e/MJ, AR6 GWP_{100} for EU Imports[1]).

Background & Purpose

Canada and the U.S. produce abundant tight gas, shale gas, and associated gas, keeping prices historically lower than natural gas prices in Asia and Europe. This significant price gap drives North American producers to export liquefied natural gas (LNG) globally.[2] About 95% of Canada's oil and all of its natural gas production come from the Western Canadian Sedimentary Basin, spanning British Columbia, Alberta, Saskatchewan, and Manitoba.[3] Currently, Canada has four LNG plants for the domestic market and two import facilities but no export facilities. However, British Columbia (BC) currently has six LNG projects in development that have received export licenses, with most expected to be operational by 2030.[4,5]

In recent years, the Canadian government has supported building LNG export capacities to supply global markets, despite the Paris Agreement's[6] goal of reducing emissions and fossil fuel dependence. The nation's government maintains its LNG can compete with the U.S. Gulf Coast terminals due to shorter shipping distances to northeast Asian importers

[1] https://www.transportenvironment.org/uploads/files/WTT_CO2e_LNG_Imports_TE.pdf
[2] https://www.cer-rec.gc.ca/en/data-analysis/energy-markets/market-snapshots/2024/market-snapshot-exploring-canadas-future-in-lng-exports.html
[3] https://www.capp.ca/en/oil-natural-gas-you/oil-natural-gas-canada/
[4] https://natural-resources.canada.ca/energy-sources/fossil-fuels/canadian-liquified-natural-gas-projects
[5] Only a few LNG exports are under construction in Canada, but there are 29 valid LNG export licences.
[6] 194 States plus the European Union, https://www.un.org/en/climatechange/paris-agreement

and lower liquefaction energy requirements in a colder climate. The government also aims to position Canada as a leader in low-emission LNG production, with export facilities designed to use hydropower and renewable electricity for liquefaction, making them among the world's lowest-emission LNG facilities.[7] The BC province mandates all LNG projects have credible plans to achieve net-zero emissions by 2030.[8]

Despite Canada's largely clean electricity grid, where hydropower accounts for 64% of generation and nuclear and other renewables contribute another 21%, the timelines for building the necessary infrastructure and the sheer power requirements of LNG facilities pose significant challenges. British Columbia relies even more heavily on hydropower, which makes up 95% of its electricity production.[9] However, limited transmission capacity and an estimated eight-year wait for necessary upgrades in northern BC raise concerns that LNG projects may have to rely on natural gas-powered electricity rather than clean energy.[10]

While BC hydropower may be able to meet the demand for smaller projects like Cedar LNG (0.39 billion cubic feet per day (Bcf/d)), larger developments such as Ksi Lisims LNG (1.58 Bcf/d) could exceed its capacity, undermining expectations that Canadian LNG will be significantly lower in emissions compared to global competitors.[11] If all six proposed LNG facilities were built, they would require approximately 43 terawatt-hours of electricity annually—equivalent to 69% of the total BC electricity demand in 2022. To put this into perspective, meeting that demand would require more than eight Site C dams, a major hydroelectric project currently under construction on the Peace River, designed to generate about 5.1 terawatt-hours of electricity per year.[12]

Many environmental groups[13] and other organizations[14] oppose LNG development, arguing that expanding fossil fuel infrastructure contradicts climate goals. Studies indicate that methane emissions from LNG production, particularly from extraction, processing, and transport, may be significantly higher than previously understood.[15] Methane, a potent greenhouse gas (GHG), can undermine the climate benefits of LNG. Even as Canada takes steps to build cleaner LNG facilities powered by renewable energy, the full life cycle emissions, including upstream methane leaks, could still be substantial.

Ultimately, while Canada aims to position itself as a leader in lower-emission LNG, the reality of infrastructure constraints, energy demand, and methane leakage risks

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[7] https://www.cer-rec.gc.ca/en/data-analysis/energy-markets/market-snapshots/2024/market-snapshot-exploring-canadas-future-in-lng-exports.html
[8] https://www2.gov.bc.ca/assets/gov/environment/climate-change/ind/nzni/net-zero-new-industry-intentions-paper.pdf
[9] https://www.canada.ca/en/services/environment/weather/climatechange/climate-plan/clean-electricity.html
[10] https://financialpost.com/feature/lng-canada-start-shipping-2025-but-growth-uncertain
[11] https://financialpost.com/feature/lng-canada-start-shipping-2025-but-growth-uncertain
[12] https://cleanenergycanada.org/report/an-uncertain-future/
[13] e.g., https://climateactionnetwork.ca/wp-content/uploads/LNG-Position-Statement.pdf
[14] e.g., Public health advisory signed by over 500 physicians and nurses, https://cape.ca/press_release/lngharms/
[15] e.g., https://doi.org/10.1002/ese3.1934

complicates this vision. Additionally, shifting global energy policies and net-zero commitments from importing nations could reduce future demand for LNG. This raises the risk that newly built projects may become stranded assets, failing to deliver expected returns as the world accelerates its transition away from fossil fuels.[16]

This study aims to assess the upstream emissions of Canadian produced natural gas and LNG to determine whether it can truly be a low-GHG choice in the context of global and maritime climate goals.

Methodology

This study aggregates carbon intensity values from the LNG value chain from the well-to-tank (WtT), utilizing primary sources such as life cycle reports and emission inventory studies that provide emission rates for various greenhouse gas species. We include a look at the national greenhouse gas report, and observations from methane satellites. This study applies the same methodologies as used in the prior FuelEU WtT LNG study, please reference for additional details.[17]

All values are converted to grams of carbon dioxide equivalent units per megajoule (gCO_2e/MJ) to enable direct comparison of greenhouse gas emissions on an energy-weighted basis. However, we cannot apply weightings to previously aggregated values that do not provide a breakdown of the contributions from carbon dioxide, methane, and nitrous oxide (CO_2, CH_4, and N_2O), as there is no method to back-calculate. Many Canadian resources identified provided energy-weighted values for the combined WtT emissions. In those instances, we will report and include WtT estimates in the totals presented. In cases where the data allow, we have broken down the LNG production and supply chain into the following components or source categories.

Upstream	Extraction Production[18] Gathering and boosting
Midstream	Processing Compression Storage Transport (pipeline, truck, rail, tanker) Liquefaction Venting

[16] https://ieefa.org/articles/over-half-europes-lng-infrastructure-assets-could-be-left-unused-2030
[17] https://www.transportenvironment.org/uploads/files/WTT_CO2e_LNG_Imports_TE.pdf
[18] In some studies "production" also broadly included other upstream stages like well-drilling, recovery, production, processing, etc. together and reported estimates as a singular value.

Literature Review

This work conducted a comprehensive review of the peer-reviewed, gray, and white literature to identify GHG emission factors for the LNG value chain from WtT relevant to Canadian LNG. This work expands the methodology applied for a similar project, submitted to the IMO as part of ISWG-GHG 17, evaluating the regional variations in WtT emissions of LNG imported to the European Union.[19]

The literature review targeted emissions sources throughout the WtT supply chain, including natural gas production and extraction, processing, compression, transport (by pipeline, rail, and tanker), storage, and bunkering. Collected data includes emissions of CO_2, CH_4, and N_2O, along with CO_2e values, which express the cumulative impact of these emissions in terms of the global warming potential (GWP) of CO_2.

Canadian-focused studies often reported emissions in CO_2e without specifying the individual contributions of CO_2, CH_4, and N_2O. Data were provided primarily based on 100-year (GWP_{100}) potentials. We identified and documented the specific GWP values used by each study or filled in the values based on the Intergovernmental Panel of Climate Change Assessment Report (IPCC AR) utilized.

The search was conducted using Google Scholar and other research databases, prioritizing studies with direct relevance to Canadian LNG production. The literature reveals a lack of standardization in calculating upstream emissions, with no consistent methodology used. Studies differ in which processes to include, the level of detail, and the boundaries defined. Upstream processes are inherently unique, and methods can reflect these differences in equipment, transportation modes, distances, and other contextual factors.

Table 1

Datapoints for the Canadian LNG supply chain

Resource	Peer Reviewed	Government	Gray	Industry	NGO	Total
Studies	12	1	4	2	0	19
Values	143	10	25	6	0	184

This reflects the original values from the literature and does not account for additional values from EERA conversion.

19 literature resources were identified, providing nearly 200 CO_2e emission estimates and for various WtT processes (Table 1) . We identified 47 values for full WtT life cycle emissions, encompassing multiple stages of up- and midstream emissions. No Canadian-focused studies reported on the individual contributions of CO_2, CH_4, and N_2O. However, two studies reported solely on CH_4 emissions from the natural gas upstream with 26 emission-specific values. These data points are the basis for further analysis.

[19] ISWG-GHG 17/3. Available at https://www.transportenvironment.org/uploads/files/WTT_CO2e_LNG_Imports_TE.pdf

In addition to estimates of Canadian supply chain emissions within national boundaries, some studies focused on specific geographic areas (e.g. individual basins or operations) or covered provinces and territories within the country of scope (e.g. Alberta or British Columbia).

We extracted detailed information for each resource identified, including

Title, Year, Authors, Citation, DOI
Country, Sub-Region
Resource Type (e.g. peer-reviewed, gray[20], etc.)
Methods
GWP used
WtT EFs (CO_2e, CO_2, CH_4, N_2O) and units

Despite Canada's significant natural gas industry, the sector has received less research attention than oil and coal, particularly regarding upstream emissions. This is partly due to the overlap between oil and gas extraction, making it challenging to find studies that focus exclusively on natural gas. Moreover, until recent years, much of the research focused on downstream emissions and combustion. The earliest upstream Canadian WtT emissions study found in our review was published in 2013, with the most recent in 2024. The average and median year for all studies were both 2020, reflecting the rising importance of LCA methodologies in recent years.

Papers were differentiated between NG and LNG production, based on the inclusion or exclusion of the liquefaction process upstream. Canada has historically exported natural gas by pipeline, with LNG exports gaining attention only in recent years. The first Canadian LNG export facility permit was granted in 2014.

Table 2

Datapoints by supply chain scope, GWP weighting, and assessment reports

Resource	LNG	NG	GWP_{20}	GWP_{100}	AR4	AR5	AR6
Studies	11	8	1	15	6	7	3
Values	126	58	20	138	44	79	28

This reflects the original methodologies from the literature and does not account for the values after conversion. Not all studies require a GWP or AR input if the initial unit was not reported in CO_2e.

Additionally, we checked for the utilization of renewable energies, carbon capture technologies, or other emission-abatement methods within its assessment of upstream processes, if discussed in their methodology. The studies included 10 values that were specific to electrolysis derived LNG (E-LNG). It is worth noting that Canada is aiming to

[20] Gray literature encompasses publications created outside of traditional peer-reviewed or validated channels. We prioritize reputable gray literature sources that draw upon data from validations sources for reliability.

make its natural gas industry net-zero by 2030, requiring significant adoption of alternative energy sources and technologies.

Relevant studies were reviewed and selected, and GHG estimates associated with natural gas and LNG activities in Canada were compiled into a spreadsheet. This data was used in aggregation and analysis to report emission factors. Citations are provided in the References section.

Assumptions and Justifications

Only one study in the collected literature reported CO_2e values using GWP_{20}, but it was excluded from the analysis due to study limitations.

Four studies did not specify the IPCC AR values they applied for their CO_2e calculations. In these cases, we reasonably assumed the studies applied the most recent IPCC AR values available at the time of publication. Only one study, reporting in CO_2e, lacked any indication of the GWP weighting used. Based on contextual information, the date of analysis, and the reported values, it was reasonably inferred to align with GWP_{100}.

Canadian GHG Reporting Program

The Canadian Greenhouse Gas Reporting Program[21] (GHGRP) is a mandatory reporting initiative established by Environment and Climate Change Canada (ECCC) to track GHG emissions from large industrial facilities, emitting ≥10,000 tonnes CO_2e emissions per year, and submit annual reports detailing their emissions. It aims to track and support the nation's climate targets and progress to net-zero by 2050.

The emissions data reported under the GHGRP are publicly available in two separate files. One file categorizes total emissions for each facility, categorized by gas type (i.e. CO_2, CH_4, N_2O) and includes CO_2e units. Meanwhile, the other details emissions by source category. Source categories include stationary fuel combustion, on-site transportation, leakage, venting, flaring, industrial processes, waste, wastewater.

Beginning with the 2022 emissions dataset, the most recently available reporting, the GHGRP has updated its GWP values to reflect the IPCC's Fifth Assessment Report (CH_4=28, N_2O=265). These updated values align with those used in Canada's 2024 National Greenhouse Gas Inventory, ensuring consistency with international reporting requirements under the United Nations Framework Convention on Climate Change (UNFCCC).

[21] https://open.canada.ca/data/en/dataset/a8ba14b7-7f23-462a-bdbb-83b0ef629823

The data were filtered to include only the 2022 reported values and narrowed the focus to match the project scope of facilities relevant to the natural gas industry. For the source category dataset, an additional filter was applied to focus specifically on emissions from venting, leakage, and flaring, allowing for a detailed analysis of these particular sources relative to the total emissions of the facilities.

Flaring, leakage, and venting are significant sources of GHG emissions during the upstream life cycle of natural gas, particularly during extraction, processing, and transportation. These categories represent wasted energy, with natural gas being burned off or directly released into the atmosphere, contributing to a significant amount of GHG emissions.

While Canada does not fall in the top nine countries in the latest 2024 World Bank report[22] on flaring, it ranks 24th globally, placing it in the top 30. In our previous LNG WtT analysis, we found that the top three countries exporting to the EU with the highest WtT emissions were also among the top nine countries responsible for over 75% of global flaring volumes, underscoring the importance of addressing emissions from these sources.[23]

Because natural gas is primarily composed of CH_4, flaring is a controlled process that burns off excess or byproduct natural gas when capture and utilization are not feasible.[24] Combustion converts CH_4 to CO_2, which has a lower GWP. Leakage, on the other hand, is unintentional and occurs due to faulty equipment, pipeline failures, or improper maintenance, allowing CH_4 to escape into the atmosphere. Venting is a deliberate release of unburned gas, typically used when immediate pressure relief is needed and flaring is not feasible or in the equipment design. Since leakage and venting do not involve combustion, they result in higher methane emissions (Table 3).

Table 3

Emissions Breakdown of Flaring, Leakage, and Venting

Emission Source	% CO_2	% CH_4	% N_2O
Flaring	88.29	11.54	0.16
Leakage	2.17	97.83	0.00
Venting	10.40	89.60	0.00

For the following GHGRP sections, the combined reported GHGs for facilities using the total emissions file will be referred to as ‘Total CO_2e’. The summed totals of source categories, filtered to include only flaring, leakage, and venting, will be referred to as ‘Reported Source Categories’. All numbers in the tables, including those ‘Total CO_2e’,

[22] https://thedocs.worldbank.org/en/doc/d01b4aebd8a10513c0e341de5e1f652e-0400072024/original/Global-Gas-Flaring-Tracker-Report-June-20-2024.pdf
[23] https://www.transportenvironment.org/uploads/files/WTT_CO2e_LNG_Imports_TE.pdf
[24] Flaring of gas, including from oil production, occurs due to a combination of factors, including economic infeasibility (lack of infrastructure), safety concerns (pressure relief), and technical limitations (impurities in the gas that make transport difficult).

‘Reported Source Categories’, ‘Flaring’, ‘Leakage’, and ‘Venting’, are reported in tonnes CO_2e, unless otherwise specified.

The filtered GHGRP dataset revealed four unique facility North American Industry Classification System[25] (NAICS) codes, as seen below (Table 4). In the GHGRP, oil and gas extraction activities are intermingled, as many facilities engage in both oil and natural gas extraction simultaneously. Due to the overlap in operations, it is not feasible to separately account for emissions from oil extraction versus natural gas extraction within the reporting framework.

Table 4

North American Industry Classification System Codes for Natural Gas Facilities

NAICS Code	Description
211110	Oil and gas extraction, except oil sands!
211113	Conventional oil and gas extraction^
221210	Natural gas distribution*
486210	Pipeline transportation of natural gas

!Oil sands extraction falls under NAICS code 211120 - Crude Petroleum Extraction
^Facilities using only conventional techniques fall under 211113, while those using unconventional methods or a combination of both are classified under 211110.
∗Refers to the local delivery of natural gas from the transmission pipelines to residential, commercial, and industrial customers. This involves the distribution network that connects pipelines to end-users, which may include fuel suppliers.

The filtered dataset for oil and natural gas facilities included 130 reporting companies, while the filtered source category dataset included 129 companies. The difference is due to *Six Nations Natural Gas Company Limited* (NAICS 221210), which was present in the facilities dataset but missing from the source category dataset. This means that this local utility did not report any emissions attributable to venting, leakage, or flaring.

Some companies report only a single row of emissions data, representing a single facility, while others have larger operations spanning multiple NAICS codes and locations, requiring multiple entries. *Canadian Natural Resources Limited* had the highest number of reported facilities, with 89 rows of emissions data, whereas the majority of companies (88.5%) reported emissions for 10 or fewer facilities. This variation reflects the differing scales of operations among reporting entities.

Nationwide and provincial natural gas production volumes for 2022[26] were included in terajoules (TJ), which can be referenced against the reported GHGs to assess the relationship between production and emissions. By using production energy volumes, our team could calculate CO_2e/MJ emission factors to better understand the emissions intensity of these facilities. However, since extraction activities in the GHGRP involve both

[25] A standardized system used by the United States, Canada, and Mexico to classify businesses based on their economic activities. Each NAICS code corresponds to a specific industry sector.
[26] https://www.iea.org/data-and-statistics/data-tools/energy-statistics-data-browser

oil and gas, these emissions cannot be attributed solely to natural gas. Emission factors in the following sections are skewed by the inclusion of oil-related emissions, as a result, the calculated factors may overestimate the emission intensity for natural gas.

By Province/Territory

The total combined emissions by all reporting Canadian natural gas facilities amounted to 49,615,311 tonnes CO_2e, with the top three emitters—Canadian Natural Resources Limited, Cenovus Energy Inc., and Nova Gas Transmission Ltd.—accounting for 33.32% of the total GHG emissions. Facilities were distributed across various provinces and territories, with those in Alberta accounting for 59% of the total emissions, followed by Saskatchewan at 17%, and British Columbia at 16%, together representing 93% of the total CO_2e emissions (Table 5).

The broad emission intensities (gCO_2e/MJ) for the provinces and territories are calculated using the total GHGs from the oil and gas sector and the respective marketable natural gas production volumes. These values reflect emissions from both oil and natural gas extraction, meaning that in provinces where oil production substantially greater than for natural gas (i.e. Ontario), the emissions intensities correspond to the marketable gas produced, and thus are elevated as they are associated mainly with other energy production. Better processes in the GHGRP that separate oil and gas reporting would enable finer-grained analysis of the natural gas upstream emissions (Table 5).

Table 5

GHGRP Emissions from the Oil & Gas Sector by Province or Territory

Province or Territory	Total CO_2e	% CO2	% CH4	% N2O	Production (TJ) (2022)	gCO_2e/MJ
Alberta	29,202,852	80.1	17.46	2.44	4,137,652	7.06
Saskatchewan	8,501,650	83.4	15.92	0.68	118,796	71.57
British Columbia	7,745,732	87.65	11.53	0.81	2,409,676	3.21
Ontario	2,178,993	70.6	29.01	0.39	2,443	892.04
Newfoundland and Labrador	1,202,092	95.61	3.82	0.57	-	-
Manitoba	608,805	81.87	17.97	0.16	-	-
Quebec	93,722	44.07	55.62	0.31	-	-
Northwest Territories	70,019	96.95	2.49	0.56	2,278	30.74
New Brunswick	11,447	89.57	10.03	0.41	1,778	6.44
Total	**49,615,311**				**6,672,623**	**Average: 7.44**

The values of other emission types reported in the GHGRP are negligible

CO_2 emissions accounted for more than 80% of the total emissions in most provinces and territories, except for Ontario and Quebec, where CH_4 emissions represented 29% and 56% of their respective totals (Table 6). In these provinces, CH_4 leakage was a significant contributor to total emissions, accounting for 23% of GHGs in Ontario and 45% in Quebec—the highest percentages of any province. Additionally, Quebec had the highest share of emissions from venting, another major source of CH_4. While Ontario's venting exceeded the combined percentage of Canadian natural gas emissions from venting, other provinces still had higher shares of venting emissions than Ontario (Table 6).

Table 6

GHGRP Flaring, Leakage, and Venting Emissions from Oil & Gas by Province or Territory

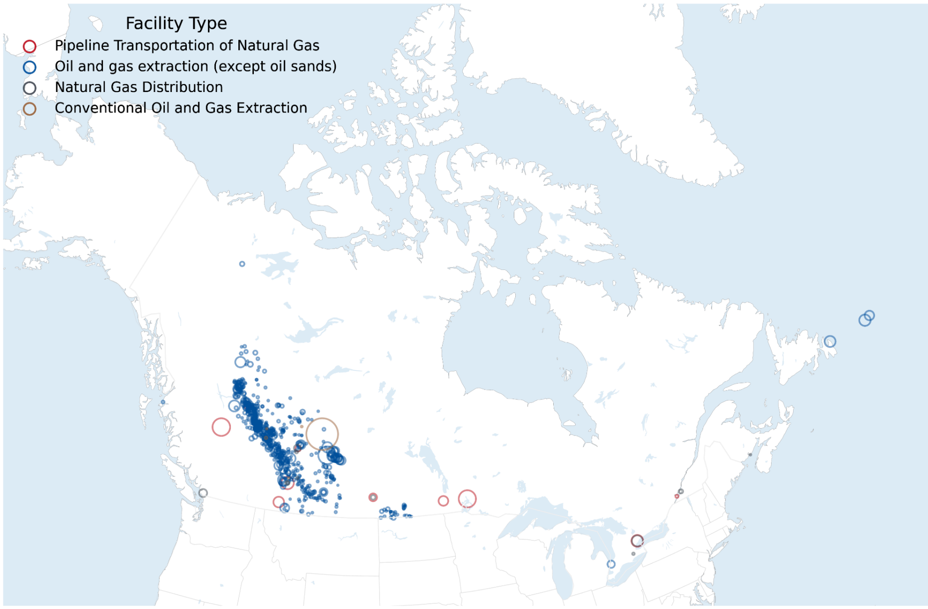
		Reported Source Categories (MT CO_2e)				
Province or Territory	**Total CO_2e**	**Flaring**	**Leakage**	**Venting**	**Sum F+L+V**	**NG Production m^3/year**
Alberta	29,202,852	1,944,351	400,172	1,703,417	4,047,940	110,929,015,375
		(6.66 %)	(1.37%)	(5.83%)	(13.86%)	
Saskatchewan	8,501,650	541,161	118,382	386,845	1,046,388	3,184,867,100
		(6.37%)	(1.39%)	(4.55%)	(12.31%)	
British Columbia	7,745,731	387,296	276,437	816,744	1,480,477	64,602,587,078
		(5.00%)	(3.57%)	(10.54%)	(19.11%)	
Ontario	2,178,993	32,811	501,501	217,121	751,432	65,488,000
		(1.51%)	(23.02%)	(9.96%)	(34.49%)	
Newfoundland and Labrador	1,202,092	220,626	7,552	7,261	235,438	—
		(18.35%)	(0.63%)	(0.60%)	(19.59%)	
Manitoba	608,805	181,474	48,515	83,984	313,973	—
		(29.81%)	(7.97%)	(13.79%)	(51.57%)	
Quebec	93,722	81	41,957	17,213	59,251	—
		(0.09%)	(44.77%)	(18.37%)	(63.22%)	
Northwest Territories	70,019	2,895	83	1,505	4,482	61,066,634
		(4.13%)	(0.12%)	(2.15%)	(6.40%)	
New Brunswick	11,447	6,064	104	—	6,168	47,680,700
		(52.98%)	(0.91%)	—	(53.89%)	
Combined Total	**49,615,311**	**3,316,759**	**1,394,702**	**3,234,089**	**7,945,550**	**178,890,704,887**
		(6.68%)	(2.81%)	(6.52%)	(16.01%)	

Government production volumes[27] for each province or territory were included to compare the GHG emissions from natural gas related facilities to the output of marketable natural gas. There is no commercial natural gas production in Quebec, Manitoba, or Newfoundland and Labrador, so the reported emissions are solely attributed to oil production, with natural gas as a byproduct. The geographic distribution of emissions is shown in Figure 1 below.

[27]https://www.cer-rec.gc.ca/en/data-analysis/energy-commodities/natural-gas/statistics/marketable-natural-gas-production-in-canada.html

Figure 1

Geographic Distribution of Canadian Natural Gas and LNG Infrastructure Emissions



By NAICS Facility Type

The GHGRP reporting is dominated by unconventional or mixed oil and gas extraction operations, with over 680 reported values. In contrast, other facility types report far fewer values, with only 5 facilities for conventional extraction, 17 for transmission pipelines, and 12 for distribution networks (Table 7). Despite only 17 reported facilities for pipeline transportation, its total emissions (11,593,630 tonnes CO_2e) still account for roughly a third of the total GHGs from the 680 reported extraction sites (33,217,814 tonnes CO_2e).

The largest GHG contributor among NAICS facility types relevant to the natural gas industry was unconventional and mixed oil and gas extraction. In contrast, conventional oil and gas extraction contributed significantly less but was reported at only five sites, indicating that most extraction operations involve at least some unconventional methods. CO_2 was the dominant emissions type across most activities (≥80%), except for natural gas distribution, where CH_4 made up 52% of emissions. N_2O was a minor but notable component across all facilities, with the highest share (2.42%) seen in conventional oil and gas extraction (Table 7).

Table 7

GHGRP Emissions from the Oil & Gas Sector by NAICS Facility Type

NAICS Facility Type	Count	Total CO_2e	% CO_2	% CH_4	% N_2O
Oil and gas extraction, except oil sands	680	33,217,814	82.16	15.86	1.98
Pipeline transportation of natural gas	17	11,593,630	83.21	16.20	0.60
Conventional oil and gas extraction	5	3,638,640	80.73	16.85	2.42
Natural gas distribution	12	1,165,228	47.24	51.60	1.16
Combined Total		**49,615,311**			

The values of other emission types reported in the GHGRP are negligible

'Source' emissions from flaring, leakage, and venting activities represented 16% of the total GHG emissions from all Canadian natural gas facilities. These 'source' emissions made up just 1% of total GHGs from conventional natural gas extraction, but rose to 18% for unconventional and mixed extraction. Unconventional and mixed extraction had the highest flaring and venting rates, both in emitted tonnes CO_2e and as a percentage of the facilities' total emissions. Flaring represents less than 1% of total GHGs for all other facility types (Table 8).

'Source' emissions represented 74% of the total GHGs from natural gas distribution (Table 8). Despite distribution pipelines being the smallest operation in terms of total GHG emissions (1,165,228 tonnes CO_2e), they had the highest leakage rates of any facility type (790,850 tonnes CO_2e), with leakage accounting for 68% of the facilities' total GHG emissions (1,165,228 tonnes CO_2e) and 92% of emissions from associated flaring, leakage, and venting activities (863,932 tonnes CO_2e).

Table 8

GHGRP Flaring, Leakage, and Venting Emissions from Oil & Gas by NAICS Facility Type

NAICS Facility Type	Total CO_2e	Source CO_2e	Flaring	Leakage	Venting
Oil and gas extraction, except oil sands	33,217,814	5,936,311	3,237,131	328,902	2,370,278
		(17.87%)	(9.75%)	(0.99%)	(7.14%)
Pipeline transportation of natural gas	11,593,630	1,108,730	57,980	253,406	797,344
		(9.56%)	(0.50%)	(2.19%)	(6.88%)
Conventional oil and gas extraction	3,638,640	36,577	11,058	21,544	3,975
		(1.01%)	(0.30%)	(0.59%)	(0.11%)
Natural gas distribution	1,165,228	863,932	10,591	790,850	62,492
		(74.14%)	(0.91%)	(67.87%)	(5.36%)
Combined Total	**49,615,311**	**7,945,550**	**3,316,759**	**1,394,702**	**3,234,089**
		(16.01%)	(6.68%)	(2.81%)	(6.52%)

Leakage is significantly higher for natural gas distribution (790,850 tonnes CO_2e) than for pipeline transportation (253,405 tonnes CO_2e). The significant amount of CH_4 leakage occurring during natural gas distribution is largely due to the differences in design, maintenance, and oversight compared to the transmission pipeline system (Box 2).

Box 2

The difference between distribution and transmission pipeline networks for natural gas

Distribution pipelines are generally smaller, low-pressure systems, made with plastic, plastic composites, or older systems may be constructed from cast iron. These materials become brittle with age, leading to fractures and leaks. For example plastic Aldyl-A pipes have been linked to ongoing failures despite recommendations for replacement. In contrast, transmission pipelines, used in the pipeline transportation of natural gas, are designed and regulated to meet stricter standards for safety and durability, with greater regulatory oversight. These pipelines are typically larger, high-pressure systems. They are predominantly made from high-carbon steel, a strong and resilient material, and are fabricated in rolling mills, inspected to meet safety standards, and customized to fit the specific needs (e.g., soil conditions) of the route they will follow. The transmission systems are subject to more rigorous maintenance and monitoring to minimize failure incidences.[28]

Top-Down Measurement of Upstream Methane

Methane emissions from oil and gas operations are a major concern, as methane is a highly potent GHG. Venting and fugitive leaks are two significant sources of methane, as discussed in the previous section. Top-down observations work by detecting atmospheric gas concentrations and working ‘backward’ to estimate emission sources, typically using satellites, aircrafts, or ground-based remote sensing. In contrast, bottom-up approaches often estimate emissions based on government or industry-reported data. While useful, these bottom-up factors usually rely on assumptions and averages, which can lead to underestimations, especially when applied to diverse real-world conditions where leaks and venting may be higher than expected.

Multiple agencies and studies[29] using top-down approaches have found that methane emissions, particularly from venting and fugitive leakage, are significantly higher than the values reported by government agencies and gas industries. The following sections assess data from top-down sources, largely derived from satellite observations, to quantify methane across regions.

TROPOMI Methane Satellite

Satellite observations have revealed that many nations have been significantly underreporting methane emissions from their oil and gas sector. National emission inventories submitted to the UNFCC consistently report lower upstream methane emissions than those observed via satellite. Data from the Tropospheric Monitoring Instrument[30] (TROPOMI), using a top-down approach to infer emissions from atmospheric

[28] https://pstrust.org/wp-content/uploads/2015/09/2015-PST-Briefing-Paper-02-NatGasBasics.pdf
[29] e.g., including but not limited to, https://www.npr.org/2024/03/13/1237962030/climate-emissions-methane
https://www.iea.org/news/methane-emissions-from-the-energy-sector-are-70-higher-than-official-figures
https://www.edf.org/media/new-study-provides-comprehensive-estimates-methane-emissions-canadas-oil-and-gas-industry
[30] https://www.tropomi.eu/

methane measurements, showed a pronounced gap in emissions from government-reported values.

To align with other findings in this study, methane emission estimates (Gg-CH_4/year) were converted into gCO_2e/MJ using data from a 2023 Nature Communications study.[31] The TROPOMI satellite observations cover May 2018-February 2020, while the UNFCCC reports are for 2019. For consistency and comparability, we applied 2019 natural gas production values when converting to gCO_2e/MJ and used the latest AR6 GWP weightings.

Globally, methane emissions from the oil & gas sector are estimated to be 30% higher than what governments report. In Canada and the U.S., this discrepancy was found to be even greater, with Canada underreporting methane emissions by nearly 54% and the U.S. by 55% (Table 9 and Figure 2).

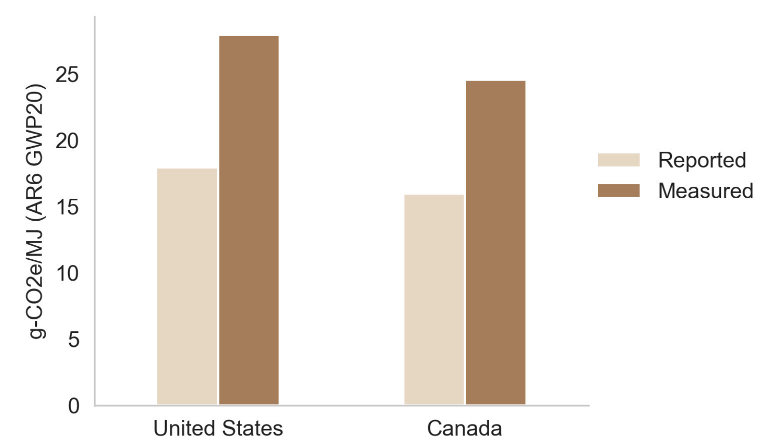
Table 9

Measured vs Reported Methane Emissions from the Natural Gas Sector (AR6, gCO_2e/MJ)

Country	Resource	AR6 GWP	CH_4 (gCO_2e/MJ)	2019 Production (TJ)
Canada	UNFCC Report	100	5.78	37,212,841
		20	16.00	
	TROPOMI Measure	100	8.88	
		20	24.58	
United States	UNFCC Report	100	6.50	7,385,467
		20	17.97	
	TROPOMI Measure	100	10.09	
		20	27.93	

Figure 2

Measured vs Reported Natural Gas CH_4 Emissions from Canada and the U.S. (AR6, GWP_{20}, gCO_2e/MJ)



[31] https://opendata.pku.edu.cn/dataset.xhtml?persistentId=doi:10.18170/DVN/PRSYW1

IEA Upstream Methane Tracker

The IEA's Methane Tracker estimates methane emissions from global oil and gas operations by applying country-specific emission intensities based on production type. These intensities are derived from data like satellite observations, infrastructure age, operator types (international, independent, or national companies), average flaring intensity, regulation strength, and methane-specific policies.

The IEA Global Methane Tracker combines data from public sources and satellite measurements, scaling U.S. emission intensities (derived from the U.S. Greenhouse Gas Inventory[32]) to other countries using factors like infrastructure age, operator type, and flaring volumes. Scaling considers national regulations and methane-related policies,[33] along with satellite data from Kayrros[34] and other sources like the World Bank.[35] These satellite measurements are currently limited to large emission sources, leaving out the smaller, day-to-day operations that collectively contribute to a significant portion of overall emissions, potentially underestimating total methane emissions across the industry.

For our analysis, methane emissions reported by the IEA in kilotons (kt-CH_4/yr) were converted to gCO_2e/MJ using AR6 report GWP-weighted emission intensities (GWP_{100}). National natural gas production volumes for 2023[36] were included in TJ, aligning with the energy content measurements used in our assessments.

Most of these emissions were observed from onshore gas production rather than offshore, for which only Trinidad & Tobago had significant offshore operations. Vented emissions had a higher emission intensity than fugitive emissions in all countries and sources. The methane intensity from gas extraction and production were substantially higher than the emissions from pipelines and facilities (Table 10 and Figure 3).

Table 10

IEA Methane Tracker 2023 Measurements, Upstream Natural Gas CH_4 Emissions (AR6, GWP_{100}, gCO_2e/MJ)

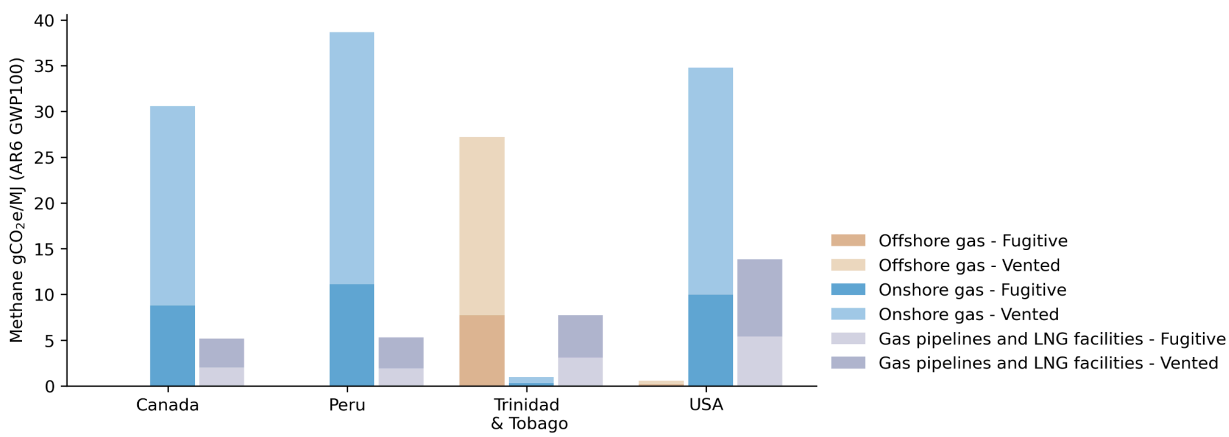
Country	Segment	Sub-segment	CH_4 (gCO_2e/MJ)	kt CH_4/yr	2023 Production (TJ)
Canada	Offshore gas	Fugitive	—	—	8,162,734
		Vented	—	—	
	Onshore gas	Fugitive	21.83	240	
		Vented	8.76	598	
	Pipelines & Facilities	Fugitive	2.01	55	
		Vented	3.18	87	

[32] https://www.epa.gov/ghgemissions/inventory-us-greenhouse-gas-emissions-and-sinks
[33] https://www.iea.org/policies
[34] https://methanewatch.kayrros.org/
[35] https://www.worldbank.org/en/publication/worldwide-governance-indicators
[36] https://www.iea.org/data-and-statistics/data-tools/energy-statistics-data-browser

Country	Segment	Sub-segment	CH_4 (gCO_2e/MJ)	kt CH_4/yr	2023 Production (TJ)
United States	Offshore gas	Fugitive	0.16	20	37,270,800
		Vented	0.41	51	
	Onshore gas	Fugitive	9.95	1245	
		Vented	24.84	3107	
	Pipelines & Facilities	Fugitive	5.37	672	
		Vented	8.48	1061	
Trinidad & Tobago	Offshore gas	Fugitive	7.73	25	964,800
		Vented	19.46	63	
	Onshore gas	Fugitive	0.31	1	
		Vented	0.62	2	
	Pipelines & Facilities	Fugitive	3.09	10	
		Vented	4.63	15	
Peru	Offshore gas	Fugitive	—	—	616,268
		Vented	—	—	
	Onshore gas	Fugitive	11.12	23	
		Vented	27.56	57	
	Pipelines & Facilities	Fugitive	1.93	4	
		Vented	3.38	7	

Figure 3

IEA Methane Tracker 2023 Measurements, Fugitive & Vented Natural Gas Emissions ($AR6$, GWP_{100}, gCO_2e/MJ)



Carbon Intensity of Canadian WTT LNG Chain

National-level estimates of the WtT carbon intensity of NG and LNG were calculated for the Canadian LNG chain based on the estimates identified from the literature. Estimates are presented in gCO_2e/MJ, accounting for the total emissions for CO_2, CH_4, and N_2O (where available), and weighted for a 100-year GWP timescale.

Unfortunately, there were no published Canadian estimates weighted for a 20-year GWP timescale, and no studies breaking down the individual gas contributions of their weighted values, to conduct an analysis at this timescale.

Table 11
Global Warming Potentials from the Fourth, Fifth, and Sixth Assessment Reports

		CO_2		CH_4		N_2O	
		GWP_{20}	GWP_{100}	GWP_{20}	GWP_{100}	GWP_{20}	GWP_{100}
AR4		1	1	72.0	25.0	289	298
AR5[37]	No CC fb	1	1	84.0	28.0	264	265
	W. CC fb	1	1	86.0	34.0	268	298
AR6	Fossil	1	1	82.5	29.8	273	273
	Non-fossil	1	1	79.7	27.0	273	273

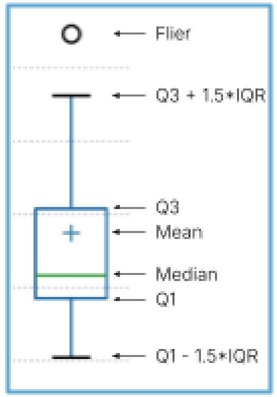
The goal was to present results utilizing the most recent AR6 GWP values, however literature that presented CO_2e values without breaking down the contributions of individual GHGs cannot be simply rescaled to other AR values. As GWP assigns specific weights to each GHG species, without knowing the individual contributions of CH_4 or N_2O,[38] or having data that allows for conversion from other units (e.g., g CH_4), we cannot accurately apply and adjust the estimate to reflect alternate AR estimates.

Subsequent sections include additional detail on the process-level gCO_2e/MJ emissions and an analysis of WtT values from the literature.[39]

Box 3 describes the anatomy of a boxplot, used to display the distribution of emission factors across the different countries by displaying the median, quartiles, and potential outliers. They can highlight the variations in literature values, offering insights into the consistency and range of reported values.

[37] AR5 values for fossil methane are higher by 1 and 2 for the 20 and 100 year metrics, respectively.
[38] Prior analysis, performed for LNG imports to the European Union, indicates that contributions of N_2O to total CO_2e emission estimates are generally limited, https://www.transportenvironment.org/uploads/files/WTT_CO2e_LNG_Imports_TE.pdf
[39] Note that computing the arithmetic sum of WtT values along the supply chain (e.g. gCO_2e/MJ from production and extraction + gCO_2e/MJ from processing etc...) may yield incongruous results compared to WtT estimates in the literature, particularly where estimates of process emissions are sparse.

Box 3
Anatomy of a boxplot



AR6

In this section, we present AR6 GWP values (Table 11) as reported. No studies offering enough information for accurate conversion were included in the AR6 assessment. In total, we identified 43 literature values that were either provided in AR6 gCO_2e values, or could be converted based on the pollutant species provided. These results are shown in Table 12 and Figure 4.

Shapiro-Wilk tests for normalcy of the data indicate that the AR6-reported literature data for Canada do not follow an approximately normal distribution (test statistics = 0.905, p = 0.002).[40] Using mean values alone does not provide a reasonable measure of the central tendency of the data. In all cases we also provide summary statistics, including median estimates.

Boxplots showing the distribution of the literature estimates are shown in Figure 4 with additional summary statistics in Table 12. The mean WtT emissions rate for Canada is 23.35 gCO_2e/MJ, based on the range of estimates in 43 literature values. The mean and median values are close (median = 23.77 gCO_2e/MJ), indicating that those values together provide a reasonable measure of central tendency.

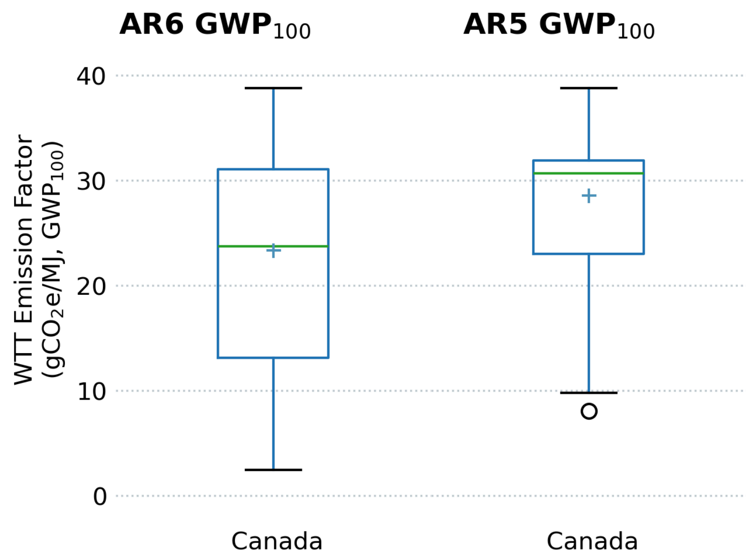
Table 12
Canadian Well-to-Tank carbon intensity (gCO_2e/MJ, GWP_{100})

AR Estimate	count	mean	std	min	25%	50%	75%	max
AR6	43	23.35	11.15	2.48	13.12	23.77	31.06	38.79
AR5	31	28.58	8.12	8.10	23.05	30.71	31.92	38.79

[40] The Shapiro-Wilk test tests the null assumption that the data are normally distributed. $p < 0.05$ indicates that the null hypothesis should be rejected, and the data are not normally distributed.

Figure 4

Canadian Well-to-Tank carbon intensity (gCO_2e/MJ, GWP_{100})



We did not identify any values in the literature that were calculated using the AR6 GWP_{20} factors, or that provided enough information to be converted.

AR5

We identified 31 values that reported LNG WtT emission estimates in AR5 GWP_{100}, no values reported in other AR units could be converted.[41]

The mean estimates for Canada (23.35 gCO_2e/MJ (AR6) vs. 28.58 gCO_2e/MJ (AR5)) differ by 22%, reflecting differences in the methodologies employed for estimating those values in the literature.

Weighted Average Well-to-Tank Carbon Intensity

Data from the World Bank World Integrated Trade Solution (WITS)[42] for imports of "Natural Gas, Liquefied" (HS6 271111) to Canada show low volumes imported, totaling just 230,910 MT in 2023. Around 38.6% of all LNG imported to Canada in 2023 came in the form of low cost (~USD$87/MT) product from Peru, with 29.3% by volume from the United States (~USD$450/MT). LNG Export volumes totaled just 3,852 MT in 2023, with most of that exported to China (81.7%) and Germany (16.8%)

[41] These are values strictly reported in AR5 and do not include conversions of estimates based on other assessment reports
[42] World Bank, WITS, European Union LNG Imports. HS6 271111.
https://wits.worldbank.org/trade/comtrade/en/country/EUN/year/2023/tradeflow/Imports/partner/ALL/product/271111

Table 13

Canadian gross LNG import and export trade by trading partner in 2023

Trade Flow	Partner	Trade Value (000 USD)	% Total	Quantity (MT)	% Total
Import	United States	30,408	61.2%	67,639	29.3%
	Trinidad and Tobago	11,518	23.2%	74,219	32.1%
	Peru	7,763	15.6%	89,034	38.6%
	Other Asia, nes	10	0.0%	17	0.0%
	World	**49,700**	**100.0%**	**230,910**	**100.0%**
Export	China	689	81.3%	3,149	81.7%
	Germany	146	17.2%	646	16.8%
	Korea, Rep.	13	1.5%	56	1.5%
	World	**848**	**100.0%**	**3,852**	**100.0%**

Prior work,[43] submitted to the IMO in support of their GHG LCA rulemaking, estimated emissions from a set of countries that import LNG to the European Union, which included the United States of America and Trinidad and Tobago. That work found the mean value for the U.S. to be 27.40 gCO_2e/MJ (AR6 GWP100) and 12.02 gCO_2e/MJ (AR6 GWP100) for Trinidad and Tobago. That study did not include Peru, and we were unable to identify additional production or emissions resources for Peru. As such, we apply the EU weighted average value from the ISWG-GHG 17/3 study, 21.31 gCO_2e/MJ for LNG volumes from Peru.

Canadian facilities currently produces around 0.316 MTPA LNG from four facilities,[44] although projects currently underway look to expand Canadian export capacity to 2.5 Bcf/d (19.0 MTPA).[45,46]

To compute the weighted emissions, we apply the formula for calculating the arithmetic mean using the study import quantity weight percentages directly, as follows

$$Weighted\ Mean\ WtT\ CO_2e = \sum_{i \in N} p_i WTT_i$$

Where N is the set of importing and producing countries in the study, p is the percent of total LNG imports by mass from country i, and WtT is the WtT carbon intensity for country i.

[43] ISWG-GHG 17/3, Literature review on well-to-tank emissions from liquefied natural gas (LNG) imports to the EU.
[44] https://natural-resources.canada.ca/energy-sources/fossil-fuels/canadian-liquified-natural-gas-projects
[45] https://www.eia.gov/todayinenergy/detail.php?id=64128
[46] https://natural-resources.canada.ca/climate-change/conversion-factors-common-units-used-north-american-cooperation-energy-information

The weighted mean WtT carbon intensity for the AR6 and AR5 GWP_{100} estimates are:

AR6 GWP_{100}: 21.98 gCO_2e/MJ
AR5 GWP_{100}: 25.87 gCO_2e/MJ

The AR5 weighted mean value is 17.6% higher than the weighted mean AR6 value considering all countries in the study and their respective contributions to Canadian LNG. Note that as described in ISWG-GHG 17/3, the sample sizes for some countries are small, and results should be treated accordingly.

Canadian Process Level and Source Category Estimates

This section provides process-level estimates of emissions, in gCO_2e/MJ for the LNG production and supply chain in Canada. The goal was to convert emissions data to AR6 GWP100 for consistency. However, due to limited studies providing detailed CO_2e values or specific CH_4 and N_2O emissions for conversion to AR6, emission factors are aggregated directly from AR6- and AR5-reported values separately.

The "Production++" emission factor covers a combination of similar methodologies and processes in the literature. Some studies provide a detailed breakdown of separate upstream emissions, while others combine these stages for reporting. Variation in how emissions are reported can muddy interpretation of the overall "Production++" emission factor, which may include additional processes in that part of the production chain.

Table 14

Emission Factors Across LNG Supply Chain in Canada (AR6, GWP_{100}, gCO_2e/MJ)

Process	**count**	**mean**	**std**	**min**	**25%**	**50%**	**75%**	**max**
Extraction	3	7.24	4.09	4.64	4.88	5.12	8.54	11.95
Production++	38	8.46	14.58	0.27	2.80	5.08	7.95	86.91
Flaring	1	9.43	-	9.43	9.43	9.43	9.43	9.43
Processing	6	2.84	2.27	0.08	0.92	3.34	4.20	5.71
Storage	1	0.03	-	0.03	0.03	0.03	0.03	0.03
Transport - Pipeline	20	2.25	3.56	0.17	0.50	1.15	1.83	14.46
Transport - Tanker	6	5.26	3.12	2.80	3.28	3.49	7.63	9.53
Liquefaction	26	3.48	3.66	0.32	1.45	2.22	4.01	17.97
Venting	5	2.19	3.02	0.02	0.30	1.22	2.03	7.40
"Other"	8	2.90	2.42	0.89	1.14	1.75	4.34	7.56
WTT combined	43	23.35	11.15	2.48*	13.12	23.77	31.06	38.79

*Low values are associated with natural gas-specific studies, which do not include stages in the LNG supply chain such as liquefaction and additional transit and storage. .

The emission factors presented in Table 14 highlight the variability of GHG intensity across different stages of the LNG supply chain. The 'WtT combined' values have the highest count of datapoints at 43, followed by 'Production++' with 38. This highlights that many studies report aggregated values that encompass multiple up- and/or midstream processes rather than single, well-defined stages. This approach introduces variability due to differences in system boundaries, leading to a broad range of 2.48-38.79 gCO_2e/MJ for the LNG upstream.

The next most frequently reported stages are pipeline transportation and liquefaction, with 20 and 26 values, respectively. This suggests that these two stages are among the most discussed in the literature. Liquefaction, in particular, is a highly energy-intensive process, requiring substantial cooling and compression. The average emissions intensity reported for liquefaction in Canada was 3.48 gCO_2e/MJ, which is substantially lower than the values reported for any nation analyzed in the EU LNG WtT study.[47]

In the EU LNG study, liquefaction was one of the most emissions-intensive stages of the LNG supply chain. For example, U.S. sources reported an average liquefaction emission factor of 12.55 gCO_2e/MJ, more than three times higher than the Canadian average here.[48] As of early 2025, Canada does not yet have any active large-scale liquefaction facilities. Thereby, current Canadian liquefaction values are projections, often making assumptions about the facilities' carbon footprint under proposed low-carbon scenarios. For example, while many permit applications emphasized their commitments to hydropower and renewable grids, integration may not meet expectations (See: Background & Purpose).

Even with the inclusion of natural gas-specific values that exclude stages like liquefaction, additional transit and storage emissions, and assumptions based on renewable energy and low-carbon scenarios for proposed Canadian LNG facilities, the average WtT values for Canadian LNG were estimated to be 23.35 gCO2e/MJ (AR6 GWP_{100}).

There were fewer emission factors for various WtT stages when reporting under AR5, with most values being either aggregated 'WtT Combined' or for liquefaction. The WtT average is higher reported under AR5 than AR6 (28.58 vs 23.35 gCO_2e/MJ), which could be explained by the AR5 studies utilizing higher GWP100 weightings (e.g. 30-34). Liquefaction averages were still projected to have low emissions intensity compared to other nations, with a value for the proposed 'Ksi Lisims' facility estimated to be as low as 0.43 g CO_2e/MJ once electrified with renewables.

[47] https://www.transportenvironment.org/uploads/files/WTT_CO2e_LNG_Imports_TE.pdf
[48] https://www.transportenvironment.org/uploads/files/WTT_CO2e_LNG_Imports_TE.pdf

Figure 5

Emission Factors Across LNG Supply Chain in Canada (AR6, GWP_{100}, gCO_2e/MJ)

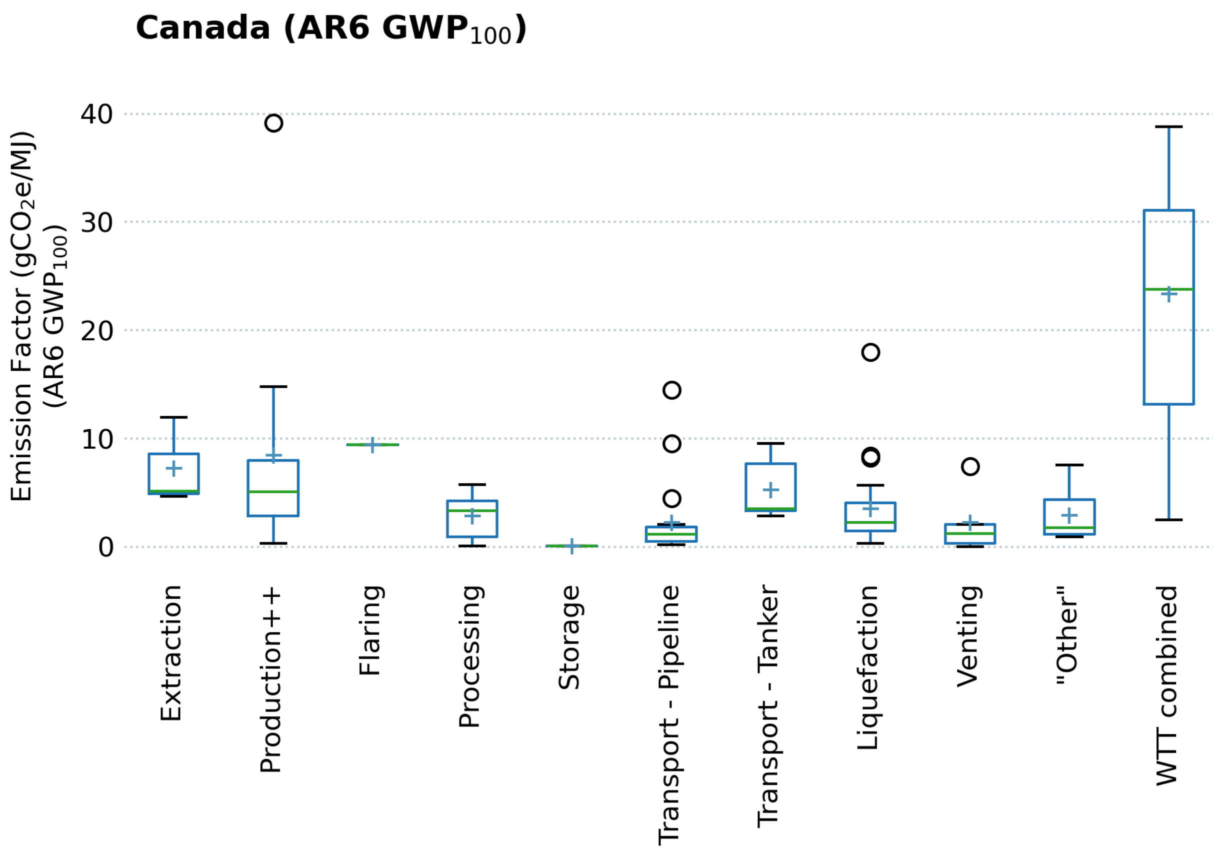


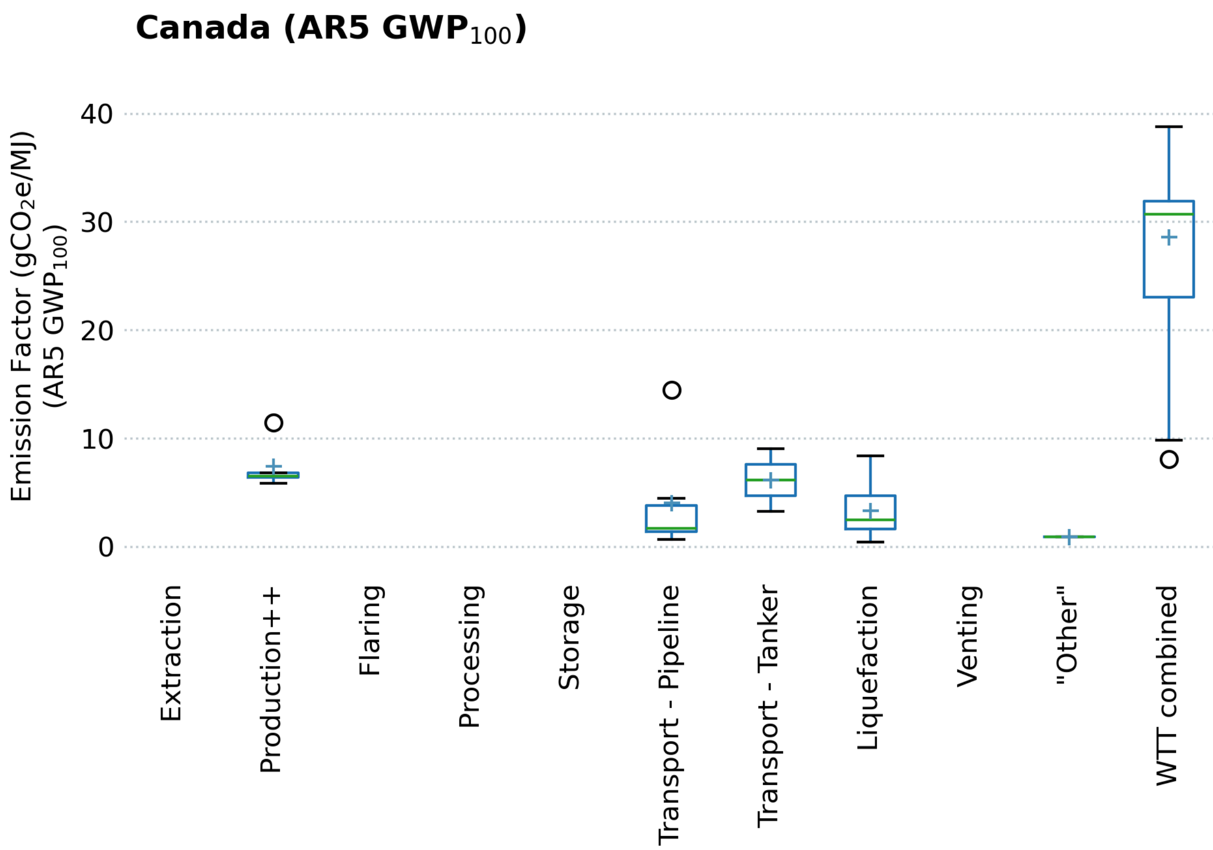
Table 15

Emission Factors Across LNG Supply Chain in Canada (AR5, GWP_{100}, gCO_2e/MJ)

Process	count	mean	std	min	25%	50%	75%	max
Extraction	0	-	-	-	-	-	-	-
Production++	5	7.40	2.29	5.86	6.40	6.48	6.82	11.45
Flaring	0	-	-	-	-	-	-	-
Processing	0	-	-	-	-	-	-	-
Storage	0	-	-	-	-	-	-	-
Transport - Pipeline	6	4.05	5.26	0.68	1.37	1.69	3.81	14.46
Transport - Tanker	2	6.12	4.09	3.22	-	-	-	9.01
Liquefaction	14	3.29	2.57	0.43	1.62	2.48	4.70	8.35
Venting	0	-	-	-	-	-	-	-
"Other"	1	0.89	-	0.89	0.89	0.89	0.89	0.89
WTT combined	31	28.58	8.12	8.10	23.05	30.71	31.92	38.79

Figure 6

Emission Factors Across LNG Supply Chain in Canada (AR5, GWP_{100}, gCO_2e/MJ)



Vessel Activity Profiles

We identified 15 LNG vessels around Vancouver and the Gulf Islands based on 2023 AIS data from Marine Cadastre,[49] and vessel characteristics data from SeaWeb.[50] The majority of vessels (10) are from Canada, followed by 3 from Japan, 1 from Liberia, and 1 from the Marshall Islands. Of the vessels, 6 are vehicle passenger/Ro-Ro ships, 4 are Ro-Ro cargo ships, 4 are vehicle carriers, and 1 is a crude oil tanker. All of the Canadian vessels are Ro-Ro vessels, with 6 being vehicle passenger/Ro-Ro ships and 4 Ro-Ro cargo ships. The Japanese and Liberian ships are vehicle carriers and the Marshall Islands ship is a crude oil tanker.

Almost half (7) of the vessels are relatively new (<5 years old), 6 are 5-15 years old, and 2 vessels are around 30 years old. The ships have a range of main engine power of 4,440-16,695 KW with an average of 9,850 KW, and a range of auxiliary engine power of 374-1,833 KW with an average of 1,006 KW. Deadweights range from 13,610 to 113,306,

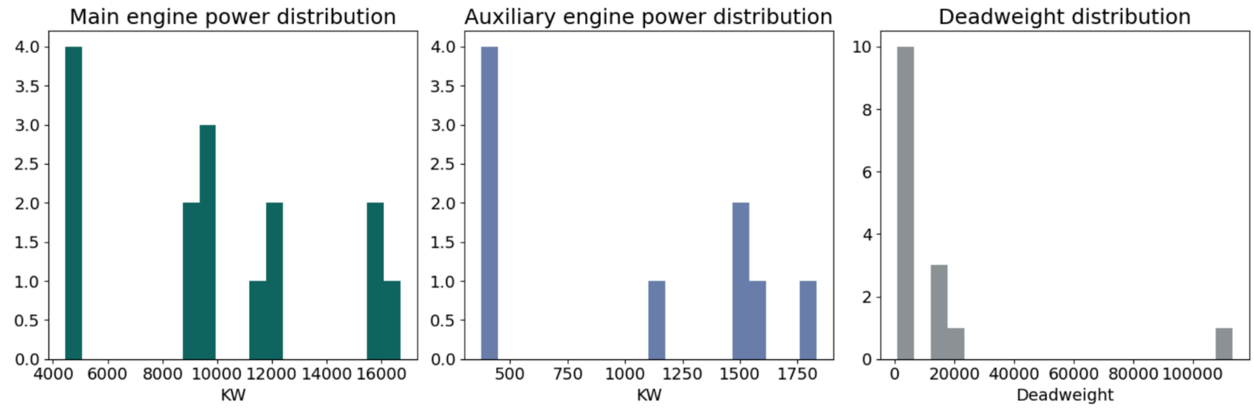
[49] https://hub.marinecadastre.gov/pages/vesseltraffic. We are aware of vessel activity around Montreal, but did not observe those vessels in the available data

[50] https://maritime.ihs.com

averaging 809. The crude oil tanker has the highest deadweight, followed by the vehicle carriers. Distributions of vessel engine power and deadweight are displayed in Figure 7.

Figure 7

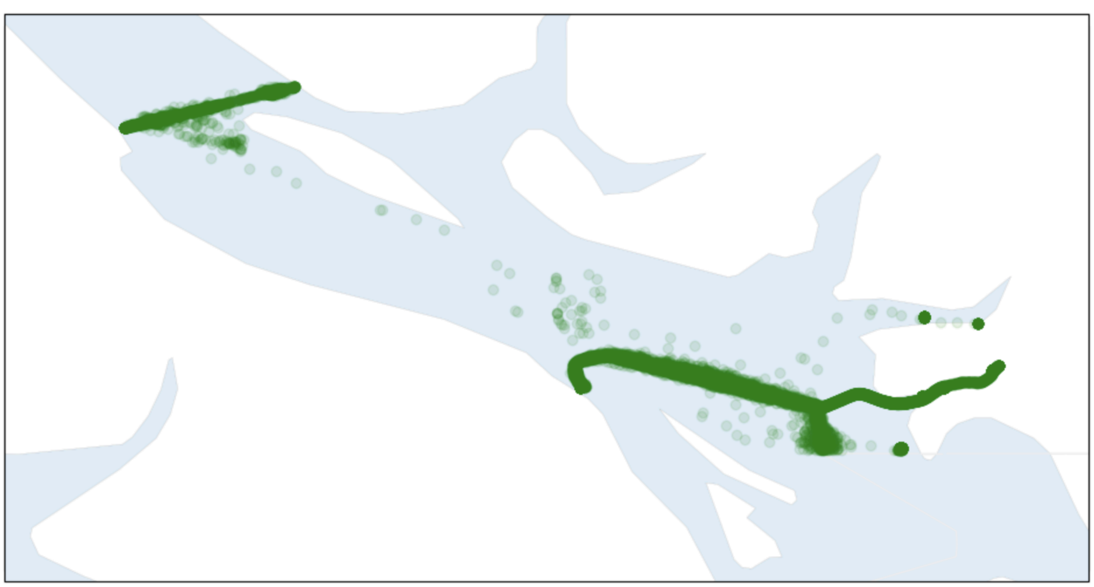
LNG Vessel Engine Power and Deadweight Distributions



Vessel activity is concentrated mainly between the Fortis BC Tilbury bunkering location and Mount Hayes Liquefaction Facility to the west, shown in Figure 8. There is also a fair amount of movement between these facilities and the Fortis BC truck-to-ship bunkering location in the northwest part of this region near Courtenay. The vessels tended to spend 12-13 hours at LNG facilities before moving on. Activity around LNG facilities slightly increased from January to June and then remained relatively consistent throughout the remainder of the year. Although LNG vessels have been identified, these results are based on only 15 vessels. More information is needed to draw robust conclusions.

Figure 8

LNG Vessel Activity in the Vancouver Area



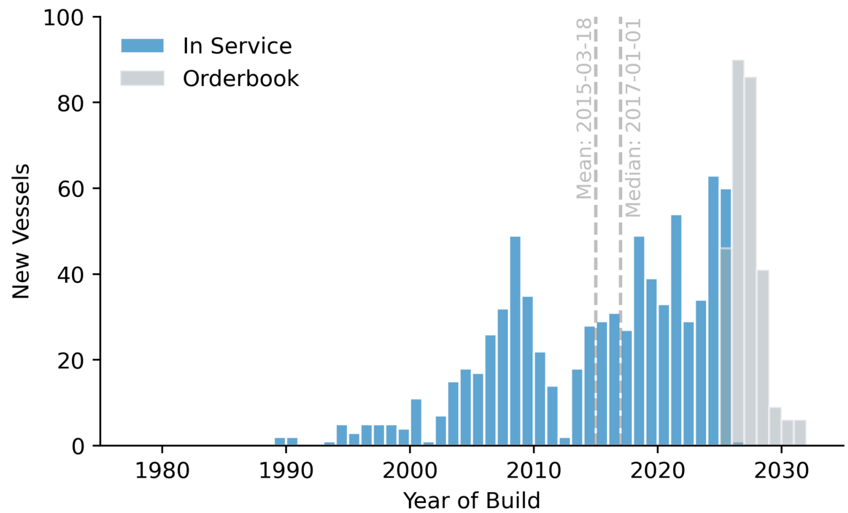
Global LNG Tanker Fleet

As shown in Table 13, Canadian LNG imports and exports are limited. We did not observe any LNG tankers for import or export of LNG in the available AIS data set, and so this analysis instead presents an overview and analysis of the existing and orderbook LNG tanker fleet, with a forward view towards future LNG import and export activity.

The global LNG tanker fleet has seen three main cycles of investment, from 1990 to 2001, from 2002 through 2011, and post-2020. These cycles correspond with expansion in oil and gas exploration and production, and major macroeconomic cycles. There are currently 776 LNG tanker vessels in service or launched. The orderbook includes another 284 vessels, a 36.6% increase over the existing fleet. The current orderbook (vessels to be delivered in 2025 or later) shows more new vessels delivered per year in the next few years than in any year prior, indicating that the industry is in a significant investment cycle in LNG tankers for carrying LNG products. Of the in-service LNG tanker vessels, the mean year of build in 2015, and the median is 2017, reflecting increased investment in the fleet in recent years.

Figure 9

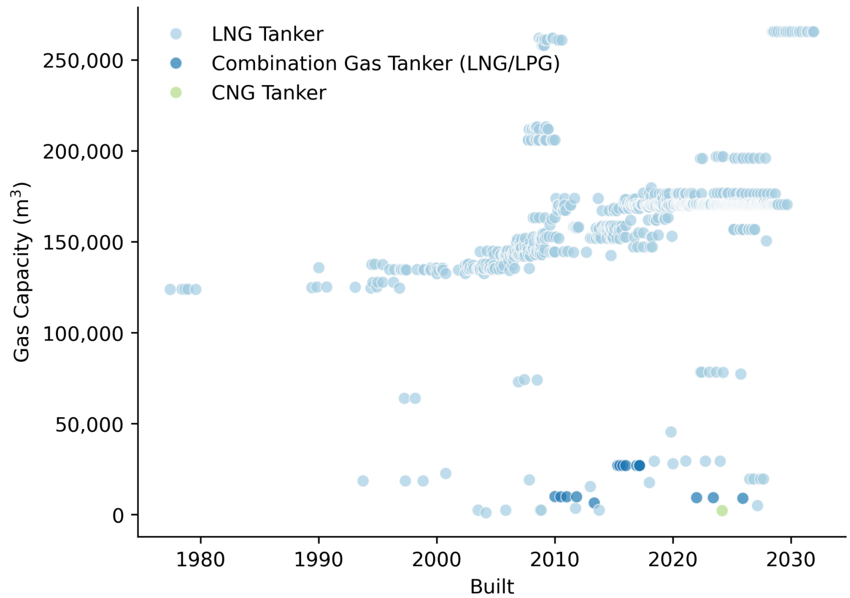
Global LNG Fleet Vessels' Year of Build



The data show a trend towards increasingly larger vessels, with greater gas carrying capacity in recent years. From 1990 to 2010, most LNG takers were between 125,000 m^3 and 150,000 m^3. Between 2020 and 2025, of the 319 vessels built during that period, the mean gas capacity was 166,160 m^3, the median was 170,560 m^3, and the largest was 196,883 m^3. The current orderbook shows 24 vessels on order with a gas capacity of 265,580 m^3.

Figure 10

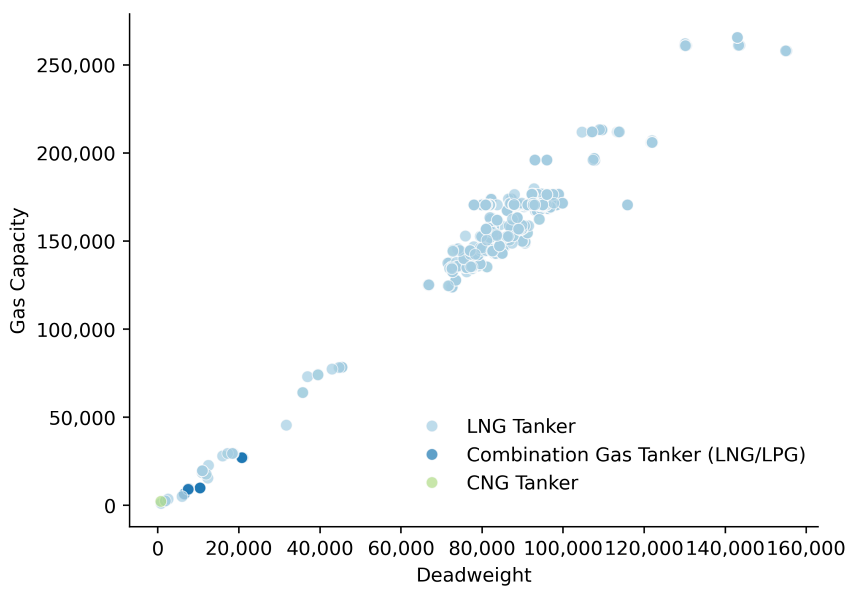
Global LNG Fleet Vessels' Gas Capacity over Time



Gas capacity and vessel deadweight are tightly coupled, in a positive and linear relationship, where for every additional DWT, LNG tankers can generally carry an additional 1.85 m^3 of LNG (adj. $R^2 = 0.996$, $p < 0.001$).

Figure 11

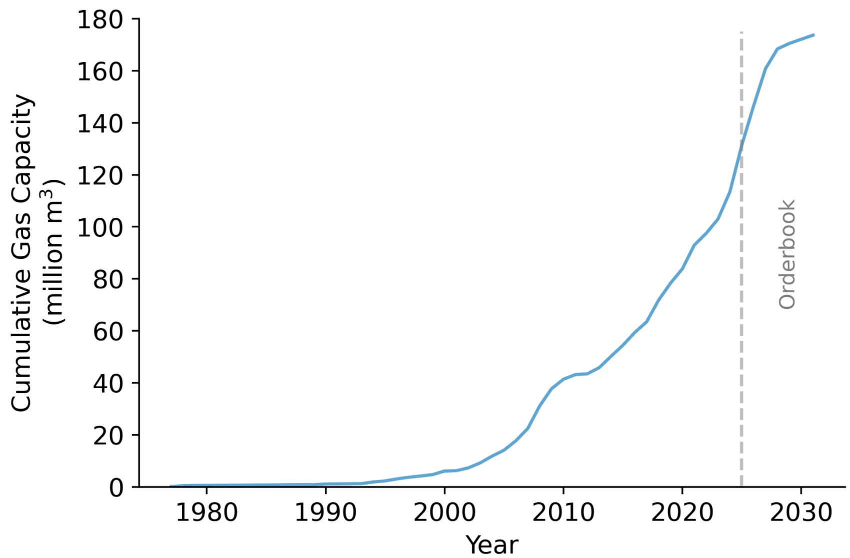
Global LNG Fleet Vessels' Gas Capacity and Deadweight Tonnage



As the individual carrying capacity of LNG tankers has increased over time, as has the capacity of the fleet to carry LNG. The data show rapid growth since 2000, with a post-Great Recession slow-down in 2010 - 2012. In 2009 the gas carrying capacity of the fleet was 37.77 million m^3 of LNG, which grew nearly 3.5x to 131.30 million m^3 in 2025. The current order book is projected to increase capacity 1.32x to 173.66 million m^3 LNG by 2031, though that number will likely increase as new orders are added.

Figure 12

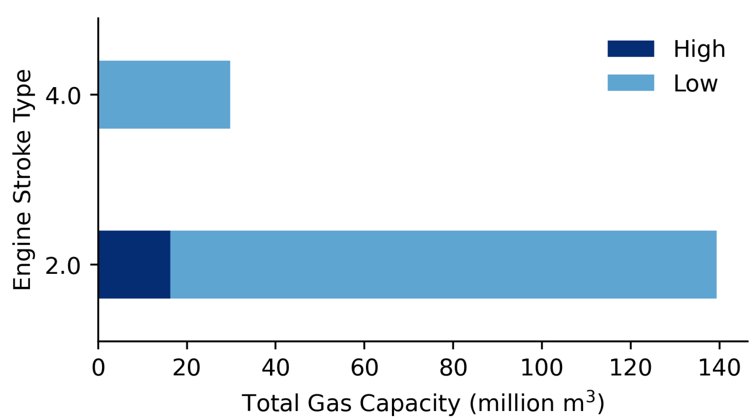
Global LNG Fleet Vessels' Historical and Orderbook Future Gas Capacity



Including the current orderbook, 1016 vessels list "Fuel Type 1" as either "Gas Boil Off" (215 vessels) or "Lng" [sic.] (801 vessels), and 58 vessels list "Fuel Type 1" as either 'Distillate Fuel', with a single vessel reporting type not known. This means that the majority (94.5%) of LNG tankers operating today, or on the orderbook, are built to operate directly on LNG or boil off gas as their primary fuel.

Figure 13

Global LNG Fleet Vessels' Engine Type (2- vs 4-stroke, high- vs low-pressure)



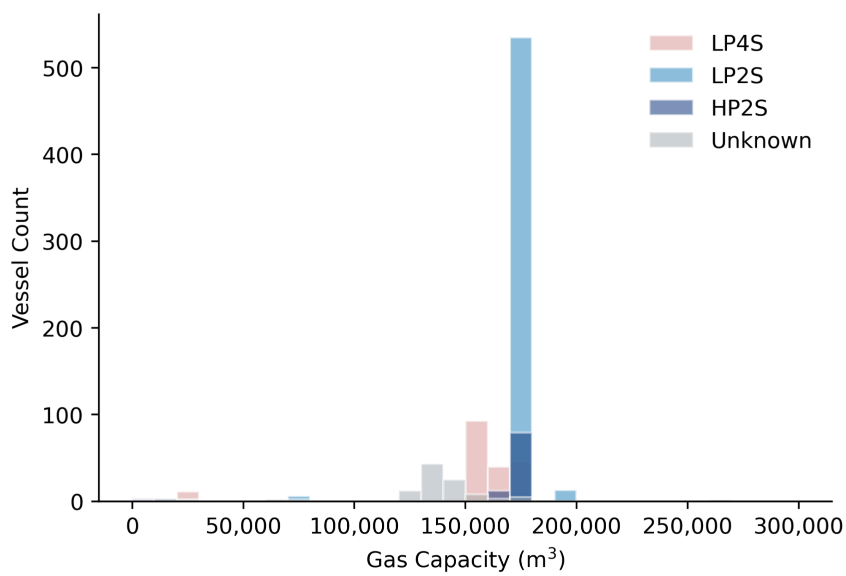
When looking at total gas capacity, for the engines where we were able to identify the stroke type and cycle,[51] the data show that the vast majority of carrying capacity is on vessels with low pressure 2-stroke engines (72.7%), followed by low pressure 4-stroke engines (17.6%) and then high pressure 2-stroke engines (9.6%).

As summarized and discussed in prior research,[52] marine gas engines are designed as either a lean-burn spark ignition (LBSI) configuration that uses a 4-stroke (4S) Otto cycle, or in a dual fuel (DF) configuration. Dual fuel engines may be either low pressure Otto-cycle + Diesel cycle, or high-pressure Diesel cycle, 2-stroke (2S) or 4S.

Marine engines that run on an Otto cycle can have high levels of methane emissions in the stack from unburned methane from the combustion chamber, so-called methane slip. Data from the Green-Ray project in the EU[53] indicates that duty-cycle weighted Tank-to-Wake (TTW) emissions from Otto-Cycle engines (e.g. LBSI, LP2S, LP4S) can vary from 2.0 - 13.5 gCH_4/kWh (16.56 - 111.75 gCO_2e/MJ), around 10x to 45x higher than emissions from high-pressure dual fuel (HPDF) 2S diesel cycle engines, which range from 0.2 - 0.3 gCH_4/kWh (1.66 - 2.48 gCO_2e/MJ) consumed.

Figure 14

Global LNG Fleet Vessels' Count by Carrier Sizes



Consequently, for the global LNG tanker fleet, around 90.4% of the total gas carrying capacity is on vessels with engine exhaust methane slip emissions that could be upwards

[51] Engine model and stroke was provided by SeaWeb. Model and stroke were then compared to published engine manufacturer specifications to determine the engine cycle and pressure. We were able to determine cycle and pressure for engines from MAN B&W, Kawasaki, MaK, Wartsila, and WinGD. We were not able to determine cycle and pressure for Mitsubishi LNG engines, which accounted for 8.4% of the engines in the global LNG tanker fleet.
[52] E.g. https://theicct.org/wp-content/uploads/2023/10/Options-for-Reducing-Methane-Emissions-from-New-and-Existing-LNG-Fueled-Ships-FINAL-926.pdf
[53] https://greenray-project.eu/wp-content/uploads/2023/04/D1.1_Review_of_methane_slip_from_LNG_engines.pdf

of 10x higher than emissions from the lowest slip engines (HPDF - 2S). Among the most common carrier size category, 170,000 - 180,000 m^3, over 500 vessels are LPDF - 2S. Given methane's potency as a GHG, and the rapid growth in the LNG tanker fleet, this has significant implications for exhaust emissions from LNG-carrying vessels.

Conclusions

This work presents emission estimates from a wide range of sources to characterize emissions from the Canadian LNG supply chain. Comprehensive data from the Canadian Greenhouse Gas Reporting program show that flaring emissions are predominately CO_2, whereas leakage and venting emissions in the LNG chain are dominated by methane (97.83% and 89.60%, respectively). Province-level estimates of GHG emissions associated with early upstream stages in the LNG chain (production and extraction, distribution) show a high degree of variability, depending on the extraction methods and co-located oil and gas extraction activity. Taking all Canadian production into account, the national average for production emissions reported in the GHGRP is 7.44 gCO_2e/MJ. This value is reasonably aligned with independent upstream estimates derived from satellite observations (8.88 gCO_2e/MJ) and this analysis of the available literature (8.46 gCO_2e/MJ), indicating that the results of this analysis are robust and independently verified.

Based on the current mix of LNG in Canada, taking into account contributions including imports, the weighted mean WtT carbon intensity GWP_{100} estimates are:

AR6 GWP_{100}: 21.98 gCO_2e/MJ
AR5 GWP_{100}: 25.87 gCO_2e/MJ

LNG vessel activity is currently limited in and around Canada. We found limited LNG vessel activity in the publicly available AIS data set in the Salish Sea. LNG tanker activity was not observed, which is intuitive given the small volumes of LNG imports and exports currently reported in Canada.

Analysis of the global LNG tanker fleet shows that around 90% of the LNG carrying capacity of the global fleet use low pressure dual fuel or lean-burn spark ignition engines susceptible to methane slip. Emissions from those engines can be more than 10x higher than high pressure dual fuel engines. This means that much of the LNG being carried could have methane stack emissions upward of 2.0 gCH_4/kWh (59.6 gCO_2e/kWh, or 15.56 gCO_2e/MJ, AR6 GWP_{100}) in addition to emissions of CO_2 from combustion.

Canada is set to increase production and export capacity of LNG dramatically, the vessels that will move Canadian exported energy can also be significant contributors to the life cycle emissions of the delivered product.

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