Assessing Emissions from LNG Supply and Abatement Options

International Energy Agency

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Introduction

Around 550 billion cubic metres (bcm) of natural gas were exported as liquefied natural gas (LNG) in 2024, just under 15% of global natural gas consumption. A further 500 bcm of natural gas were transported through pipelines. Global LNG supply has grown faster than overall natural gas demand in recent years. This trend is set to continue with the arrival of nearly 300 bcm of new annual LNG supply capacity between 2025 and 2030.

Previous International Energy Agency (IEA) analysis has highlighted that the greenhouse gas emissions associated with extracting, processing and transporting natural gas are, on average, around 12 grammes of CO_2 equivalent (g CO_2-eq) per megajoule (MJ). About 55 g CO_2/MJ are emitted when natural gas is combusted and so the process of extracting natural gas and bringing it to consumers represents 15% of its full life-cycle emissions.

There is a broad range of emissions from extracting, processing and transporting natural gas, which vary by more than five-fold across different geographies. Given the high energy requirements to liquefy and transport gas over long distances, LNG tends to have higher emissions than natural gas that is produced close to where it is consumed (emissions from gas transported by pipeline also vary widely, often according to the distances involved).

Several importing countries are starting to assess the emissions intensity of oil and gas imports, for example, through the EU regulation on methane emissions and the Coalition for LNG Emissions Abatement toward Net-zero (CLEAN). There has been a large increase in the availability and reporting of emissions data from the natural gas value chain in recent years. However, estimates are still subject to a high degree of uncertainty.

This interim report estimates emissions from LNG supply today, based on the latest and best available data including those from scientific studies and measurement campaigns. It covers upstream production and processing of natural gas, pipeline transmission from processing facilities to export terminals, liquefaction processes, shipping and regasification at import terminals. It considers methane emissions, flaring, naturally occurring sources of CO_2 and energy consumption from across the supply chain. It also explores mitigation options, covering pathways to reduce methane emissions and flaring, improving efficiency across all stages of the LNG chain, electrifying key processes, and deploying carbon capture, utilisation and storage (CCUS). This report will feed into a report in 2026 providing a toolkit for LNG producers to reduce emissions.

This report does not assess emissions from natural gas distribution, from end-use combustion, avoided or additional emissions from switching to or from LNG from other fuels, or emissions associated with other potential sources of LNG (e.g. biomethane or “e-methane”).

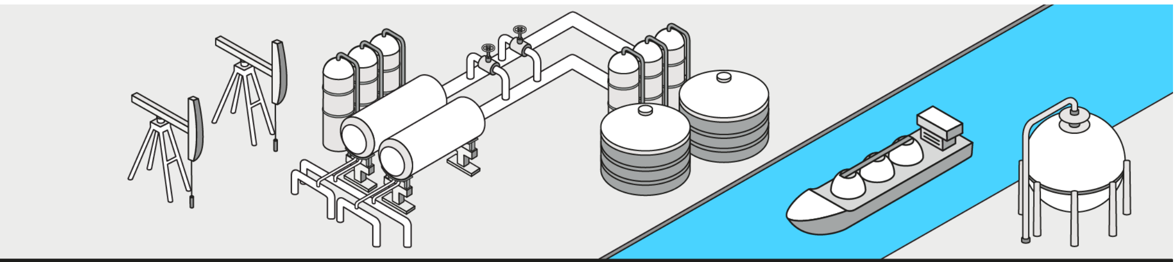
Emissions from liquefied natural gas

Summary

This report estimates emissions along the LNG supply chain, covering production, processing, transmission, liquefaction, shipping and regasification. The emissions associated with exploration, onward transport after regasification, and combustion of the natural gas, are excluded.

We analysed around 350 upstream assets (in 22 countries), 45 liquefaction terminals, and 220 regasification terminals (in 50 countries), and tracked the voyages of more than 750 ships carrying LNG making around 7 000 round-trip journeys per year. We compiled public and proprietary data on all these assets to form a detailed supply chain assessment that covers the entire journey, for all deliveries of LNG, from the wellhead, through production and processing, transmission to liquefaction sites, shipping and regasification (Figure 1).

Figure 1 Global average emissions from LNG supply by part of the supply chain, 2024



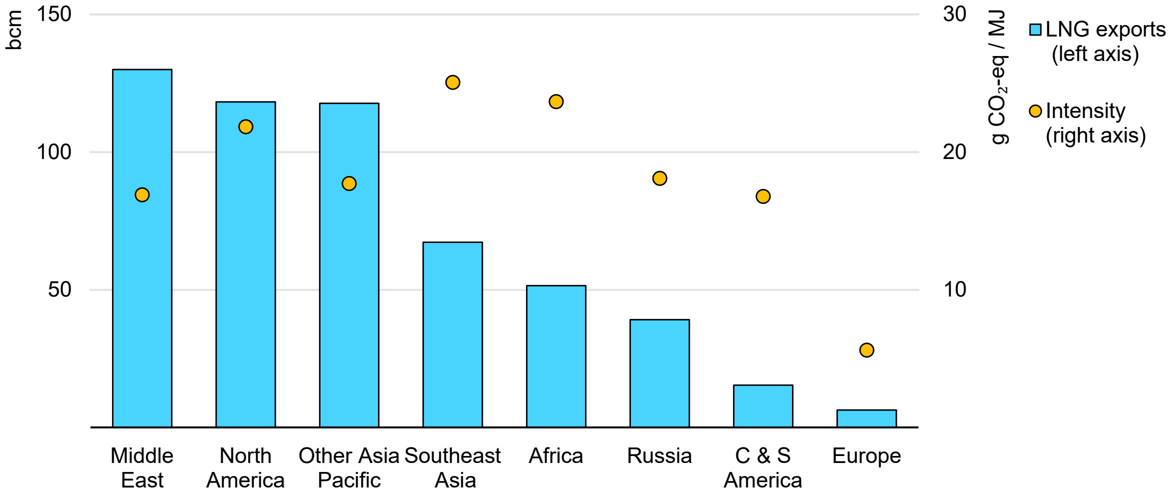
GLOBAL AVERAGE EMISSIONS INTENSITY (g CO_2-eq/MJ)		PRODUCTION, PROCESSING AND TRANSMISSION	LIQUEFACTION	SHIPPING	REGASIFICATION
19.5	% total GHG emissions	47%	33%	18%	1%
14.0	% of supply chain CO_2 emissions	34%	43%	22%	1%
5.5	% of supply chain CH_4 emissions	80%	9%	10%	2%
	Key levers to lower GHG emissions	• Leak detection and repair • Electrification	• Electrification • Carbon capture, utilisation and storage	• Low-emissions fuels • Slow steaming	• Low-emissions vaporisers • Cold energy recovery

Notes: CH_4 = methane. GHG = Greenhouse gas. Production, processing and transmission includes exploration, production, gathering, processing and transmission to liquefaction. One tonne of methane is taken to be equivalent to 30 tonnes of carbon dioxide (t CO_2) based on a 100-year global warming potential (GWP) (IPCC [2021], Sixth Assessment Report). Emissions intensities are based on global average figures, but intensities vary across different parts of the supply chain and by country and basin. Percentages may not add up to 100% due to rounding.

Our analysis estimates total GHG emissions from the LNG supply chain are around 350 million tonnes of carbon dioxide equivalent (Mt CO_2-eq) (this excludes emissions from combustion of the natural gas at the point of use). Around 70% of this is in the form of CO_2 emissions which are either combusted or vented, and the remaining 30% is methane that escapes, unburnt, into the atmosphere. The main source of methane is leakage during upstream production and processing, while the main source of CO_2 emissions come from the large energy requirements needed to compress and liquefy natural gas at LNG export terminals.

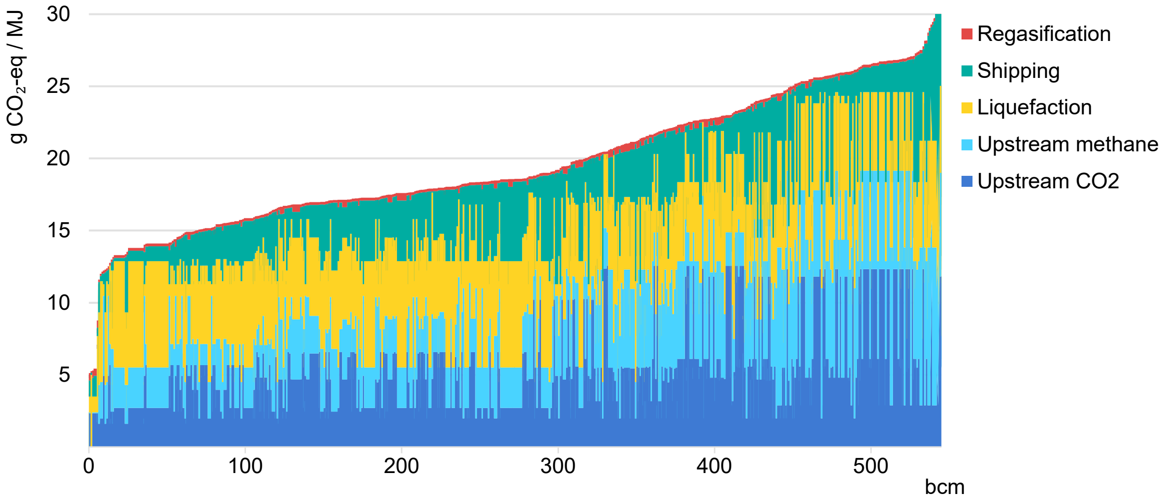
Globally, the average GHG emissions intensity of delivered LNG is just under 20 g CO_2-eq/MJ, compared with an average of 12 g CO_2/MJ for natural gas supply overall. This average masks a wide range, with considerable variations across different geographies and supply routes. The emissions GHG intensity of LNG is more than 26 g CO_2/MJ for some LNG exporters in Africa and Southeast Asia and less than 6 g CO_2/MJ in Norway (Figure 2). The variation is explained primarily by the amount of methane emissions associated with the natural gas that goes into LNG terminals as well as the energy use and level of CO_2 venting associated with processing this natural gas. Some LNG supply routes also require lengthy journeys or use less-efficient ships (Figure 3).

Figure 2 LNG exports and regional average GHG emissions intensity of LNG exports, 2024



Notes: bcm = billion cubic metres; g CO_2-eq/MJ = grammes of carbon dioxide equivalent per megajoule; C & S America = Central and South America. Emissions intensity includes all CO_2 and methane emissions from production, processing, transmission, liquefaction, shipping and regasification divided by total LNG exports from that region. One tonne of methane is taken to be equivalent to 30 t CO_2 based on a 100-year GWP (IPCC [2021], Sixth Assessment Report).

Figure 3 Spectrum of GHG emissions intensity from the LNG supply chain, 2024



Notes: Each data point is the estimated weighted average emissions intensity of a single supply route linking an LNG export terminal to a regasification terminal. One tonne of methane is taken to be equivalent to 30 t CO_2 based on a 100-year GWP (IPCC [2021], Sixth Assessment Report).

Box 1 How do IEA estimates of LNG emissions compare with others?

A wide range of LNG emissions intensities have been reported in the literature, largely driven by differing process assumptions, system boundaries and allocation methods. This is partly due to the inherent complexity of the LNG supply chain, as well as the wide range of methods available for measuring or estimating GHG emissions.

The choice of splitting upstream methane emissions between the oil and natural gas that are co-produced at a given field (either in energy terms or based on economic value) or simply allocating them to natural gas (usually in volume terms) has major implications for overall intensities. Our estimates allocate upstream methane emissions in energy terms to both oil and gas.

There are also different ways to express a tonne (t) of methane in carbon dioxide equivalent (CO_2-eq) terms. The most common approach is to use the global warming potential (GWP). However, different conversion factors can be applied, which have a major impact on the assumed potency of methane. Some consider the impact of methane over a 20-year time frame, with 1 t of methane usually taken to be equivalent to 82.5 t CO_2-eq. Others look at its impact over a 100-year time frame, with 1 t of methane equivalent usually taken to be around 30 t CO_2-eq.[1]

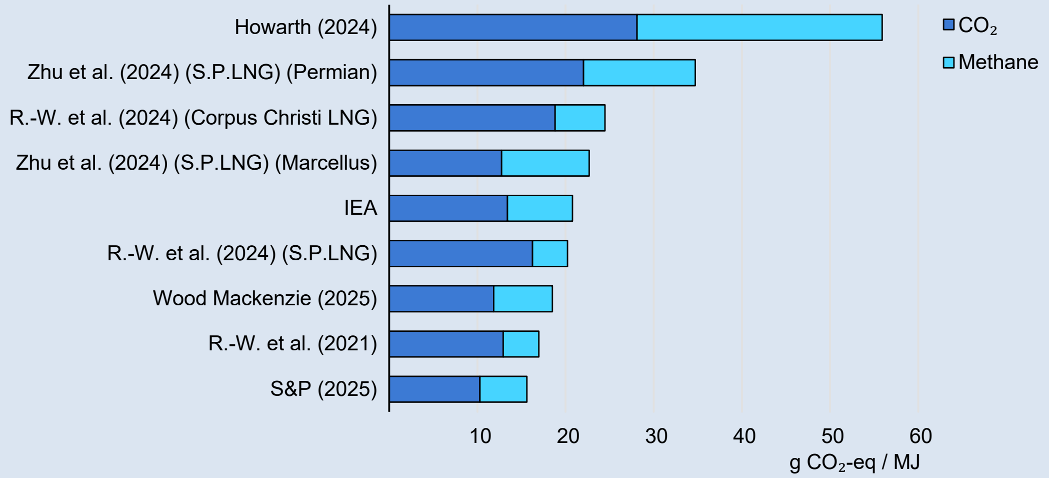
[1] Some authors use conversion factors taken from older Intergovernmental Panel on Climate Change reports: for example, Roman White et al. (2021), LNG Supply Chains, used a 100-year GWP value of 36 based on IPCC (2014), AR5 Synthesis Report: Climate Change 2014.

The choice of the most appropriate time frame depends on the emissions scenario in question (e.g. if or when there is a peak in the global temperature rise) and can be subjective. Our estimates consider 1 t of methane to be equivalent to 30 t CO_2.

When comparing estimates for a specific trade route (United States to Europe), published estimates for emissions from production to regasification vary from 16 g CO_2-eq/MJ to 56 g CO_2-eq/MJ (Figure 4). When methane and CO_2 emissions are taken into account, IEA estimates of LNG GHG intensities are broadly within the range of other available estimates.

Methane emissions vary more than tenfold among different sources, and CO_2 emissions by a factor of nearly threefold. For example, analysis of methane emitted from gas liquefied at the Sabine Pass and Corpus Christi liquefaction facilities found a total methane emissions intensity below 0.5%, and other analysis of LNG sourced from the Permian basin found an intensity of more than 2%.[2] The average methane emissions intensity for US to Europe LNG trade in our analysis is around 1.4% (details of the data sources and assumptions used to derive our estimates of emissions intensities are available in the technical annex).

Figure 4 Emissions from producing and transporting LNG from the United States to Europe reported by different sources



Notes: Basin providing feed gas or specific US LNG terminal is in brackets if specified, otherwise estimate is average of all US LNG exports to Europe (S&P (2025) does not specify the import location). R.-W. et al. = Roman-White et al. S.P.LNG = Sabine Pass LNG terminal. Horizontal axis is per unit of natural gas delivered at the regasification terminal. One tonne of methane is considered to be equivalent to 30 t CO_2 for all authors. Excludes emissions from end-use gas combustion.

Source: IEA analysis based from Roman-White et al. (2021), LNG Supply Chains; Howarth (2024), The greenhouse gas footprint of liquefied natural gas (LNG) exported from the United States; Zhu et al. (2024), Geospatial Life Cycle Analysis of Greenhouse Gas Emissions from US Liquefied Natural Gas Supply Chains; S&P Global Commodity Insights (2025) ©2025 by S&P Global Inc., Major New US Industry at a Crossroads – Phase 2; Wood Mackenzie (2025), US LNG full lifecycle emissions delivered to Europe are 48% of the coal equivalent.

[2] The total methane emissions intensity is calculated here as upstream and downstream methane emissions divided by LNG delivered to the regasification terminal in energy terms, assuming methane has an energy density of 55 MJ per kilogramme (kg).

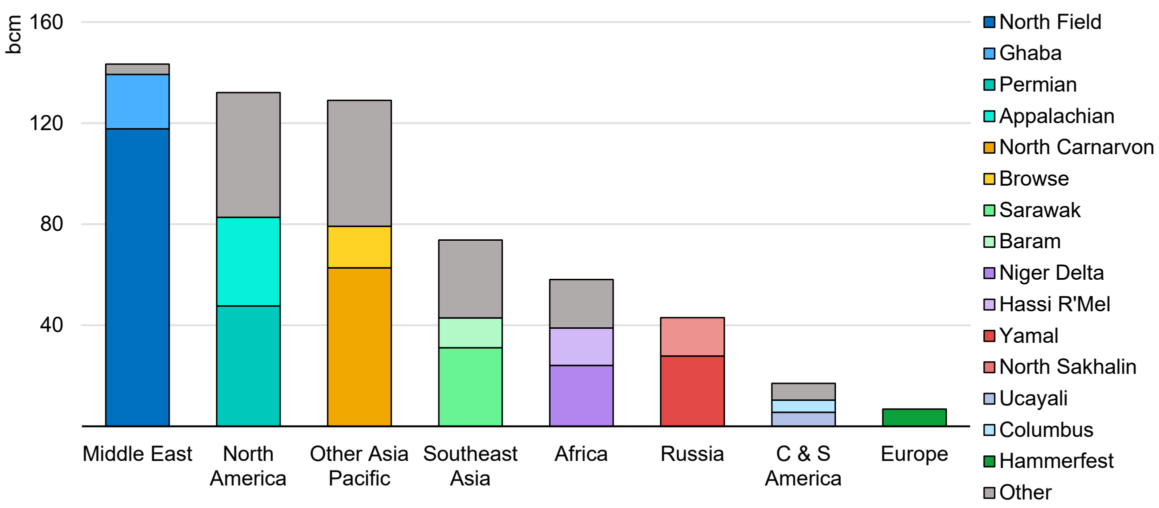
Production, processing and transmission

Linking liquefied natural gas terminals to upstream assets

About 550 bcm of LNG were exported globally in 2024 from 22 countries. Around 600 bcm of natural gas (usually called the “feed gas”) was produced for this given consumption during liquefaction and other losses along the supply chain. There are around 40 upstream basins that produce feed gas for LNG, flowing through multiple gathering stations, processing plants, boosting facilities and pipelines, to enter around 140 liquefaction trains that are in service globally.

In some cases, it is simple to link individual upstream assets to an individual LNG export terminal, for example if there is a single physical connection between them. This is the case in Qatar, for example, where the feed gas comes from a single gas field, the North Field, and most of the gas is exported as LNG (Figure 5). However, this calculation is often much more complicated. In the United States, for example, many LNG terminals receive natural gas from a pipeline network that has co-mingled natural gas from multiple upstream assets and processing facilities. In some cases, producer supply agreements can shed light on the feed gas that is produced, treated and transported before liquefaction, as do company reports and production data; nevertheless, different approaches can still be used to trace the origin of feed gas (Box 2). The approach adopted in this work is described in the technical annex.

Figure 5 Estimated feed gas volumes by upstream basin flowing to LNG terminals (2024)



Notes: Volumes shown are feed gas, which are greater than volumes exported for LNG given the use of feed gas during liquefaction and other losses; C & S America = Central and South America.

Source: IEA estimates based on data from U.S. Energy Information Administration (2025), Federal Energy Regulatory Commission (2024), IEA (2024) World Energy Outlook 2024, Rystad Energy (2025), S&P Global, (2025), S&P Capital IQ, April 2025, and company reporting.

Box 2 Traceability in natural gas supply chains

There has been a surge of interest in understanding how to link specific sources of feed gas flowing into LNG terminals since the introduction of the EU Methane Regulation in 2024. This regulation states that importers of oil and gas must obtain quality data on the origins and associated emissions of imports to ensure they meet EU domestic standards for monitoring, reporting and verification in 2027. This requires a credible and transparent chain of custody model to track emissions across the supply chain that allows users to compare different sources of natural gas and for emissions disclosures to be independently verified.

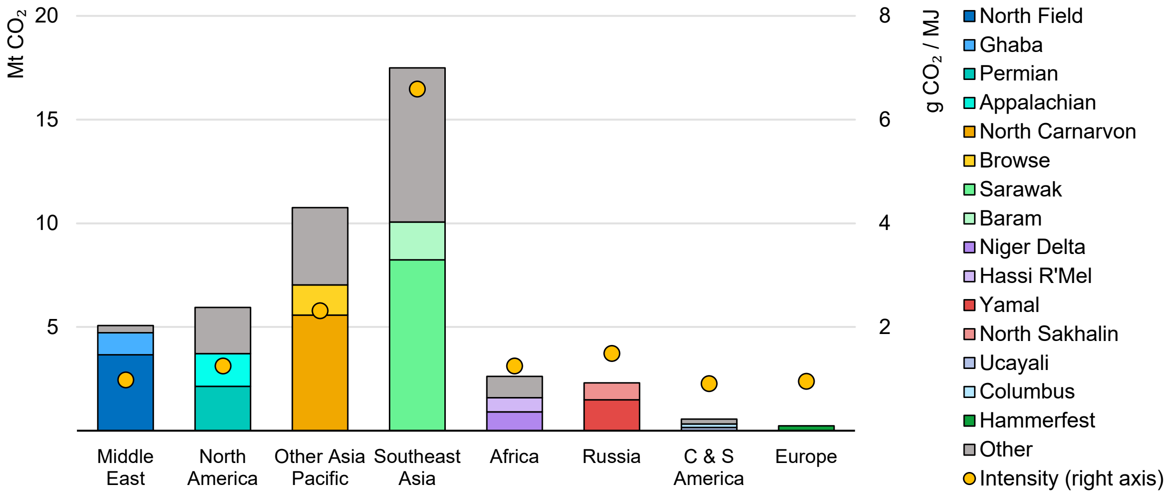
No such system has yet been implemented for LNG or natural gas markets. Existing resources such as the “chain of custody” models established by International Sustainability and Carbon Certification and the International Organisation for Standardisation can inform these efforts and possible approaches for LNG include the following (in practice stakeholders may look to use a hybrid of these):

- **Mass balance** models, which track the ratio of fuel in a system that meets a certain emissions standard to the total amount of fuel through detailed bookkeeping at every stage in the supply chain. These models allow for flexibility in sourcing and may or may not involve the trading of certificates.
- **Book-and-claim** models, which allow producers of gas that meets a certain standard to obtain certificates. Buyers may purchase these certificates to claim the receipt of "certified gas" even if the physical gas they receive is not certified.
- **Trace-and-claim** models, which assign a digital identification to volumes of gas that can be traced to a specific producer and facility through sale and purchase agreements. These can provide specific emissions levels for that volume of gas. This system relies on a robust and well-maintained data registry of profiles and certificates in standardised formats to store and track the movement of gas through the supply chain.
- **Physical segregation**, which relies on dedicated infrastructure to keep “certified gas” separate from “non-certified” gas. This is usually the costliest approach (and often impractical) except where dedicated infrastructure already exists.

CO_2 emissions from energy use

Extracting oil and gas from the subsurface requires large amounts of energy to power drilling rigs, pumps and other process equipment, and to maintain the drilling fluids at the desired temperature and pressure. A continuous supply of fuel to provide the energy required for upstream oil and gas operations is essential. The fuel used is typically diesel before production has started (i.e. during the drilling and development stage), and natural gas or electricity during the production phase. After extraction, natural gas undergoes separation to drop out natural gas liquids, dehydration to make it suitable for transport, and treatment to remove impurities such as CO_2 and hydrogen sulphide. There are also CO_2 emissions from natural gas transmission (i.e. the transport of gas from processing facilities to LNG export terminals), mainly from energy use in compressors. We estimate that the global average emissions intensity of the energy used in production, processing and transmission is 2.1 g CO_2/MJ (Figure 6), although this figure varies markedly between regions given differences in the production-type, size and maturity of fields providing feed gas, the level of impurities in extracted gas, and the distances that gas need to travel to LNG export terminals.

Figure 6 CO_2 emissions from energy use from production, processing and transmission for LNG feed gas and regional average CO_2 emissions intensities, 2024



Note: C & S America = Central and South America.

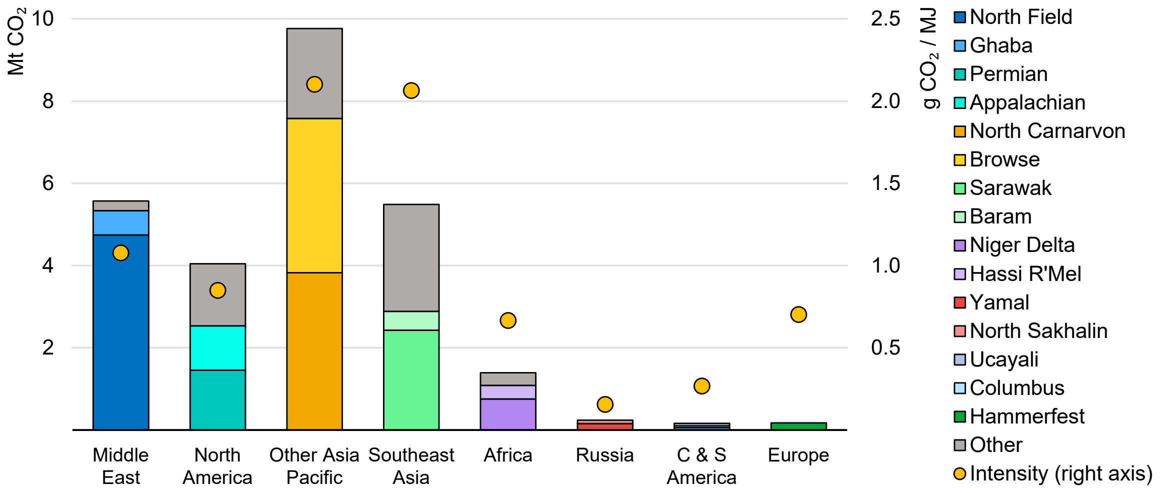
Naturally occurring CO_2 emissions

When it is extracted, natural gas often contains CO_2, hydrogen sulphide and heavier hydrocarbon molecules (e.g. butane and pentane). The CO_2 and hydrogen sulphide need to be removed (e.g. through amine treatment) and the naturally occurring CO_2 is then either reinjected or vented.

We estimate that around 25 Mt of naturally occurring CO_2 is extracted each year from feed gas, and around 20 Mt CO_2 is emitted to the atmosphere (Figure 7). This translates into a global average CO_2 emissions intensity of around 1.2 g CO_2/MJ. There is a very wide variation between regions ranging from around 6.3 g CO_2/MJ in the Browse Basin in Australia, mainly from the Ichthys LNG project, to less than 0.2 g CO_2/MJ in Russia. There is capacity to capture around

7 Mt CO_2 per year from LNG supply (0.75 Mt CO_2 from Snøhvit in the Hammerfest Basin of Norway, 2.2 Mt CO_2 from Ras Laffan LNG plant in North Field of Qatar, and 4 Mt CO_2 from Gorgon in the North Carnarvon basin of Australia).

Figure 7 Naturally occurring CO_2 vented from LNG feed gas and regional average CO_2 emissions intensities, 2024



Note: C & S America = Central and South America.

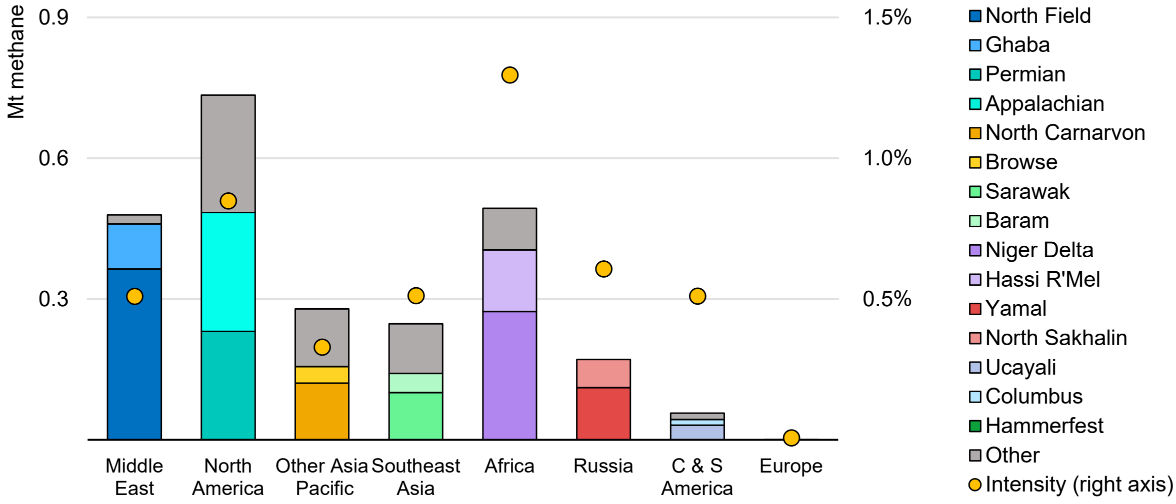
Methane emissions

Sources of methane before liquefaction include all methane emissions from production, gathering and processing. These can stem from intentional releases, often due to the design of the facility or equipment (e.g., compressors that vent to the atmosphere), operational requirements (e.g. venting a pipeline for inspection and maintenance) or for safety reasons (e.g. pressure relief valves). They can also result from unintentional leaks, due to a faulty seal or leaking valve, for example, or from the incomplete combustion of natural gas (e.g. at flares).

In total, we estimate that nearly 2.5 million tonnes (Mt) of methane were emitted during the production and processing of natural gas that was used as LNG feed gas in 2024 (Figure 8). The global average upstream methane emissions intensity of feed gas was around 0.6% (which translates into average emissions of 3.4 g CO_2-eq/MJ of feed gas). [3] There is a wide variation among sources: the best performers have an emissions intensity that is more than 100 times lower than the worst performers.

[3] The upstream methane emissions intensity is calculated here as methane emissions from natural gas operations divided by feed gas, assuming methane has an energy density of 55 MJ/kg.

Figure 8 Upstream methane emissions from LNG feed gas and regional average upstream methane emissions intensities, 2024



Note: Mt = million tonnes. Upstream methane emissions intensity = methane emissions from natural gas operations divided by LNG feed gas, assuming methane has an energy density of 55 MJ/kg. C & S America = Central and South America.
Sources: IEA analysis based on IEA (2025), Global Energy and Climate Model, IEA (2025), Global Methane Tracker (2025), and Rystad Energy (2025).

Transmission and distribution networks connect gas processing plants to LNG export facilities. We estimate that these emitted another 0.3 Mt of methane in 2024, which translates into a methane emissions intensity of 0.4 g CO_2-eq/MJ of gas transmitted. These emissions came mostly from compressors that vent gas by design (including reciprocating compressors and centrifugal compressors), pipeline or transmission station venting (e.g. to perform maintenance), unintentional leaks, and methane slip from generators driven by natural gas.

Flaring

Around 150 bcm of natural gas was flared globally in 2023, mostly associated gas from oilfields. In general, natural gas fields and fields that produce large volumes of marketable associated natural gas flare only during emergencies (since it is a waste of their marketed product). There are three main causes of flaring at LNG facilities: plant startups and shutdowns (e.g. during testing, process stabilisation and maintenance); unplanned events, such as equipment failure or process disturbances (e.g. compressor failure); and insufficient boil-off gas recovery.[4]

[4] During loading of LNG vessels, supercooled LNG often meets the “warm” tanks of LNG vessels, evaporating as methane emissions. While many facilities have recovery systems to collect and re-liquefy this “boil-off” gas, their capacity is sometimes insufficient, with some of the gas volume being flared.

Analysis from Capterio, based on data for all LNG plants globally, shows that flaring intensities can vary more than 100-fold between the best and worst performers, with some liquefaction plants flaring up to 3% of their LNG output.

We estimate that upstream assets feeding LNG facilities flared just over 1 bcm of gas in 2023. Most of this occurred in Algeria and Australia, followed by Russia and the United States. Another 2.5 bcm were flared directly at LNG facilities, with around 20% of this happening in Algeria, 15% in Qatar, 10% in Mozambique, and 10% in the United Arab Emirates. This total of 3.5 bcm of natural gas flared resulted in more than 6 Mt CO_2, which translates into around 0.3 g CO_2/MJ of feed gas. Flaring also causes methane emissions due to the incomplete combustion of natural gas at flares. We estimate that less than 0.1 Mt methane was emitted in upstream facilities in 2023 (this amount is already included in Figure 8) and a further 0.1 Mt was emitted in this way from LNG facilities. Methane emissions from the incomplete combustion of natural gas flared at LNG facilities therefore adds a further 0.2 g CO_2-eq/MJ of feed gas.

Liquefaction

Liquefying natural gas is the most energy-intensive process in the LNG supply chain and on average emits around 6 g CO_2-eq/MJ of LNG. For example, large-scale liquefaction plants (those that produce more than 6 bcm per year of LNG and which account for more than 90% of global production capacity in 2024), typically consume around 8-10% of the energy content of the feed gas to power their operations. Most of this energy is used for cooling the natural gas to -162 °C.

The different steps involved in the treatment and liquefaction of natural gas release CO_2 and can result in methane vents and leaks into the atmosphere. We estimate that CO_2 emissions account for more than 90% of total GHG emissions from liquefaction plants. A large fraction of CO_2 emissions comes from mechanical drive turbines that drive compressors used in the refrigeration cycles and power generation turbines for various other processes in the liquefaction plant. Smaller contributors include flaring and naturally occurring CO_2 (as discussed above), as well as natural gas combustion for gas pretreatment processes like dehydration, condensate stabilisation and in fractionation columns.

Methane emissions can occur during the treatment, liquefaction and storage stages. Methane can leak from incomplete combustion during flaring, compressor seal vents during routine operations or due to equipment degradation over time. It may also be vented during maintenance activities at the plant, along with releases from acid gas recovery units and nitrogen rejection units. Small amounts of methane can also leak from boil-off gas (i.e. LNG that regasifies as it warms over time), if it is not fully recovered and used.

Emissions vary depending on the technologies and operational practices used. For example, liquefaction processes like single mixed refrigerant, dual mixed refrigerant, propane mixed refrigerant, and the cascade process have different energy efficiencies, resulting in different emissions intensities. These emissions intensities vary further due to the turbine designs and models used in the liquefaction process, with older technologies often being less efficient than the latest ones.

Shipping

There are around 760 LNG-carrying ships in operation, with around 250 under construction for delivery by 2027 (including around 90 for 2025). Each year, these ships make around 7 000 round-trip voyages to deliver LNG from liquefaction to regasification terminals. The main types of LNG carriers handle around 95% of annual LNG trade (Table 1).[5]

Table 1 Summary of LNG carrier types and key characteristics

Carrier type	Stroke type	CO_2 emissions (g CO_2/MJ of LNG)	Average methane slip range (%)	Share of market (%)
Dual-fuel diesel electric (DFDE)	Four	2.8-3.2	4-6	25
Gas injection (ME-GI)	Two	2.0-2.4	0.2-1	10
Tri-fuel diesel electric (TFDE)	Four	2.8-3.2	4-6	20
Steam turbine	Not applicable	3.5-4.2	0	35
Dual-fuel (X-DF)	Two	2.4-2.8	0.6-3	10

On average, around 3.5 g CO_2-eq are emitted per MJ of LNG transported by an average sized carrier. This varies significantly depending on fuel use, engine type and performance, engine load and other operational conditions. The two main sources of emissions during shipping are fuel combustion and methane slip. Methane slip occurs when methane is unburnt and escapes via engine exhaust into the atmosphere.

Methane slip is more prevalent in low-pressure four-stroke engines such as DFDE and TFDE ships that use boil-off gas, especially when these ships operate at lower engine loads. Steam ships, which operate at higher pressure, generally do not use gas as a fuel and have negligible methane slip, but they have relatively high fuel consumption. In recent years, operators have moved towards more advanced designs – such as ME-GI and X-DF ships – with greater efficiencies and lower

[5] This study is focused on ships that transport LNG rather than ships that are fuelled by LNG.

methane slip. Innovations that have had positive effects on emissions reductions include the use of two-stroke instead of four-stroke engines, alongside the transition from spherical Moss tanks to membrane-type containment systems.

In total, around 800 petajoules (PJ) of fuel – primarily boil-off gas, but also heavy fuel oil and marine gasoil – were used to power ships transporting LNG in 2024. This led to emissions of around 55 Mt CO_2 and a further 10 Mt CO_2-eq of methane emissions (translating into an intensity of around 3.5 g CO_2-eq/MJ of LNG transported). This represents around 10% of total emissions from international shipping.

The highest emitting 10% of journeys resulted in more than ten times more emissions than the lowest emitting 10%. Differences in fuel use, ship speed and engine type play a role in this variation, but the primary factor explaining the wide range is the distance travelled. On average, a round-trip voyage for an LNG carrier is 10 000 km, but this can be as low as 500 km or as high as 27 000 km. On a regional basis, the emissions intensity of LNG-carrying ships varies significantly. For example, LNG shipped to the European Union produces average shipping emissions of around 2.5 g CO_2-eq/MJ, whereas for the People's Republic of China (hereafter, "China"), the average is around 3.3 g CO_2-eq/MJ. The route with the highest emissions intensity is between Yamal LNG in Russia and mainland China, which utilises Arctic ice breakers that are heavier and generally require more energy to operate than other ships.

These estimates fall within the range of recent studies such as Rosselot et al. (2024); Balcombe et al. (2022); and Thinkstep (2019), although they do come with a significant degree of uncertainty, especially around the issue of methane slip. There are limited primary measurement data, and so some organisations have put forward default values, for example the Fuel EU Maritime legislation. However, primary measurement campaigns on LNG-carrying ships have revealed total emissions are often higher than initially assumed.

Regasification

LNG cargoes are offloaded and regasified at onshore or offshore facilities, or at specially designed floating storage and regasification units (FSRUs). Depending on the geography, scale and type of application (e.g. for peak-load shaving or for baseload generation), operators choose from the available technologies, with varying degrees of efficiency, operational complexity, capital expenditure requirements and emission characteristics. The main technologies used to regasify LNG are open-rack vaporisers (used in nearly 90% of the world's regasification plants), submerged combustion vaporisers, shell and tube vaporisers, intermediate fluid vaporisers and ambient air vaporisers.

The main sources of emissions at open-rack vaporiser regasification plants stem from the power consumption of pumps circulating the heating fluids and LNG, boil-off gas compressors, other utilities, and the flare pilot. For submerged combustion vaporisers, the primary source of emissions is the combustion of natural gas to heat the LNG. Regasification energy demand typically consumes 0.3-0.5% of the LNG that is imported. Other emissions come from the electricity used in the regasification plant, methane emissions that can occur from plant hardware (e.g. leaks from compressors, valves, flanges and fittings, and those that occur during maintenance), and emissions related to LNG loading/unloading and bunkering activities, where applicable. Total GHG emissions from regasification are around 0.2-0.5 g CO_2-eq/MJ of gas regasified.

Box 3 Comparing the full life-cycle emissions intensities of LNG and coal

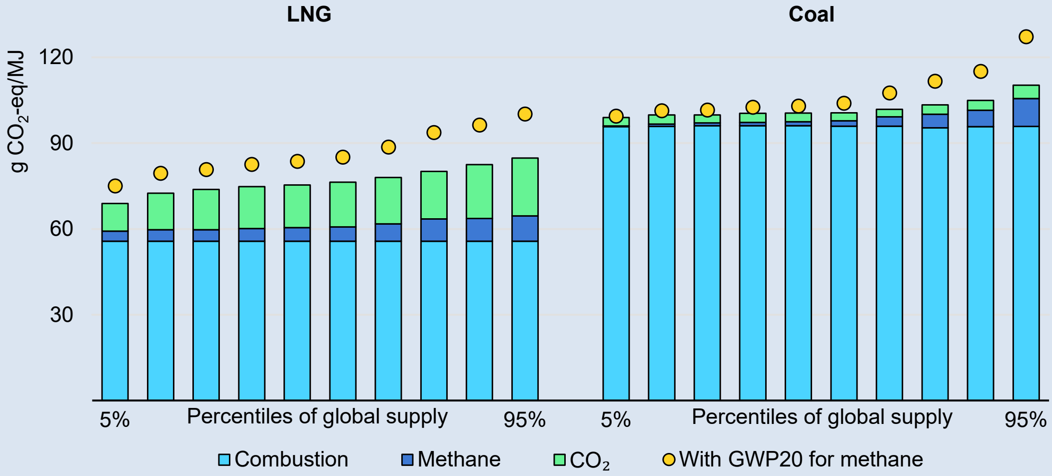
An oft-heard charge made against LNG is that methane emissions along the gas supply chain mean it has a higher life-cycle GHG emissions intensity than coal. IEA analysis does not support this conclusion. While there is a wide variation in the emissions intensities of coal and LNG, when all direct and indirect GHG emissions are factored in (from production to end-use combustion, for power and heat generation), we estimate that LNG results in about 25% fewer emissions than coal across energy use cases of these fuels (Figure 9).

Globally, on average, the life-cycle GHG emissions intensity of electricity produced from LNG is around 40% lower than electricity produced from coal. This is because gas-fired power plants are also generally more efficient in producing electricity than coal plants (the global average efficiency of gas-fired plants is 48%, while for coal-fired plants, it is 37%).

More than 99% of the LNG consumed in 2024 had fewer life-cycle emissions than coal. The choice of the conversion factor from methane to CO_2-eq has some impact on this share, but it does not change the overall picture. When using a 20-year GWP rather than a 100-year GWP, we estimate that more than 90% of the LNG consumed in 2024 still has lower life-cycle emissions than coal.

Nonetheless, comparing LNG only to coal sets the bar too low. Those making an environmental case for LNG use need to focus on minimising its GHG emissions intensity; it is not enough just to surpass the emissions performance of the most carbon-intensive fuel.

Figure 9 Estimates of life-cycle emissions intensities of LNG and coal, 2024



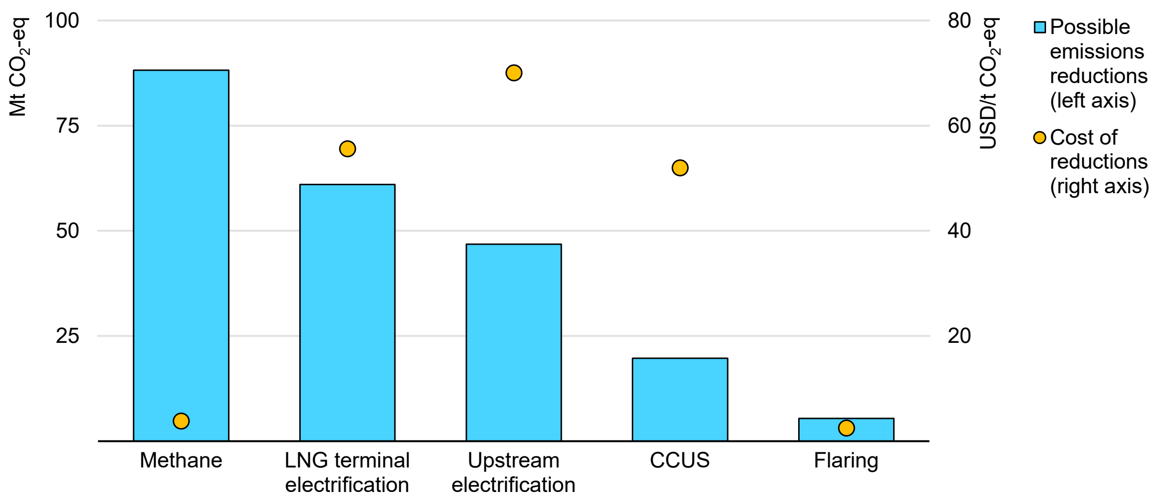
Note: GWP20 = 20-year GWP; g CO_2-eq/MJ = grammes of carbon dioxide equivalent per megajoule.

Emissions reduction opportunities and costs

Summary

Large emissions reductions across the LNG supply chain are technically achievable today. Many measures can achieve this at low or moderate cost. Tackling methane emissions is the most important and cost-effective contributor to overall emissions reductions from supply of LNG. Other options include electrification using low-emissions electricity, implementing efficiency improvements and CCUS, and elimination of routine flaring (Figure 10). This section focuses on the opportunities and costs of the direct emissions reduction opportunities in each area.

Figure 10 Annual emissions reduction potential across the LNG supply chain by selected measure and global production weighted average CO_2 cost, 2024



Notes: Cost of reductions can vary widely between basins, LNG facilities, and countries; CO_2 costs shown are global averages weighted by production. Assumes electrification either through a grid connection with low-emissions electricity or a dedicated renewable electricity installation. CCUS estimates are based on capturing pure streams of naturally occurring CO_2 and injecting into a nearby basin. One tonne of methane is taken to be equivalent to 30 t CO_2 based on a 100-year GWP (IPCC [2021], Sixth Assessment Report).

Reducing methane leaks can cut annual emissions by close to 90 Mt CO_2-eq. Upfront investment is needed to deploy methane abatement measures, but many of these will provide enough gas savings over their lifetimes to cover the required outlays, and around half of methane emissions from the LNG supply could be cut at no net cost. Reducing flaring at LNG facilities and fields providing feed gas can lower annual emissions by a further 5 Mt CO_2.

While the upfront costs can be high, the electrification of upstream facilities and LNG terminals, and the use of low-emissions-intensity electricity to power these, would significantly reduce the emissions associated with liquefying and compressing natural gas. Several electrified LNG facilities have already been established, although electrifying some existing LNG facilities may be challenging, particularly those that are nearing the end of their technical lifetime. In total, we estimate that electrification of existing LNG liquefaction terminals could cut annual GHG emissions by around 60 Mt CO_2-eq. Moreover, more than 40% of upstream natural gas production sites that feed LNG terminals are near an electricity grid, and electrifying these is also an option to reduce emissions. Doing so in such areas could cut another 50 Mt CO_2-eq. Further emissions reductions are also possible from a broad set of process efficiency improvements across the LNG supply chain.

The use of CCUS is also under way in the LNG supply chain. The sharing of lessons learnt and experiences from the establishment of routine and at-capacity gas capture and injection will be key to further benefiting from this technology.

We estimate the upfront capital investment required to implement electrification, methane reduction and CCUS at all viable facilities along the existing LNG supply chain is just over USD 100 billion. Electrifying upstream operations that feed gas to LNG terminals would cost USD 50 billion, and electrifying operations at LNG terminals would cost USD 35 billion. CCUS to capture naturally occurring CO_2 at fields with high concentrations would require USD 7 billion, and methane abatement and flaring reductions just over USD 5 billion. Implementing all these measures would avoid a total of 220 Mt CO_2-eq of GHG emissions per year once implemented – around 60% of total emissions from the LNG supply chain – at a weighted average CO_2 cost of USD 40/t CO_2. Globally, on average, this would add around USD 1 per million British thermal units (MBtu) to the delivered cost of LNG from existing LNG facilities. Integrating such measures into new, greenfield LNG projects as part of the front end engineering and design (FEED) phase would likely have a lower cost than retrofitting existing terminals.

Reducing methane emissions

In total, we estimate 3.5 Mt of methane emissions were emitted from across the LNG supply chain in 2024 (around 10% of total methane emissions from natural gas operations globally). Upstream operations accounted for around 70% of these, with natural gas transmission, LNG liquefaction, shipping, and other downstream operations responsible for the remaining 30% (Figure 11).

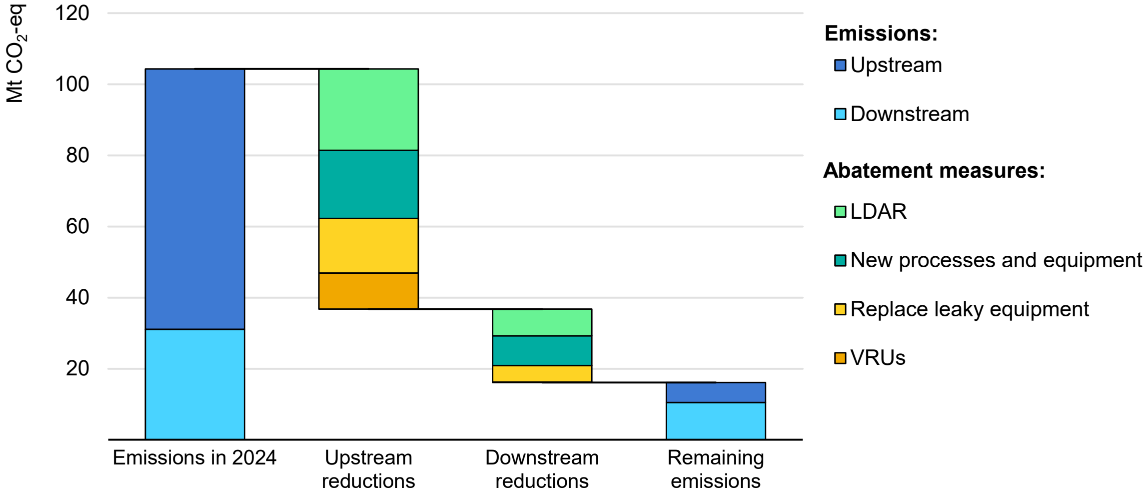
Figure 11 Shares of methane emissions from LNG and related natural gas operations, 2024

Many technologies are now available to reduce these emissions (Figure 12). Examples include: leak detection and repair (LDAR); replacing gas-driven controllers and other methane-emitting equipment with electric devices; using vapour recovery units to capture low-pressure gas that would be vented; and blowdown capture (when equipment is depressurised and gas is recovered instead of being vented). Some measures require minimal investment and can be deployed quickly by operations staff (e.g. improving combustion efficiencies by better monitoring these processes, maximising plant reliability through predictive maintenance and optimising operations to minimise losses).

We estimate that if all the abatement technologies available today were to be deployed along the LNG supply chain, this would cut methane emissions by around 85% from 2024 levels. The average upstream methane emissions intensity would fall from around 0.7% to 0.1%, and the average downstream methane emissions intensity would fall from around 0.3% to 0.1%.[6] Several member companies of the Oil and Gas Methane Partnership 2.0 already report methane emissions intensities of much less than 0.1%.

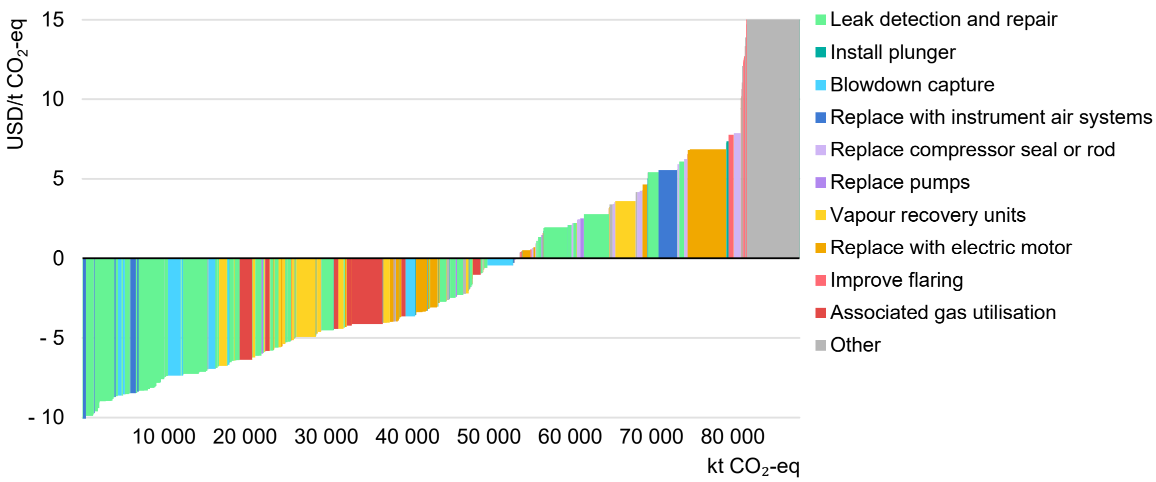
[6] Downstream methane emissions intensity is calculated here as methane emissions from transmission, liquefaction, shipping and regasification divided by natural gas delivered to the regasification terminal, assuming methane has an energy density of 55 MJ/kg.

Figure 12 Methane emissions from the LNG supply chain and abatement options, 2024



Note: LDAR = Leak Detection and Repair. VRU = Vapour Recovery Units. "New processes and equipment" = blowdown capture, routing vents to recovery systems, measures to improve combustion efficiencies, and retrofitting ships to use engines with lower methane emissions. "Replace leaky equipment" = instrument air systems, electric pumps, and other measures that involve replacing existing equipment. One tonne of methane is considered to be equivalent to 30 t CO_2 based on the 100-year GWP (IPCC [2021], Sixth Assessment Report).

Figure 13 Marginal abatement cost curve for reducing methane emissions from the LNG supply chain, 2024



Notes: LDAR = Leak detection and repair. Other includes green completions, pipeline pump-down before maintenance, installing methane-reducing catalysts and retrofitting LNG carriers with engines that minimise methane slips. One tonne of methane is considered to be equivalent to 30 t CO_2 based on the 100-year GWP (IPCC [2021], Sixth Assessment Report).

In LNG facilities, boil-off gas can often be recovered, automated air/fuel ratio controls can improve the combustion efficiency of natural gas-powered engines and turbines, and nitrogen can replace natural gas if a flare system is continuously purged. LDAR can reduce unintentional emissions, and measures such as using compressors with dry seals can reduce emissions from normal operations. There are several measures to address emissions from utilities, storage, pumps and other equipment present at LNG facilities. Minimising the number of startups and other operational improvements can also help cut emissions.

Methane emissions from shipping can be also be minimised. This can be done by avoiding low loads and by implementing cylinder deactivation at low load. Another option is to improve operational controls – including process control, variable valve timing, gas metering and optimal air/fuel ratios – or to use best available technologies, such as engines that minimise methane slips. Tests are also under way to deploy methane oxidation catalyst systems that tackle methane slips.

Several companies are working to improve methane monitoring and reduce emissions. In 2024, for example, Cheniere Energy completed measurement studies at its liquefaction plants and set a target for those plants of annual methane emissions intensity of 0.03% per unit of gas delivered. Enagás has reduced its emissions intensity by eliminating pneumatics powered by gas, by using boil-off gas compressors in LNG regasification plants, and by deploying electric pumps.

To encourage methane abatement, companies can integrate methane-specific performance indicators into their financial and operational strategies (e.g. by tying them to employee and executive compensation). They could also establish an internal price for methane when making capital investment decisions.

Accurate measured data are not a prerequisite for tackling methane emissions, but they are helpful. They allow jurisdictions and companies to effectively target methane emissions by identifying major sources, abatement opportunities, costs and potential savings, while tracking progress over time and helping with regulatory oversight. Technologies for monitoring methane emissions, notably from satellites, are advancing rapidly and promise to improve quantification capabilities, raise public awareness and support regulatory oversight in the coming years.

Most company and country methane inventories are based on multiplying activity data (e.g. number of facilities or extent of operations) by standardised emission factors (e.g. default values or leak rates for particular types of equipment). Measurements from satellites and airborne observations suggest actual emissions levels are often much higher.

The quality of reporting varies widely, with many oil and gas companies failing to report emissions at all. If the oil and gas companies that report their emissions were fully representative of the entire industry, it would imply that methane emissions are more than 90% below our estimates. Tools are available to guide operators through the different measurement technologies. An optimal system combines different measurement technologies in a way that is geographically and temporally representative.

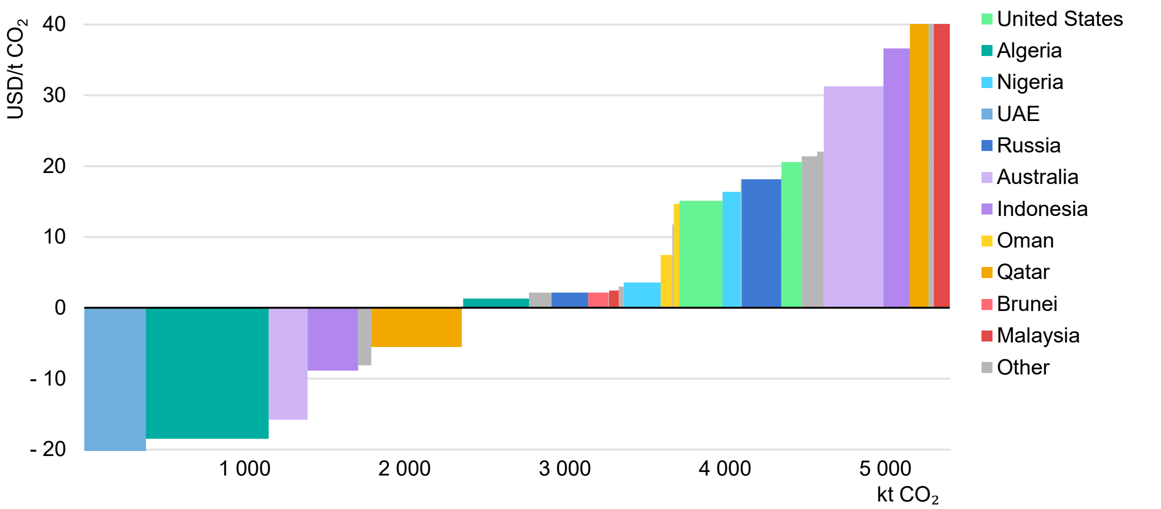
More than 80% of LNG flows comes from companies that are members of the Oil & Gas Methane Partnership 2.0, which is the United Nations Environment Programme's measurement-based reporting framework for the oil and gas industry. So far, few meet the highest level of reporting, where site-level measurements are reconciled with source-level emissions inventories, but several are expected to reach this level in 2-3 years.

Better data provide an opportunity for certification schemes to catalyse further methane abatement and an avenue for greater collaboration between buyers and suppliers. In July 2023, Japan and Korea (alongside partners) launched the CLEAN initiative. This is a public-private project to foster dialogue among LNG producers and consumers and improve the understanding of emissions and ongoing methane reduction efforts.

Reducing flaring

There are many options to use natural gas that is flared, including by bringing it to consumers via a new or existing gas network, reinjecting it to support reservoir pressure and converting it to LNG (Figure 14). The gas can also be used to generate power, which can be equipped with CCUS to reduce emissions.

Figure 14 Marginal abatement cost curve of reducing flaring along the LNG supply chain, 2023



Notes: Does not include avoided methane emissions. Abatement options include installing new gas pipelines or pipeline connections, mini-compressed natural gas and mini-LNG technologies, gas-to-power projects and re-injection as outlined in previous IEA analysis.

There should be minimal methane emissions if a flare is designed, maintained and operated correctly. However, that is not always the case, and higher emissions can occur due to factors such as weather and changes in production rates.

Occasionally, an active flare may be totally extinguished, resulting in the direct venting of methane gas to the atmosphere that should have been combusted. We estimate flares have a global average combustion efficiency of around 90%, which is significantly lower than the standard assumption of 98%.

Technologies and maintenance practices can improve the efficiency of existing flares. For example, using flare tips with modern designs that improve fuel and air mixing, or converting to flare stacks that ensure adequate fuel-air mixing to consistently achieve high combustion efficiencies, can significantly reduce emissions resulting from poor combustion efficiency.

Various initiatives are under way to reduce flaring around the world. For example, some energy companies, governments and institutions have endorsed the Zero Routine Flaring by 2030 initiative launched by the World Bank and the United Nations in 2015. For new fields, operators should aim to develop plans to use or conserve all the field's associated gas without routine flaring. At existing oilfields, operators are asked to eliminate routine flaring when it is economically viable as soon as possible, and no later than 2030.

Flaring reduction projects face many barriers, including lack of infrastructure, contractual terms that prevent natural gas savings from affecting revenue, or information gaps on flared volumes and characteristics (e.g. how much is routine flaring). In the LNG supply chain, most flaring reduction options would come at a net positive cost in the absence of regulatory requirements. Small volumes often make it costly to recover investment through developing new infrastructure or by gas transport. It is also often more challenging to reduce flaring in offshore facilities due to space and weight constraints, as well as higher investment needs.

Nevertheless, there are measures available to reduce flaring that require little investment and which are often cost-effective. These include better planning of commissioning and maintenance activities to avoid flaring during facility startups. Also, optimising operations and building redundancy to minimise upsets and equipment failure linked to gas flaring.

Increasing process efficiency

Upstream

A large portion of the energy required at upstream facilities is to power electrical equipment, with the electricity often produced using small-scale onsite natural gas generators. These are inefficient and also use some of the products that could be sold instead. Using more efficient equipment – such as swapping an open-cycle gas turbine for a combined cycle – can save around 30% of the energy required. Other options to improve efficiency include optimising the performance of compressors and wells and improving pipeline flow during gas transport.

Most of the energy used at compressor stations in gas transmission comes from the natural gas itself. Optimisation tools can reduce fuel use by improving operational efficiency: based on information provided by service providers, we estimate abatement costs to be around USD 60/t CO_2, with payback times of less than 2 years.

Optimising the operational performance of wells can reduce the energy used during natural gas extraction, while increasing throughput by up to 30%. This can be done, for example, by using autonomous well control systems to dynamically respond to reservoir pressure. These are commercially available today, but their use requires a high level of digitalisation (i.e. real-time sensors, data connectivity and availability). Opportunities are typically at larger fields, and we estimate that the practical applicability of these tools is limited to about 30% of LNG-linked upstream assets in operation today. For these assets, based on the information received from industry and service providers, around USD 100-500 thousand upfront investment is required per well and USD 50-200 thousand for subsequent deployments with a payback period of a few months. Similar deployments in fields that are not digitally mature could increase upfront investment requirements to USD 1-5 million, depending on the complexity of the operations, while potentially bringing much larger efficiency gains.

Transporting oil and gas from the point of extraction to processing facilities can consume up to 7% of the total extracted energy, depending on factors such as fluid type, flow regime, pipeline diameter and transport distance. Applying drag-reducing additives, often in combination with internal coatings, can improve pipeline flow and cut energy losses due to friction by over 60% and increase throughput by 5% to 10%. Maintaining good flow assurance practices (e.g. preventing hydrate plugs that can cause increased flaring or emergency venting to the atmosphere, or keeping pipelines clean through regular pigging) can also help improve performance. These solutions are likely applicable across a broad range of pipeline operations and would be particularly effective in long-distance transport and regions with high hydrate formation risks.

Liquefaction

Liquefaction is the most energy-intensive process in the LNG supply chain, most of which is used in turbines that drive compressors to liquefy the natural gas and in power generation turbines that power processes in the liquefaction plant. There are several options available to reduce fuel use including the use of more efficient turbines, improving heat integration, and using mixed refrigerant cycles or multicycle refrigeration processes. (The possibility to fully electrify liquefaction facilities, which would also provide a major boost in efficiencies, is discussed below).

Heavy-duty simple-cycle industrial gas turbines typically operate at efficiencies between 30% and 38%. With the addition of combined cycles, the efficiency can be increased to more than 60%. The additional cost of installing a combined-cycle plant can be recovered through annual fuel savings, particularly in countries with high fuel costs or feed gas constraints. The latest aeroderivative turbines offer efficiencies up to 44% for simple-cycle turbines and up to 56% in combined-cycle electrical power co-generation. Compared with industrial gas turbines, they have faster startups, improved turndown capabilities (due to their variable speed drive capabilities) and have generally a smaller footprint. However, they typically come with a lower power output per unit, high ambient temperature sensitivity, and more frequent service requirements.

For new LNG facilities, installing aeroderivative turbines rather than heavy-duty industrial gas turbines would require changes to facility and system design and this might entail additional costs beyond the equipment itself. We estimate that this capital expenditure differential of USD 40-70 million would often be recovered in less than 3 years as a result of reduced fuel use and that it would therefore have a slightly negative cost per tonne of CO_2 avoided.

At existing LNG facilities, replacing old gas turbines with new aeroderivative turbines is generally logistically difficult and capital intensive as it would require civil works for equipment access, installation of new infrastructure and addressing system integration challenges. There would also be a loss of revenue due to operational downtime, with potential disruption to existing supply contracts. We estimate the cost of those retrofits to be typically in the range of USD 60/t CO_2 to USD 90/t CO_2 depending on the train size and complexity of the plant. However, significantly higher costs would be incurred for shutdowns exceeding a downtime period of six to eight weeks.

Improving heat integration can also reduce energy use in liquefaction plants. Exhausts of gas turbines typically provide waste heat streams at 400-600 °C and these could be used in equipment like regen heaters and amine regenerator reboilers to reduce overall fuel use. Experimental studies show up to 17% fuel use reductions are possible through investments, with a payback period of just over 2 years, compared with conventional systems with compressor-based precooling stages.

The use of mixed refrigerant cycles (e.g. dual mixed refrigerant or propane precooled mixed refrigerant) can reduce energy use by around 5-15% compared with single refrigerant cycles. However, they come with a higher upfront investment requirement and technical complexity and may not be feasible for small-scale liquefaction plants. Mixed cycles enable lower emissions and better energy performance, particularly in baseload liquefaction plants with variable cooling requirements. Precooling and mixed refrigerant cycles are most effective in plants with waste heat recovery potential or flexible refrigerant needs.

Shipping

A wide range of technical and operational levers to improve the energy efficiency of LNG-carrying ships are commercially available or are in advanced stages of deployment as highlighted in the IEA's earlier publications. These range from optimised ship designs to various operational measures in cruising and hull maintenance (Table 2). The lever with the highest impact so far has been slow steaming (reducing the cruising speed of the vessel), which has been responsible for around two-thirds of the efficiency improvements in LNG-carrying ships since 2008.

Table 2 Selected examples of fuel-efficiency levers for LNG-carrying ships

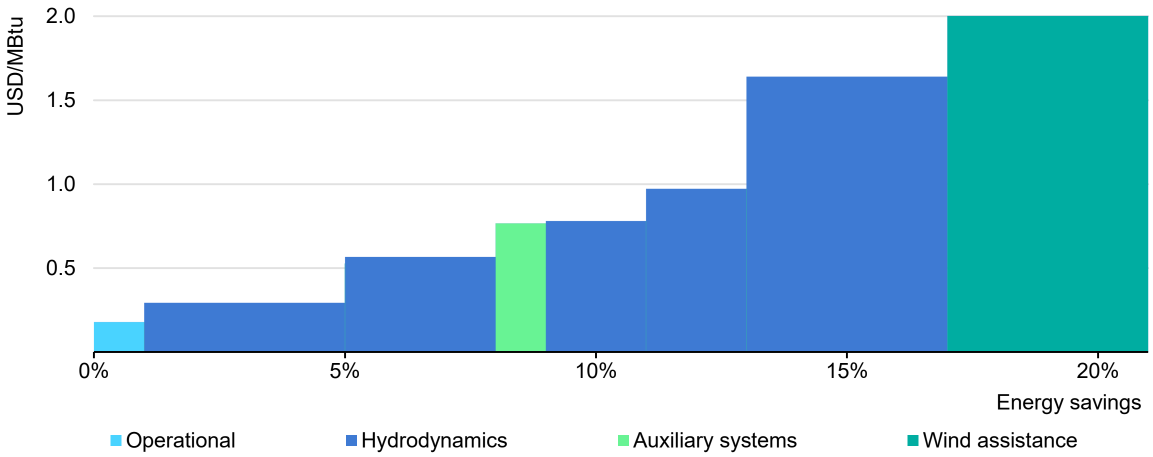
Lever	Fuel saving	Capital expenditure	Payback period	Remarks
Slow steaming	A 10% speed reduction would save up to 20% (accounting for longer sailing times)	Near zero	Immediate	Largest lever at no cost, no need for technology deployment, but loss of carrying capacity (which could be alleviated by just-in-time arrivals and reducing waiting times at ports)
Operational improvements	Up to 5% per technology	USD 100-500 thousand per fleet for dynamic route optimisation	1-2 weeks to months	Levers also include trim and draft optimisation, autopilot upgrade
Hydrodynamics improvements	3-10% per technology	USD 50-600 thousand for antifouling nano-coatings, USD 1-3 million for air lubrication	Less than 3 years for coatings, 3-7 years for air lubrication	Available technologies also include improved hull and pre/post swirl devices design
Auxiliary systems	Up to 2%	USD 50-100 thousand for systems with low to moderate complexity	Less than 2 years	Involves the optimisation of cooling water systems, heat exchangers, heating and ventilation systems
Wind assistance	Up to 10%	USD 0.5-3 million per ship	2-20 years depending on type	Increasing orders, use in LNG shipping limited

Source: IEA (2024), Energy Technology Perspectives 2024 (Annex C).

Several of these technologies would make economic sense for ship-owners and they can be bundled in a way that allows for energy savings of more than 20% (Figure 15). This would lower costs by about USD 3 million per year, reduce the total cost of ship ownership by up to 10%, and have a payback period of less than 5 years at an LNG price of a USD 10/MBtu.

The International Maritime Organization (IMO) has incentivised energy efficiency improvements in shipping through its energy efficiency existing ship index, which requires ships to meet minimum emissions intensity standards by adopting higher-efficiency technologies, as well as its carbon intensity indicator rating, which evaluates operational emissions per cargo mile, and incentivises measures such as hull cleaning and speed optimisation to improve energy efficiency. The IMO also recently approved a legally binding framework to reduce shipping emissions to net zero by around 2050, which is expected to be adopted in October 2025. This includes regulations on a goal-based marine fuel standard and a global carbon pricing mechanism.

Figure 15 Marginal cost of efficiency improvements for a typical LNG-carrying ship



Note: MBtu: million British thermal units. Assumes an LNG ship of 160 000 cubic metres of capacity built in 2025. Energy savings are calculated over the 20-year lifetime of the ship. Operational = trim and draft optimisation, autopilot upgrade; Hydrodynamics = hull shape optimisation, pre/post swirl devices, nano-coating, air lubrication; Auxiliary systems = optimisation of cooling water systems, heat exchangers, heating and ventilation systems.

Regasification

The choice of regasification technology used in terminals is highly dependent on the geography and capacity requirements. Most of the terminals use open-loop systems that are more efficient in warmer climates, but they may face environmental restrictions for thermal discharge. Closed-loop systems, although more energy intensive, offer more consistent performance across geographies and can be integrated with energy recovery systems for higher efficiency.

The main regassification energy efficiency improvement opportunities lie in two areas. The first is enhancing waste heat integration from nearby low-grade heat sources (e.g. exhaust gases from FSRUs, steam from nearby power plants or residual heat from industrial processes). Gas-heated vaporisers have high fuel use of up to 1.5% of the regasified LNG stream. Reutilising low-grade waste heat would avoid those emissions (potentially reducing fuel use by up to 50%).

The second is utilising the cryogenic energy of LNG, with installed system costs in the range of USD 2-5 million depending on the size and geography of the facility. Cold energy utilisation is an untapped resource, even for locations with feed gas limitations or high electricity costs, due to high upfront investment needs, limited opportunities for energy integration and lack of incentives for energy recuperation. Less than 1% of regasification terminals use the cold energy potential available globally.

Emerging solutions include integrating organic Rankine cycles at FSRUs to use the cold energy. This may reduce fuel use by up to 20% in comparison with existing closed-loop regasification systems, while capturing 90% of the CO_2 in the boiler flue gases and fully meeting the power needs of the FSRU without the need for dual-fuel engines.

Electrification

Electrification offers a major opportunity to reduce the emissions associated with energy used in upstream and liquefaction facilities. In most cases, this would provide a boost to energy efficiency. If low-emissions electricity is used, it would significantly reduce these emissions.

Liquefaction

The main options to electrify LNG liquefaction terminals are to replace onsite gas turbines for power generation with renewables and batteries, or a grid connection where low-emissions electricity is available, and to replace mechanical gas turbines used for compression with electric motors**.** Emissions reductions arising from electrifying operations can vary depending on the solution chosen.

LNG facilities require electricity for a range of different processes, primarily compression (if not using mechanical gas turbines), as well as vapour and boil-off, control systems, heating, ventilation and air conditioning, and loading and berthing systems. Replacing onsite gas turbine power generation with renewables and battery storage systems or with low-emissions electricity from the grid could significantly reduce these emissions while also delivering significant efficiency improvements.

LNG liquefaction requires a significant amount of compression, especially for the main refrigeration process. Replacing mechanical gas turbines with electric motors can improve the efficiency of this process. If powered by high-efficiency sources like grid electricity or onsite combined cycle gas turbines, this shift can reduce liquefaction energy use from 8-10% of feed gas energy to as low as 6%. This would allow for greater flexibility, faster start-up capabilities and higher availability.

A hybrid approach that combines these two aspects could also be adopted, for example by using electric motors for compression and either renewables with battery storage or grid electricity for power requirements to fully replace gas turbines.

Hammerfest in Norway and Freeport LNG in the United States have, so far, been the major all-electric LNG plants. Hammerfest LNG has electrified its compressors but continues to use natural gas to power them. It is planning to develop a grid connection to draw power from Norway's hydro-dominated electricity mix. Freeport LNG, which was commissioned in 2019, secured a grid connection to supply 675 megawatts (MW) of power capacity to drive its compressors. This enabled a 90% reduction in site combustion CO_2 emissions and a net LNG production increase of 6.5% relative to a design based on traditional natural gas turbines.

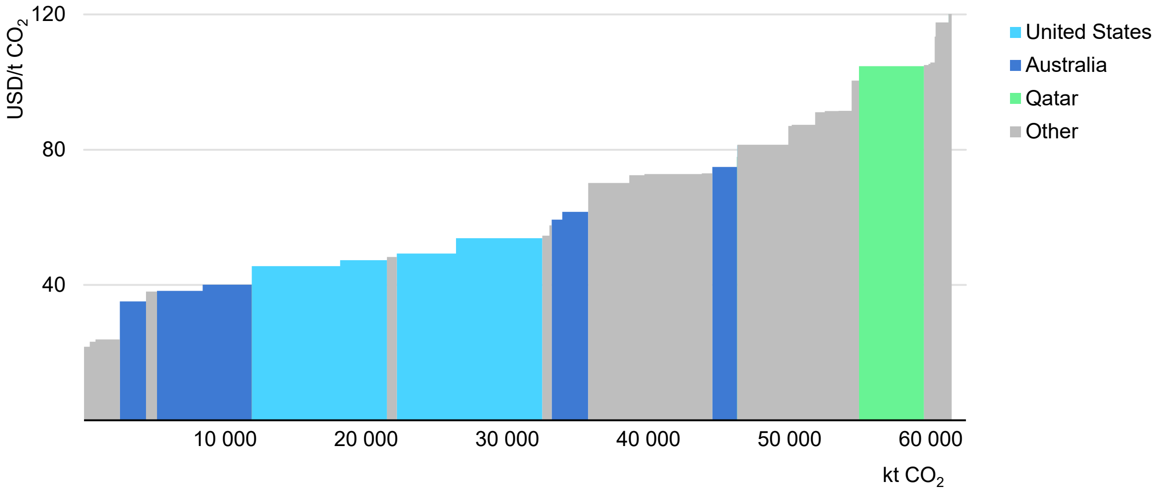
Interest in all-electric LNG terminals has been growing. In 2024, three sanctioned LNG export projects plan to be fully electrified: Ruwais LNG in the United Arab Emirates, which plans to run on renewable and nuclear grid power, Cedar LNG in Canada, which plans to use grid electricity, and Marsa LNG in Oman, which is constructing a dedicated 300 MW solar photovoltaic (PV) plant.

Electrifying existing LNG terminals can involve significant costs and requires site-specific assessments of the technical feasibility and associated costs and may involve trade-offs. Initial capital expenditure can be high, and operators may be hesitant given the potential revenue loss and operational downtime associated with the conversion process. Electric transmission upgrades are also often required to connect to LNG export facilities as these typically require a high electrical load.

LNG operators face several choices when implementing an electrification programme, including selecting the technology and design for compression, and the appropriate strategy for procuring power supply. For projects pursuing a grid connection, costs vary depending on factors such as distance to the power grid, level of reinforcement required and contractual conditions, including, crucially, the power purchase price. For projects building dedicated power generation capacity, it is important to ensure a continuous, reliable source of energy to maintain operations and ensure safety. There are several solutions available to do so, including pairing batteries with variable renewable sources such as solar PVs or wind, or retaining existing gas-based assets for back-up power or in a hybrid system configuration. Whatever the configuration chosen, the value of avoided natural gas use can be factored into the economic assessment.

Through a detailed geospatial assessment of proximity to nearby electricity infrastructure and solar and wind potential, we have assessed the costs to electrify existing LNG liquefaction terminals around the world using low-emissions electricity (Figure 16). We exclude terminals older than 15 years, given the challenges and additional costs associated with undertaking large-scale retrofits for such plants, leaving around 300 bcm/year of capacity that can potentially be electrified. We estimate the upfront capital cost of fully electrifying these plants would be around USD 35 billion. Doing so would avoid around 60 Mt CO_2 per year associated with the energy required for LNG liquefaction. Taking into account the discounted cash flows associated with the upfront investments, allowing for downtime, additional operating costs, but also additional feed gas availability, this investment would require a weighted average CO_2 cost of around USD 55/t CO_2. On average, this would add around USD 0.4/MBtu to the delivered cost of LNG.

Figure 16 Cost of electrifying existing LNG export terminals using low-emissions electricity, 2024



Upstream

Around 40% of natural gas production sites that feed LNG terminals lie within 10 km of an electricity grid, and 75% are in areas with good wind or solar resources. The energy at upstream facilities could therefore be provided by electricity from a centralised grid or generated in a decentralised renewable energy system. Norway has led efforts to electrify upstream oil and gas operations, with grid connections or dedicated offshore wind installations being integral parts of its plan to reduce emissions by 70% from Norway's Continental Shelf production by 2040. BP has electrified a substantial portion of its assets in the Permian Basin in Texas. However, there are few examples of large-scale actions being taken by other oil and gas producers, especially for existing assets.

Policy or regulatory incentives may be necessary to stimulate the required upfront investment. These could take the form of a CO_2 price – which provided the spur for development in Norway – or might come in the form of tax breaks or exemptions on a portion of electricity tariffs. Costs could be kept down if operators collaborate to build shared clean electricity infrastructure that would feed wider areas of production (e.g. recent efforts by companies operating in the North Sea). Project economics could also be improved by crediting avoided CO_2 or selling surplus renewable electricity back to the grid.

We estimate that upfront investment costs of around USD 50 billion would be required to electrify existing upstream assets that provide feed gas, using a dedicated grid connection or decentralised renewable system (this assessment excludes assets that are impractical for full electrification, such as those that require substantial amounts of heat and those that are in remote locations far from grids or with low solar or wind resources). Doing so would avoid around 50 Mt CO_2 per year at a weighted average CO_2 cost of around USD 70/t CO_2 (adding around USD 0.4/MBtu to the delivered cost of LNG).

Carbon capture, utilisation and storage

There are two main opportunities to equip CCUS along the LNG supply chain: to capture naturally occurring CO_2 which is often present in feed gas and to capture CO_2 emissions produced from gas combustion at LNG liquefaction terminals.

Three LNG projects are currently equipped with CCUS to capture the naturally occurring CO_2. The Ras Laffan LNG plant, which has been operating since 2019 can capture up to 2.2 Mt CO_2 per year; the Snøhvit project in Norway separates up to 0.75 Mt CO_2 per year from the gas stream from the Hammerfest LNG plant and injects this into a saline aquifer; and the Gorgon LNG project was designed to capture and store 4 Mt CO_2 per year over a 40-year life-cycle. Gorgon LNG has not yet reached full capacity and has been operating at around half of its full operational CCUS capacity on average since startup.

Upcoming projects are also planned: the Tangguh LNG project received final investment decision in 2024 to build CCUS infrastructure targeting the capture of around 2.5 Mt CO_2 annually, and Malaysia LNG is planning a major CCUS facility. There are also plans to capture and store an additional 4 Mt CO_2 annually from Qatar's North Field LNG Expansion Project.

Streams of naturally occurring CO_2 at the liquefaction plants are usually pure and the cost of CO_2 capture is often around USD 20/t CO_2 to USD 50/t CO_2, depending on the scale of operations (further details are available in the IEA CCUS Projects Database). For LNG sources with high levels of naturally occurring CO_2, capturing these emissions would add around USD 0.1-0.2/MBtu to the delivered cost of LNG. In some cases, the capture cost could be offset by revenues from selling CO_2 to oil producers for enhanced oil recovery.

CO_2 streams from gas combustion are much less pure than for naturally occurring CO_2, and no LNG projects currently use post combustion CCUS to mitigate these emissions. Capture costs vary by project size and maturity but are estimated to average around USD 110/t CO_2 to USD 140/t CO_2 avoided, which would add approximately USD 0.7-0.9/MBtu to the cost of liquefaction.

Retrofitting CCUS into existing LNG plants is technically complex and costly, requiring major modifications to integrate the large CO_2 capture systems. Additional infrastructure such as pipelines, compression, and storage facilities can push capital expenditures into the hundreds of millions. Downtime during retrofits can also lead to revenue loss and potential contractual penalties.

After capture, the CO_2 needs to be transported and stored, and costs for these depend on the availability of storage near to the capture location. For operations or liquefaction plants with nearby storage options, we estimate the additional cost for transport and storage is around USD 15/t CO_2 to USD 30/t CO_2. At deep offshore locations that require transport between the mainland and the storage location, transport and storage costs are expected to be around USD 75/t CO_2 to USD 150/t CO_2.

Qatar is already aiming to expand the use of CCUS at some of its new LNG facilities, and elsewhere, Australia and the United States also have good opportunities to equip CCUS to LNG facilities.

In the United States, many existing and planned LNG projects are concentrated around the Gulf Coast area, where operators have access to the existing market and CO_2 pipeline network for enhanced oil recovery. Lower costs for CO_2 transport, potential revenues from the sale of oil and tax credits available for captured CO_2 would considerably improve the business case for CCUS projects. In Louisiana and Texas, eight LNG projects have announced plans to implement CCUS.

In Australia, there are strong geographic and regulatory advantages for integrating CCUS with LNG production. There are some non-LNG-related CCUS projects in operation, and others are advancing that will add several million tonnes of annual capture and storage capacity, building critical operational experience and technical capabilities. Ongoing policy, regulatory and financial support, and the proximity of LNG facilities to large, well-characterised storage sites, particularly in Western Australia and the Northern Territory, improve project economics and development opportunities but challenges still abound. Going forward, Australian regulations will require all new gas fields to be net zero with respect to reservoir CO_2 from the start of operations.

Annexes

Technical annex

This report provides a consistent set of estimates for CO_2 and methane emissions from LNG supply chains based on the latest best available data. These reflect a detailed spatial representation linking upstream assets to LNG terminals, the latest scientific studies and measurement campaigns, and emissions data from a variety of sources including the IEA Global Methane Tracker (2025), the IEA's Global Energy and Climate Model (2025), the World Bank (for flaring), the Oil Climate Index plus Gas tool (OCI+) (for energy use in production and processing), the International Maritime Organisation, the EPA, and company- and country-reports.

LNG supply chains are complex and can evolve quickly, and literature reviews have identified large differences in emissions over time even for the same assets. Data on GHG emissions are often not available, and, even when they are, they seldom reflect direct emissions measurements. These uncertainties are compounded by challenges in apportioning emissions to LNG supply (versus oil and other co-products) and tracing the feed gas from production sites to liquefaction terminals. Estimates are also often based on generic information, e.g. reservoir CO_2 content for naturally-occurring CO_2.

In this work, the mapping of upstream assets to LNG liquefaction assets used data from the EIA, FERC and company reporting for the United States, and from Rystad Energy for the rest of world. We first linked all individual upstream gas assets that are known to produce LNG feed gas to each LNG terminal. Physical links and supply contracts often provide enough information to estimate the percentage of feed gas flowing to a specific terminal that comes from each upstream asset. Where no other information was available, we estimated the contribution of each upstream asset based on its total production, overall pipeline capacities, and other operational details (e.g. reports of outages). We estimated emissions intensities for the upstream assets (as detailed below) and took the production weighted average to give the average emissions intensity of feed gas at each LNG terminal on an annual basis. Overall, we considered production and emissions from around 40 upstream basins that produce feed gas for LNG export.

Our estimates of CO_2 emissions from the energy used in production and processing are based on country- and production-specific (e.g. conventional onshore, conventional offshore and shale gas) data from the OCI+ tool. These are based on a detailed field-by-field dataset created by the Rocky Mountain Institute using the Oil Production Greenhouse Gas Emissions Estimator (version 3.0a), which considers the energy required for each individual production stage (e.g. exploration, development, drilling, extraction, processing and maintenance). Estimates of energy use and CO_2 emissions from feed gas transmission were based on life cycle and global supply chain assessments and regional reports from the European Energy Research Alliance and FENEX.

Estimates of vented naturally-occurring CO_2 emissions are based on a basin-by-basin assessment of CO_2 concentrations of natural gas using data from the scientific literature, as well as company and government reports (for example for the offshore Ichthys field in the Browse Basin that feeds the Ichthys LNG facility). We assume that all extracted CO_2 will be emitted to the atmosphere (except for volumes already captured at facilities equipped with CCUS, which are subtracted from the total).

Estimates of upstream methane emissions intensities for each of the assets were based on country- and type-specific data from the IEA's Global Methane Tracker 2025. These are adjusted to take into account asset-specific information, such as the type of production, the age of facilities, and the type of operator.

Methane emissions also occur during transmission, liquefaction, shipping and regasification. Our emissions from transmission were based on country-specific methane emissions intensities for downstream operations that are scaled to each transmission segment and modelled LNG flows, considering the extent of operating natural gas pipelines. The methane emissions intensity of liquefaction was assumed to be 0.05% (based on satellite data from GHGSat) and regasification was assumed to be 0.02% (based on Innocenti et al 2023). Emissions for shipping reflect ICIS ship tracking data on LNG cargoes, including distance travelled, energy use, type of propulsion engine and average capacity.

Estimates of CO_2 emissions from flaring are based on a detailed review of upstream assets, pipeline connections and data from the World Bank, which provides the volumes and locations of all flares in 2023, as well as country-level assumptions on the liquids content of extracted natural gas. Methane emissions from the incomplete combustion at flares are based on IEA country-level estimates of combustion efficiency.

Our estimates for CO_2 and methane emissions from shipping were based on a detailed bottom-up assessment of fuel use based on the engine type, cargo size and fuel mix of all the ships that carried LNG in 2024. We assumed an average of 4% methane slip for DFDE and TFDE vessels, 2.8% for X-DF and 0.8% for ME-GI.

Estimates of methane abatement costs were based on the IEA Methane Abatement Model, considering emissions sources related to LNG value chains. Details on the methodology are available in the Global Methane Tracker 2025 Documentation including information on abatement options, potential savings, wellhead gas prices and discount rates.

Estimates of flaring reduction costs were based on flare size and distance from existing infrastructure. Revenue from additional gas sales was based on 2024 gas prices. For further information on abatement options and costs, see Emissions from Oil and Gas Operations in Net Zero Transition.

Our estimates of the costs of electrifying liquefaction and upstream facilities is based on detailed geospatial analysis of the location and resources of these assets. Fields that that are likely to stop producing in the next ten years are not considered. For each facility, our assessment examines current and future: upstream energy use, distance from an existing electricity grid, grid connection costs, electricity prices, emissions intensity of electricity, wind and solar potential and costs, and battery costs. The choice of electrifying a site through grid connection or decentralised renewables, and the optimal mix of wind and solar capacity, is based on the option with the lowest net present value in each year.

We welcome all feedback based on measurements and robust data sources that can refine our estimates.

Acknowledgements

We would like to express our gratitude to Japan's Ministry of Economy, Trade and Industry for their support to this work.

The study benefitted from the outcomes of the discussions at the IEA Workshop 'Reducing Emissions from LNG Supply' held in March 2025.

The comments and suggestions of the following experts (in alphabetical order) who provided input and reviewed preliminary drafts of the report were of great value:

Andrea Intieri	Baker Hughes
Benjamin Heras Cruz	Carbon Limits
Calvin Stuckert	Woodfibre LNG
Carmela Chaney	RMI
Craig Duarte	Woodside Energy
Daniel Zavala-Araiza	Environmental Defense Fund
David McCabe	Clean Air Task Force
Dimitrios Pappas	Equinor
Fanny Lagrange	Carbon Limits
Felix Christian Matthes	Öko-Institut - Institute for Applied Ecology
Fiji George	Cheniere Energy
Hiroshi Hashimoto	Institute of Energy Economics, Japan - IEEJ
Jonathan Stern	The Oxford Institute for Energy Studies
Juan Sánchez-Peñuela	Tecnicas Reunidas
Julien Perez	Oil and Gas Climate Initiative (OGCI)
Lahra Liberti	Organisation for Economic Co-operation and Development (OECD)
Laurent David	International Group of LNG Importers (GIIGNL)
Maria Olczak	The Oxford Institute for Energy Studies
Mark Davis	Capterio
Masataka Yarita	Japan Organization for Metals and Energy Security
Masuda Toshihiro	Ministry of Economy, Trade and Industry (METI)
Matt Watson	Watson Public Strategies
Peter Evans	BP
Rossella Palmieri	Baker Hughes
Tomoya Iwaki	Inpex
Yusaku Akamatsu	Mizuho bank
Yvette Manolas	Independent consultant

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Typeset in France by IEA - June 2025
Cover design: IEA
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