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COMPARING THE FUTURE DEMAND FOR, SUPPLY OF, AND LIFE-CYCLE EMISSIONS FROM BIO, SYNTHETIC, AND FOSSIL LNG MARINE FUELS IN THE EUROPEAN UNION

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EXECUTIVE SUMMARY

Liquefied natural gas (LNG) is mostly methane, a potent greenhouse gas that has a global warming potential approximately 30 times greater than carbon dioxide over a 100-year time period and more than 80 times greater over 20 years, according to the Intergovernmental Panel on Climate Change (IPCC). Between 2012 and 2018, the use of LNG as a marine fuel grew 28% globally, resulting in a 150% increase in methane emissions. Previous ICCT work has shown that the unburned fuel in the form of "methane slip" emitted from dual fuel internal combustion engines on ships, combined with the methane leakage that happens throughout the LNG supply chain, can result in higher well-to-wake (WTW) carbon dioxide-equivalent (CO_2e) emissions from ships using LNG compared with conventional marine fuels.

Some people have suggested that LNG can contribute to climate mitigation efforts because these ships can switch to bio and e-LNG ("renewable" LNG) in the future, and they expect that to result in reduced greenhouse gas (GHG) emissions. This assumes (a) that there will be enough renewable LNG in the future to meet demand, and (b) that using renewable LNG in marine engines will result in a substantial reduction in GHG emissions on a life-cycle basis. Understanding whether these assumptions are realistic is important for policymakers, including those in the European Union (EU), which under its "Fit for 55" plan has committed to reducing its GHG emissions by at least 55% below 1990 levels by 2030. The European Union also co-launched the Global Methane Pledge at the 2021 United Nations Climate Change Conference, COP26.

This report estimates demand for LNG used by ships on voyages to, from, and between EU ports in 2030. We then compare the predicted demand to our estimate of the potential supply of renewable LNG and calculate the life-cycle WTW GHG emissions based on using various proportions of renewable LNG. Our estimates show demand for LNG tripling between 2019 and 2030. Because adequate supplies of renewable LNG are likely to be at least seven times more expensive than fossil LNG in 2030, policy support would be needed to create an incentive for its use.

We modeled three policy scenarios whereby the European Union offers a subsidy to use renewable LNG. Each scenario resulted in a different mix of fossil and renewable LNG and therefore different life-cycle CO_2e emissions. Offering no subsidy means that 2030 LNG demand would be met using 100% fossil LNG, which would result in a tripling of WTW GHG emissions from LNG-fueled ships compared to the 2019 level. With a subsidy of 25 euros per gigajoule (€25/GJ), which is the current midrange level of EU policy support for grid-injected biomethane and is equivalent to €1,200 per tonne of LNG, only 4% of LNG demand would be met with renewable LNG and WTW GHG emissions would approximately triple from 2019 levels. Only LNG made using inexpensive landfill gas would be cost-competitive with fossil LNG in 2030 and, unfortunately, this feedstock is in limited supply. Doubling the subsidy to €50/GJ would enable the use of 100% renewable LNG because it would create price parity between more expensive LNG biofuels made from agricultural residues as well as e-LNG. However, this level of price support would require annual public expenditures of €17.8 billion in 2030.

The emissions associated with various 2030 scenarios are shown in Figure ES1. Comparing the scenario in which ships use 100% renewable LNG in 2030 (on the far right in the figure) to the 2019 scenario, where ships used 100% fossil LNG, shows that 2030 WTW CO_2e emissions from LNG-fueled ships would be 38% lower on a 100-year global warming potential (GWP100) basis. However, even with 100% renewable LNG, emissions in 2030 are 6% higher than 2019 levels if considered on a 20-year global warming potential (GWP20) basis.

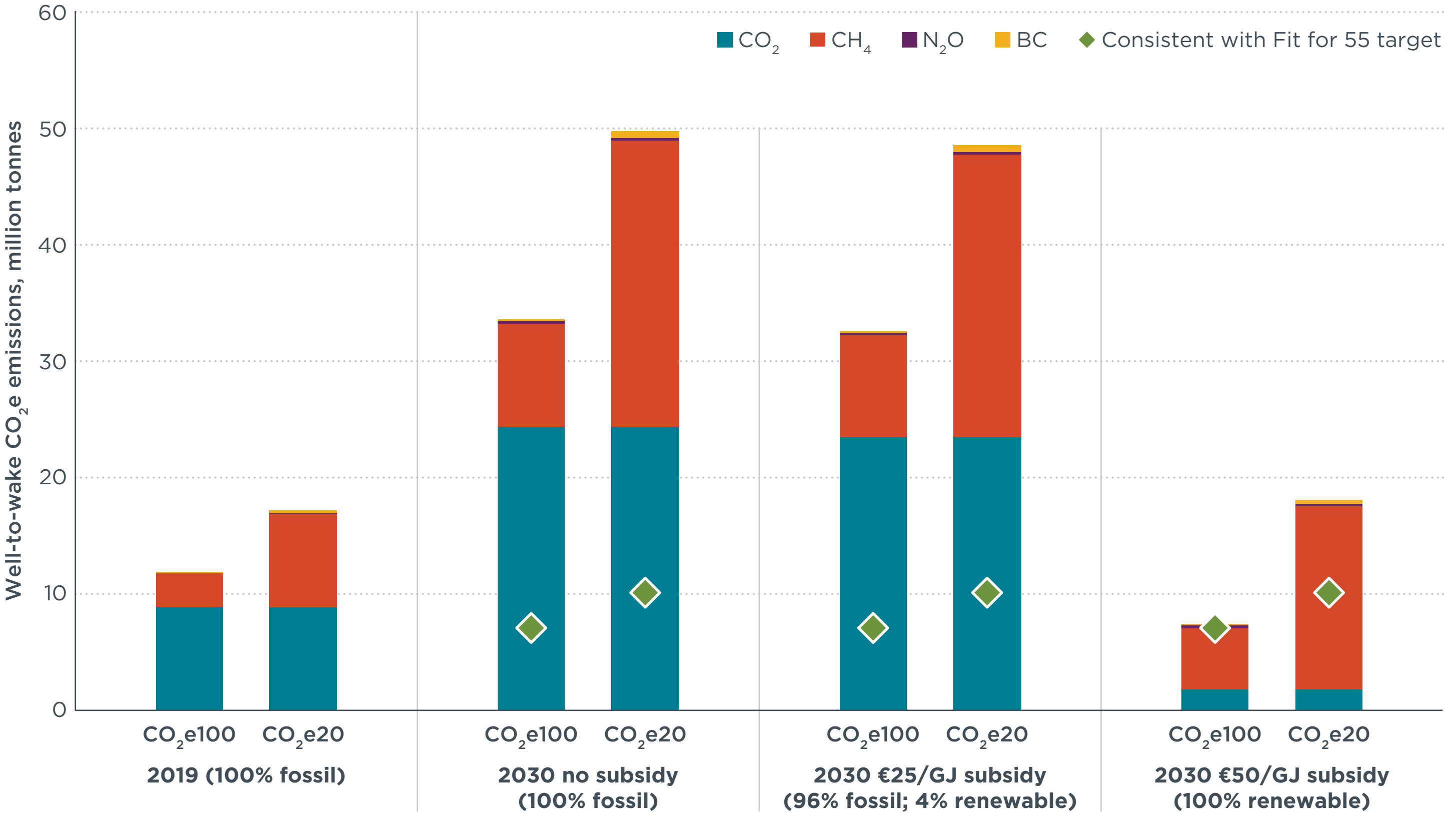

Figure ES1. Comparing the Fit for 55 target, as applied to LNG-fueled ships trading with the European Union, with well-to-wake emissions under three 2030 subsidy scenarios.

Additionally, because of upstream methane leakage and downstream methane slip, even when using 100% renewable LNG, absolute methane emissions would double from 2019 to 2030, as shown in Figure ES2. Meanwhile, the IPCC has indicated that emissions of short-lived climate pollutants such as methane need to be reduced by one-third from 2019 levels by 2030 to limit warming to 1.5°C (IPCC, 2022). Similarly, the Global Methane Pledge aims to reduce methane emissions by 30% between 2020 and 2030.

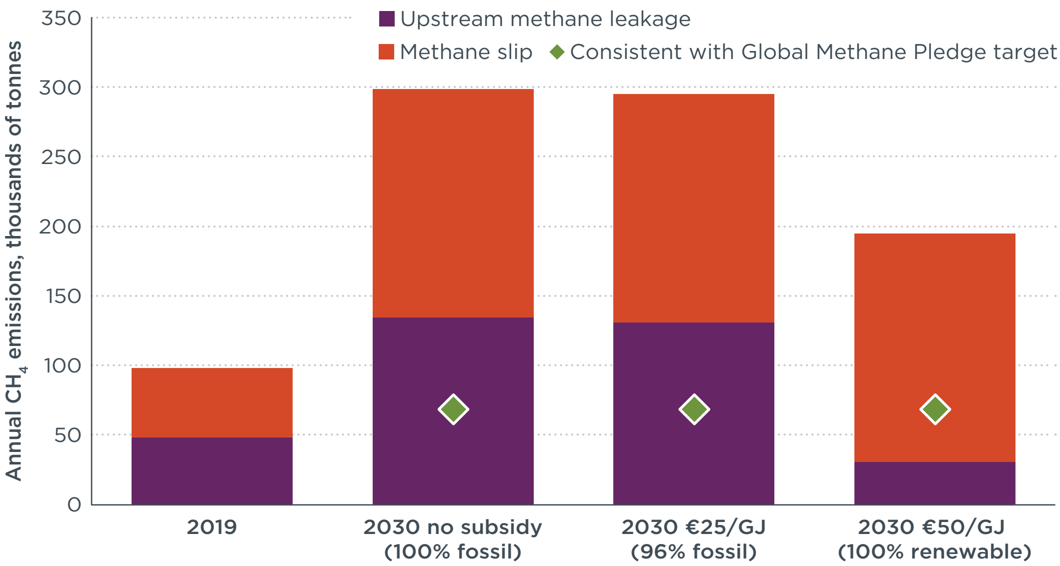

Figure ES2. Comparing the Global Methane Pledge target, as applied to LNG-fueled ships trading with the European Union, with well-to-wake methane emissions under three 2030 subsidy scenarios.

Overall, for renewable LNG to be useful in significantly contributing to climate goals, methane slip from marine engines needs to be virtually eliminated and methane leaks upstream need to be greatly reduced. Additionally, methane leaks from LNG fuel tanks and LNG cargo tanks on ships, which researchers are still working to adequately quantify, would need to be near zero.

It is important for policymakers and all stakeholders to understand that other fuels could offer low life-cycle emissions without the methane problem. Synthetic diesel and green methanol have production costs and technical constraints similar to renewable LNG, but these liquid fuels are easier to store onboard than LNG and could be supplied using existing distribution networks. Synthetic diesel can be used in conventional marine engines or dual fuel engines, including those on existing LNG-fueled ships, and methanol can be used in new or modified dual fuel engines. Future work can focus on the potential demand for and supply of nonmethane fuels to support the transition to zero-emission vessels.

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INTRODUCTION

As of February 2022, there were 1,050 ships in the world that can run on liquefied natural gas (LNG) and more than 700 additional LNG-capable ships on order, according to Clarksons Research Service (2022). This is up from approximately 350 ships in 2012 (Pavlenko et al., 2020). Between 2012 and 2018, global use of LNG as a marine fuel grew 28% and it is estimated that methane emissions from shipping grew about 150% over that period (Faber et al., 2020). This reflects not only the surge in the number of ships burning LNG, but also a trend toward burning LNG in dual fuel internal combustion engines that are currently estimated to allow up to 4.5% of the fuel to escape unburned in the form of methane slip (Pavlenko et al., 2020). Also as of February 2022, by capacity, 15% of new bulk carriers, 30% of new container ships, 40% of new tankers, and 50% of new cruise ships are capable of using LNG (Clarksons Research Service, 2022).

European Union Monitoring Reporting and Verification (EU MRV) data reveals that LNG represented 6.7% of the energy used by ships on voyages to, from, and between EU ports in 2019 (European Maritime Safety Agency, 2021). We expect that share to grow based on the global trends just described. LNG is mostly methane, a greenhouse gas (GHG) that has a global warming potential (GWP) approximately 30 times greater than carbon dioxide over a 100-year time period (GWP100) and 82.5 times greater over 20 years (GWP20), according to the Intergovernmental Panel on Climate Change (IPCC, 2021). It is therefore important to understand the life-cycle GHG emissions from ships using LNG and how that might affect the European Union's ability to achieve its "Fit for 55" target of reducing economy-wide GHG emissions by at least 55% below 1990 levels by 2030. Additionally, the European Union and United States are leading a Global Methane Pledge that aims to reduce methane emissions globally by at least 30% below 2020 levels by 2030.

To justify investments in fossil LNG-fueled ships, some argue that ships can switch to bioLNG or e-LNG made using renewable electricity in the future, and that this will result in low GHG emissions (Keller, 2021). This assumes that there will be enough supply of this renewable LNG to meet demand and that using renewable LNG in marine engines will result in substantial life-cycle GHG reductions. This report investigates these assumptions in the EU shipping context.

We first estimate LNG demand in 2030 and then compare it to the potential supply of renewable LNG that year. We also estimate and compare the well-to-wake (WTW) carbon-dioxide equivalent (CO_2e) emissions from LNG-fueled ships under different scenarios. Renewable LNG is defined in this report as either bioLNG made from wastes such as agricultural or forestry residues or e-LNG made from excess or additional renewable electricity and point-source CO_2.[1] We evaluate WTW emissions using both GWP100 and GWP20.

1 We assume that regulators will treat synthetic fuels made with point source CO_2 as carbon neutral until 2030. To be truly carbon neutral, direct air capture would be needed, but this technology is unlikely to provide enough CO_2 by 2030 to meet demand.

BACKGROUND

Increased interest in LNG as a marine fuel stems from efforts to comply with existing International Maritime Organization (IMO) emissions regulations (Pavlenko et al., 2020). In Annex VI of IMO's International Convention for the Prevention of Pollution from Ships (MARPOL), Regulation 14 limits the sulfur content of marine fuels and Regulation 13 limits nitrogen oxide (NO_x) emissions. Annex VI Chapter 4 includes regulations that limit the carbon dioxide (CO_2) intensity of new ships under the Energy Efficiency Design Index (EEDI) and will begin regulating the carbon intensity of existing ships in 2023 under the Energy Efficiency Existing Ship Index (EEXI) and the Carbon Intensity Indicator (CII). LNG can comply with all of these regulations because it contains only trace amounts of sulfur; has low NO_x emissions when burned in low-pressure injection dual fuel engines, which are the most popular option; and emits about 25% less CO_2 than conventional marine fuels (Pavlenko et al., 2020).

Although fossil LNG complies with existing IMO regulations, methane slip from marine engines and methane leakage upstream in the supply chain can mean higher well-to-wake (WTW) CO_2 emissions compared to conventional marine fuels, especially when used in low-pressure injection dual fuel engines (Balcombe et al., 2021; Lindstad et al., 2020; Lindstad & Rialland, 2020; Pavlenko et al., 2020). Methane slip is highest in low-pressure injection dual fuel (LPDF) engines and lowest in high-pressure injection dual fuel engines (HPDF). The HPDF engines are the most fuel efficient but have high NO_x emissions and usually require exhaust gas aftertreatment to comply with IMO regulations. The aftertreatment technology is one reason why HPDF engines are more expensive to buy and operate than LPDF engines, which have low NO_x emissions but high methane emissions.

Pavlenko et al. (2020) and Faber et al. (2020) found that LPDF engines, especially the 4-stroke versions, are the most popular LNG engine on the market and also have the highest methane slip. In addition to methane slip, methane can leak at multiple points in the fossil gas supply chain, including extraction, distribution, processing, liquefaction, transportation, and fuel bunkering. Previous work has shown that the maximum life-cycle benefit of using fossil LNG as a marine fuel is a 15% reduction in CO_2e emissions on a 100-year timescale compared to marine gas oil (MGO), and only when using the best-in-class engine technology with the lowest methane slip (Pavlenko et al., 2020). Maximizing LNG emissions reductions requires using the most expensive engine option (HPDF) and using LNG produced with low upstream emissions. Accounting for methane's 20-year GWP, the least expensive and most popular marine engine (LPDF, 4-stroke) emits up to 82% more life-cycle CO_2e emissions when running on LNG than when running on MGO, and even the HPDF engine emits 4% more life-cycle GHG emissions than MGO (Pavlenko et al., 2020).

Dual fuel engines can also use bioLNG, which is produced by converting biomass into biomethane, or e-LNG that is made using renewable electricity. In this study, we refer to these collectively as "renewable LNG." However, engines using these fuels still emit the same amount of methane slip, and upstream methane leakage will vary depending on how the fuel is made.

Renewable LNG can be produced from various pathways. These include methane captured from biogenic sources such as landfills and manure digesters as well as e-methane produced by electrolysis. Renewable methane can also be produced by gasifying biomass from the agricultural and forestry sectors to produce syngas in conjunction with methanation. E-methane is also referred to as "power-to-gas" (PtG) and is not yet widely commercialized; because this gas needs to be liquefied for use as a marine fuel, it requires additional energy and there are more opportunities for methane leakage.

Renewable LNG is not yet widely used in the EU transportation sector, but compressed biomethane made by anaerobic digestion is commercially mature in some applications, although ships would need the fuel to be liquefied. The European Biogas Association (EBA) and Gas Infrastructure Europe (GIE) have identified 729 facilities that produce biomethane in the EU and close to 100 sites that make compressed biomethane (European Biogas Association, 2020). Most of this is connected to the EU gas distribution grid for use in the heating, power, and industrial sectors (EurObserv'ER, 2019); however, a small portion is used as transportation fuel. For example, according to Statistics Sweden, about 119,000 tonnes of oil equivalent of renewable natural gas was injected into Sweden's gas grid in 2018, making up 2% of annual road sector energy demand (EurObserv'ER, 2019; Eurostat, 2021a). France is also operating several pipeline-compatible landfill biomethane facilities with the intent to deliver fuel to the transportation sector (Perkins, 2021). Importantly, many of the biomethane facilities across the EU use silage maize, a feed crop that does not provide significant life-cycle GHG reductions, and can sometimes emit just as much as fossil fuels (Kampman et al., 2016; Zhou et al., 2021).

EBA and GIE identified only five facilities that inject renewable LNG into the grid, located in the Netherlands, Norway, and Italy, in their latest gas infrastructure map. This includes a small facility in Italy with 300 m^3/hr capacity that processes agricultural residues into bioLNG (European Food Agency, 2020) and a plant with 10 times that capacity producing bioLNG from fishery waste and paper mill slurry feedstocks (Offshore Energy, 2018). There have been some small-scale trials of using renewable LNG in ships, including shipments operated by UECC, Gasum (Offshore Energy, 2020), and TotalEnergies (2021). These included the use of both blended and 100% drop-in renewable LNG.

Some people have suggested that ships can switch to bioLNG and e-LNG in the future (Keller, 2021). However, despite more than 1,000 LNG-fueled ships on the water today and hundreds more on order, only a few have tested renewable LNG. Supply is limited and there is competition from other sectors, including those that can use the methane as a gas, rather than a liquid, such as those mentioned above. Additionally, as we will show in this analysis, renewable LNG is expected to continue to cost more than fossil LNG and the available supply will depend on the price.

At the 2021 United Nations Climate Change Conference, COP26, the European Union and the United States announced the Global Methane Pledge, with a goal of reducing global methane emissions at least 30% below 2020 levels by 2030 (European Commission, 2021b). More than 100 countries have signed on, but there are no individual responsibilities from any one region. Achieving this goal will require reducing methane emissions from existing sources while preventing or limiting emissions from new sources. Additionally, EU law requires reducing economy-wide GHG emissions at least 55% below 1990 levels by 2030 (European Council, 2020). As of 2019, the European Union has already reduced its emissions by 24% (European Commission, 2020), and that means that achieving its 2030 goals requires an additional 31 percentage point reduction in GHGs from 2019 levels by 2030. That is equivalent to a 41% reduction from a 2019 baseline by 2030. Moreover, the European Union will seek to reduce emissions from both domestic and international shipping by adding shipping to the EU Emissions Trading System (ETS) in 2023 and by gradually reducing the life-cycle GHG emissions of marine fuels starting in 2025 through the FuelEU Maritime initiative. The extent to which using renewable LNG instead of fossil LNG could help achieve the European Union's goals will depend on how it is produced, the engines in which it is used, and the amount of 2030 LNG demand it can satisfy.

LITERATURE REVIEW

This analysis relies on an estimate of 2030 LNG demand from ships that sail to, from, and between EU ports and an estimate of renewable LNG supply in the European Union in 2030. We therefore spend considerable time in this section reviewing the literature related to these topics. We also periodically reference our own estimates of demand and supply that are detailed in the Results section, as this illuminates how our current study fits within the literature.

LNG DEMAND

Estimates of global demand for LNG as a marine fuel are more readily found in the literature than EU-specific estimates. Several research groups have estimated global marine LNG demand for 2030 under different economic and policy scenarios. A selection of these is summarized in Figure 1, which shows a range of 300–2,470 petajoules (PJ) in 2030. For this analysis and as detailed in the Methods section, we estimate that LNG demand for the global fleet in 2019 was 628 PJ. As such, the literature suggests that LNG demand for ships in 2030 could range from as little as half the 2019 demand to as much as four times that amount. For global demand for LNG used in ships, we arrived at an estimate of 1,738 PJ in 2030, and that is shown by the red X on Figure 1. Our predicted demand falls in the upper third of the range in the literature.

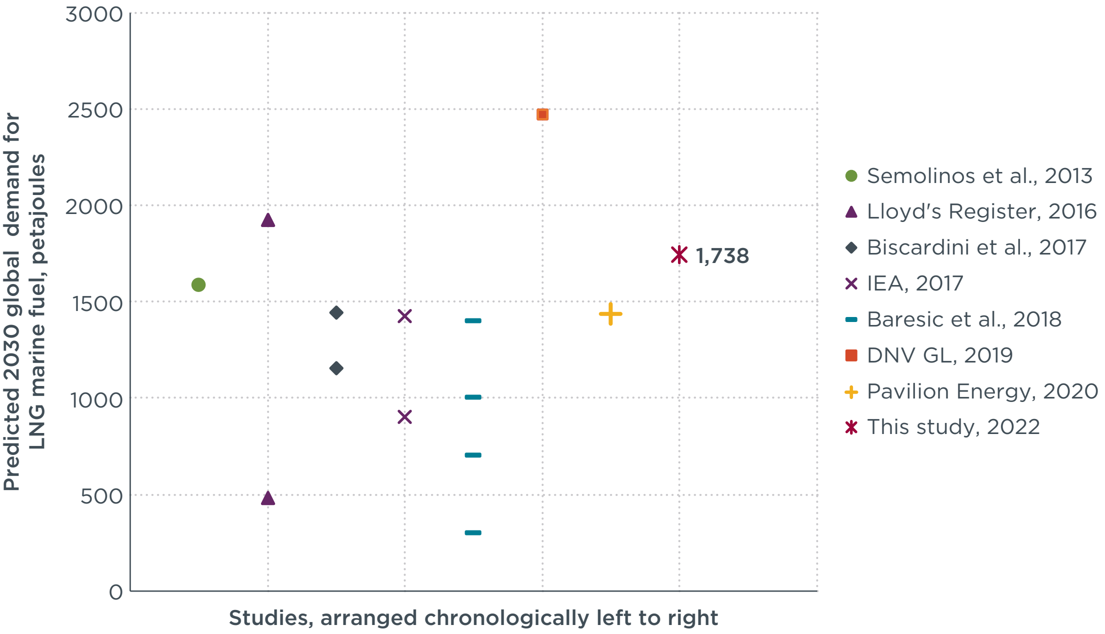


Figure 1. Comparing predicted 2030 global demand for LNG marine fuel from the literature to this study (red x).

Baresic et al. (2018) considered four LNG-demand scenarios for 2030, each assuming different future fuels options and different carbon market-based measures combined with out-of-sector offsets. The business-as-usual (BAU) scenario considered existing environmental regulations, but without any additional policy developments or market-based measures; the scenario assumed low biofuel availability and no hydrogen uptake in the future fleet. Therefore, the BAU scenario predicted the highest LNG demand, about 1,400 PJ. The predicted LNG demand for the three other scenarios (high gas, limited gas, and transition) assumed market-based measures, although the market-based carbon price assumptions were not stated in the study. The carbon budget for the scenarios was based on staying below 2°C of warming above preindustrial levels (33 gigatonnes of CO_2 remaining from 2010 onward). The start year of the market-based measures varied: In the high gas and limited gas scenarios, market-based measures started in 2025 and 30% of the carbon revenue could be offset out of sector. The high gas scenario excluded hydrogen uptake and assumed low biofuel availability and low LNG prices. The predicted LNG demand for this high gas scenario is approximately 1,000 PJ. The limited gas scenario, on the other hand, assumed mid-range biofuel availability, and that hydrogen and oil would be in the fuel mix in 2030. The predicted LNG demand for the limited gas scenario is about 300 PJ. Finally, in the transition scenario, market-based measures started in 2030 and 20% of the carbon revenue could be used to offset out of sector. It assumed a low hydrogen price and low biofuel availability in the future, and the predicted LNG demand for this scenario is approximately 700 PJ.

Lloyd's Register (2016) projected a set of scenarios based on different trends in economic and population growth, resource accessibility, and technology developments. The study explored several pathways including a BAU scenario, scenarios with high hydrogen availability, high bioenergy availability, and a high offsetting scenario. Thus, the BAU scenario did not include any offset allowances, the high bioenergy scenario assumed 202 million tonnes (Mt) of CO_2 being purchased from other sectors by 2050, and the high hydrogen and high offsetting scenarios assumed 318 Mt and 490 Mt of CO_2 offsets, respectively. The 2030 demand predictions were in the range of 10 to 40 Mt LNG, equivalent to 480 to 1,920 PJ.

PwC's Biscardini, Schmill, and Del Maestro (2017) forecasted 2030 marine LNG demand based on assumptions of differences in prices between LNG and oil (low, medium, and high scenarios). The study estimated values in the range of 24 to 30 Mt LNG per year by 2030, equivalent to 1,150 to 1,440 PJ, but it excluded LNG fuel consumption by LNG carriers, which accounts for the most LNG use of any ship type (Faber et al., 2020).

The International Energy Agency (2017) considered two types of LNG demand growth by 2030: a sustainable development scenario (18.8 Mt or 902 PJ) and a new policies scenario (29.7 Mt or 1,430 PJ), and both exclude LNG carriers. The sustainable development scenario reflects the United Nations' sustainable development goals and suggests equal global access to the new advanced technologies and dedication to climate change actions. The new policies scenario is based on the global assessment of national strategies and policies affecting natural gas production, pricing, and demand. Both scenarios considered 3.4% of world economic growth, translated into country-specific energy demand growth. Natural gas prices were projected by using the integrated global gas market model, where regional price changes in supply and demand affect the global price. The sustainable development scenario predicted LNG demand growing 0.6% per year with a plateau in 2030 due to energy efficiency improvements; the 2030 demand estimate was 18.8 Mt LNG, or 900 PJ. The new policies scenario implies a 1.6% increase in annual LNG consumption resulting in 29 Mt LNG, or 1,430 PJ, by 2030.

In Pavilion Energy (2020), the expected LNG demand in 2030 reached 30 Mt or 1,440 PJ per year. A similar LNG demand prediction was made by Semolinos (2013): 33 Mt or 1,580 PJ by 2030. This scenario assumed gradual LNG uptake wherein LNG use first increases only for short-sea shipping when ships are operating in sulfur emission control areas and is slowly followed by deep-sea shipping applications. The authors noted that if economies of scale make the LNG transition cost effective, the deep-sea market would develop faster than they assumed.

DNV GL (2019) predicted the highest LNG demand by 2030, equivalent to 2,470 PJ. This future scenario was developed under the assumption that the GHG reduction targets developed by the IMO would be met through ship energy efficiency improvement and new fuels uptake. This transitional model predicted that global maritime transport would increase by 39% by 2050 compared to 2018. Fossil LNG's share was predicted to be 41% of the 2050 fuel mix, and DNV GL assumed no large use of renewable methane. Ammonia was assumed to reach 25% of the future fuel energy mix, and the remaining 34% of the demand was shared among heavy fuel oil (HFO) with scrubbers (10%), low-sulfur fossil fuels (9%), electricity (7%), biodiesel (4%), hydrogen (1%), LPG (1%) and renewable methane (2%).

Only a limited number of publications are available on future LNG demand in Europe. Faber et al. (2015) conducted a comprehensive analysis of future LNG demand, supply, and infrastructure developments for the intra-EU LNG-compatible fleet. The authors explored a range of policy scenarios, with differing assumptions for the LNG-compatible fleet size and gross domestic product (GDP) growth. The "low" prediction scenario assumed no future economic growth and less than 1% growth in cargo transport work. This model predicted that LNG consumption by 2030 would range from 10 to 50 PJ and the share of LNG in total fuel consumption would be 2%–10%. The "maximum" scenario implied high GDP growth and corresponding growth in cargo transport work. Additionally, it assumed that the LNG-compatible fleet would increase by 3% annually. The maximum scenario predicted a range of 180–310 PJ by 2030, and a 30%–50% share for LNG in total fuel consumption.

Baresic et al. (2018) estimated future LNG demand under four scenarios, as described above. For EU-related LNG consumption, the study estimated a range of LNG energy use of approximately 130 PJ in the "limited gas" scenario, roughly 300 PJ in the "transition" scenario, about 500 PJ in the "high gas" scenario. In an analysis of the potential fuel mix impacts of the FuelEU Maritime proposal, Transport & Environment (2021) estimated potential fossil LNG demand if the FuelEU Maritime initiative were to cover 100% of fuel consumption for inbound, outbound, and intra-EU voyages. (The current scope of FuelEU Maritime is 50% of inbound and outbound fuel consumption and 100% intra-EU.) Transport & Environment (2021) predicted that ships on voyages to, from, or between EU ports would consume 7 Mt of LNG, or about 336 PJ, in 2030. This would represent 18% of the total energy demand for covered voyages. Transport & Environment published an updated analysis which estimated 6.6 Mt of LNG demand for the current scope of FuelEU Maritime (100% intra-EU and 50% inbound and outbound fuel consumption); that is equivalent to 9.3 Mt (446 PJ) if it were to apply to 100% of inbound and outbound fuel consumption (Transport & Environment, 2022).

In the results detailed in the following sections of this report, we predict 2030 demand for LNG for ships on voyages to, from, or between EU ports at 356 PJ (7.42 Mt LNG), which covers 100% of inbound and outbound fuel consumption.

RENEWABLE LNG SUPPLY

We defined renewable LNG as those quantities coming from certain bio and synthetic pathways. For synthetic renewable LNG (e-LNG), we assumed it must be made from excess or additional renewable electricity and point source CO_2. Although the supply of e-LNG is theoretically unlimited, in reality the limiting factor is the cost of producing the fuel. Current production of e-LNG globally and in the EU is essentially zero (Nelissen et al., 2020), and sources of point source CO_2 can be expected to decline over time as other sectors of the economy decarbonize. Thus, reaching greater volumes of e-LNG in later years might necessitate direct air capture (DAC).

Regarding biomethane, various studies have estimated 2030 supply. Nelissen et al. (2020) investigated global biomethane availability in relation to maritime shipping demand, but competition among sectors for biomass resources was not considered in the maximum supply estimates. In total, Nelissen et al. estimated that between 40,000 and 120,000 PJ of biomethane could be sustainably sourced globally from agricultural residues, forestry products and residues, and purpose-grown energy crops. In the study, sustainable sourcing was loosely defined as not "interfering with the growth of food, fodder, and fibres" (p. 5). To estimate maximum supply, Nelissen et al.'s estimate drew from multiple other reports, including the International Renewable Energy Agency's (IRENA) predictions concerning sustainable biomass potential in 2030. IRENA (2014) predicted between 18,000 and 36,000 PJ per year of available sustainable biomass in Europe alone, much higher than current biomethane production levels. As of 2018, EU biogas production was 16.8 million tonnes of oil equivalent, or 705 PJ (EurObserv'ER, 2019). Because biogas is only about 60% biomethane on an energy basis, this is equivalent to 433 PJ of biomethane; liquefying biomethane for use in marine further reduces the final energy available.

There are several other biomethane supply estimates for Europe. In late 2016, the European Commission convened a study to assess biogas potential from anaerobic digestion in the EU beyond 2020 (Kampman et al., 2016). Feedstocks assessed included sewage sludge, manure, energy crops, municipal solid waste (MSW), and agricultural residues. Kampman et al. estimated between 1,200 and 1,680 PJ of biogas potential in 2030 under various growth scenarios. These availability estimates are higher than current biogas consumption rates in the EU and assumed growth driven by policy commitments and financial support. At the feedstock level, increased use of anaerobic digestion to treat manure is expected to generate higher levels of biogas production.

The industry group Gas for Climate also commissioned a study to assess renewable methane production potential in a 2050 time frame (van Melle et al., 2018). This study estimated that up to 122 billion cubic meters (bcm) of renewable methane, equivalent to 4,370 PJ, could be produced in 2050, including 98 bcm (3,510 PJ) from biomethane and the remainder e-methane. The high biomethane potential presented in Gas for Climate's analysis contrasts with an ICCT study, Baldino et al. (2018), which estimated renewable methane availability in the European Union for use in the heating, power, and transport sectors. Combining feedstock availability data from the European statistical database, Eurostat, and pathway-specific economic and yield data from the literature, Baldino et al. estimated 29 bcm (1,040 PJ) of renewable biomethane potential in 2050, less than a third of the van Melle et al. estimate.

The largest differences between the two studies concern assumptions about the rate of deployment of biomethane processing facilities and double cropping. Baldino et al. (2018) found facility deployment to be the limiting factor in 2030 feedstock availability estimates whereas van Melle et al. (2018) assumed all available feedstock could be processed in this time frame. Additionally, although van Melle et al. assumed high potential for double cropping, there is evidence from the literature that this level of expanded crop production is infeasible (European Commission, Directorate General for Agriculture and Rural Development, 2017). Regarding double cropping, outside the EU, especially in regions with multiple growing seasons, intermediate crops are often grown as cash crops and thus they are associated with the same land-use change emissions as primary food and feed-based crops. For example, in Brazil, winter corn, which could be considered an intermediate crop, is grown as a cash crop (Malins, 2022).

Baldino et al. (2018) also contained EU renewable methane availability estimates for 2030. Assuming no cost constraints, the authors estimated 17.5 bcm (630 PJ) of renewable methane potential in 2030. However, considering cost constraints reduces estimates of availability. With 1.75 €/m^3 of policy support, which is equivalent to nearly 50 €/GJ, this potential reduces to 4.2 bcm (150 PJ). Current policy support for biomethane injection into the natural gas grid in the European Union includes feed-in tariffs in France and Italy. The level of support varies by the size and type of facility; in France, feed-in tariffs are roughly equivalent to €0.045–€0.125 per kWh of biomethane injected to the gas grid, which is equivalent to €13–€35/GJ (Eden, 2018).

Nelissen et al. (2020) estimated biomethane production costs but did not apply a limiting cost factor. The authors estimated that current biomethane production costs range between $20 and $50 per million British thermal units (MMBtu) (€15–€40/GJ) for anaerobic digestion and between $25 and $65/MMBtu (€20–50/GJ) for gasification pathways. They also assumed that gasification costs would decrease dramatically over time, down to $13/MMBtu (€10/GJ) in 2050. For e-methane, the authors estimated that costs range between $23 and $110/MMBtu (€20–€85/GJ) depending on local electricity prices and electrolyzer loads.

METHODS

ESTIMATING DEMAND FOR FOSSIL LNG

To estimate 2019 LNG consumption by ships on voyages to, from, and between EU ports, we used data from the EU Monitoring, Reporting and Verification (MRV) dataset provided by the European Maritime Safety Agency, THETIS-MRV (European Maritime Safety Agency, 2021). The EU MRV reports fuel consumption for ships greater than 5,000 gross tonnage (GT) for voyages that begin or end at an EU port. Although fuel consumption is reported in the EU MRV, it is not broken down by fuel type. To estimate the amount of LNG consumed by ships in the EU MRV database, we first identified LNG-compatible ships using the ICCT's SAVE model (Olmer et al., 2017). We found 294 LNG-capable ships in the EU MRV dataset in 2019, 211 of which were dedicated LNG carriers; we additionally found 32 gas carriers capable of carrying LNG and other liquefied gases such as liquefied petroleum gas, 13 chemical tankers, 10 roll-on/roll-off passenger ships, nine oil tankers, eight container ships, and several other ship types including passenger ships and vehicle carriers. The SAVE model uses information from the IHS dataset to predict the fuel that ships typically use. Some LNG-capable ships might not always use LNG, and they also might use a different fuel type as a pilot fuel, in auxiliary engines, or in boilers.

For modeling purposes, we assumed that all fuel consumption from LNG-capable ships is LNG. To be sure that most LNG-capable ships were mainly using LNG, we used the fuel consumption and CO_2 emissions reported in the EU MRV database (European Maritime Safety Agency, 2021) to calculate the implied carbon conversion factor of the fuel; this was done by dividing the total CO_2 emissions by total fuel consumption. LNG has a carbon conversion factor of 2.75 grams of CO_2 per gram of fuel (CO_2/g fuel). Conventional marine fuels such as heavy fuel oil and marine gas oil have carbon conversion factors of 3.114 gCO_2/g fuel and 3.206 gCO_2/g fuel, respectively. Figure 2 shows that, of the 294 LNG-capable ships in the EU MRV database, 200 ships representing 70% of 2019 fuel consumption by LNG-compatible ships had a carbon conversion factor between 2.75 and 2.85 gCO_2/g fuel. These ships were very likely using LNG as their primary fuel, with MGO as a pilot fuel. Twenty-eight ships, representing 20% of fuel consumption, had a carbon conversion factor between 2.85 and 2.95 gCO_2/g fuel. These ships primarily use LNG but might also use MGO or HFO when LNG is not available or when fuel prices favor non-LNG fuels. The remaining 40 ships, representing 10% of fuel consumption from LNG-capable ships, had a carbon conversion factor greater than or equal to 2.95 gCO_2/g fuel. This implies that these ships used some LNG but often used other fuels. One ship had a carbon conversion factor of 3.206, meaning that it would have used only MGO in 2019. Overall, we found that most LNG-capable ships tended to use LNG as their primary marine fuel.

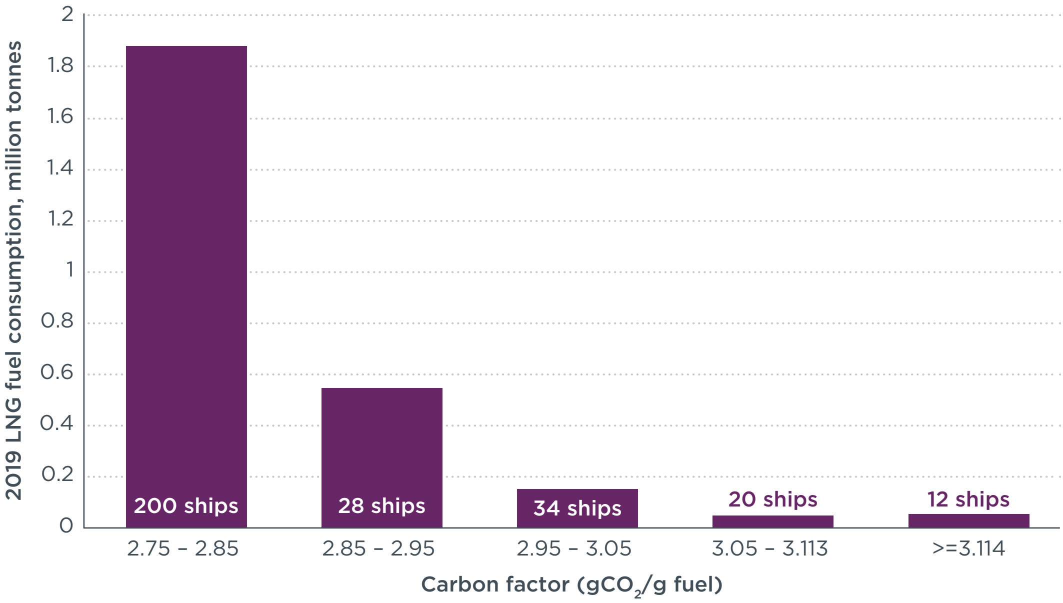
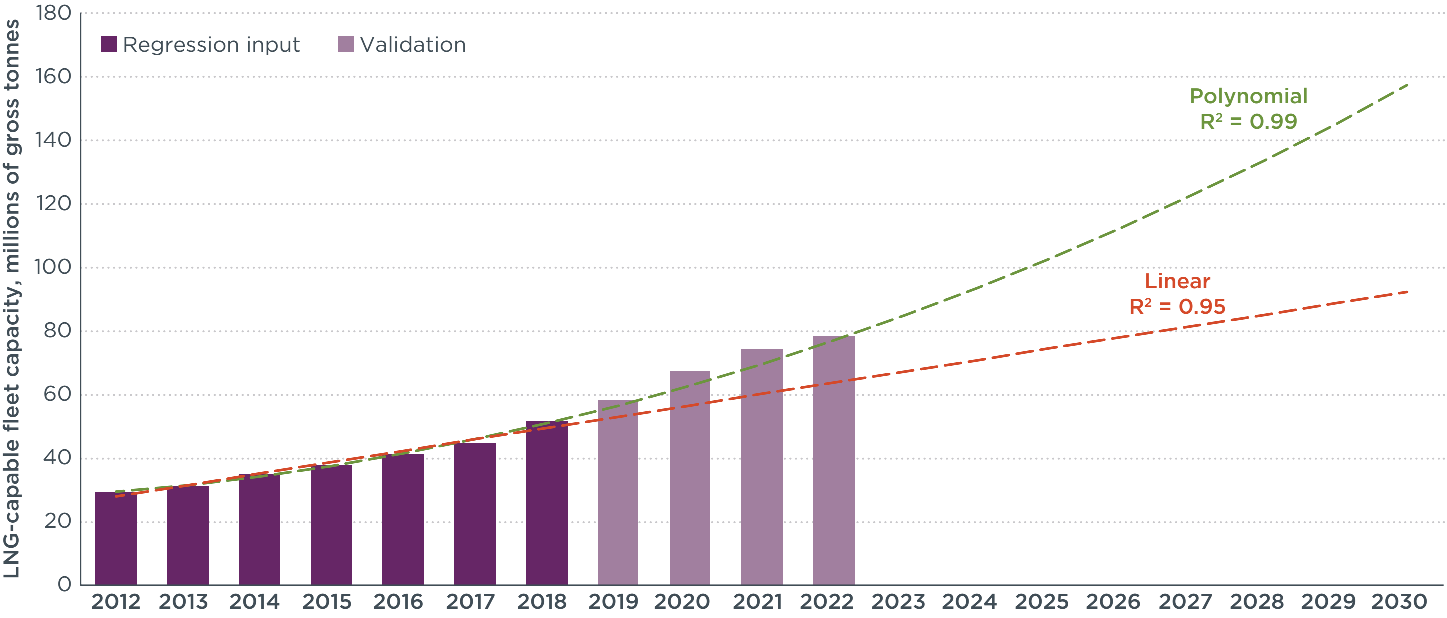


Figure 2. Calculated fuel carbon factor of LNG-capable ships in the 2019 EU MRV dataset.

To predict 2030 LNG demand, we examined the historical relationship between gross tonnage of the LNG-fueled fleet and LNG demand. The LNG-fueled fleet grew from 38 million GT in 2015 to 52 million GT in 2018 (IHS Markit, 2021), while LNG consumption grew from 8 Mt to 12 Mt during the same period, according to the *Fourth IMO Greenhouse Gas Study* (Faber et al., 2020). During the same period, the relationship between the LNG consumption from the *Fourth IMO Greenhouse Gas Study* and GT from IHS Markit ranges from 0.21–0.23 t LNG/GT. For 2019, the ICCT SAVE model estimates 0.23 t LNG/GT.

To estimate the gross tonnage of the LNG-compatible fleet in the 2030, we considered two projection options: linear growth and polynomial growth. The gross tonnage of the LNG-compatible fleet is known for the years 2012 to 2022 based on historical (2012 to 2020) and orderbook (2021 and 2022) data from IHS. Figure 3 shows the linear and polynomial best fit lines to these data. We used 2012–2018 data as inputs to the regression models and 2019–2022 data as a validation set. Overall, both models have a good fit ($R^2 > 0.95$). Using the IHS GT values for 2019–2022 as a validation set, we compared the GT predicted values from both models. The mean squared error (MSE) for the linear model prediction was 141, while for the polynomial model, the MSE was 13. We therefore proceeded with the polynomial GT growth assumption. The predicted 2030 GT from the polynomial model was 157.4 million GT. We multiplied that value by 0.23 t LNG/GT, which is consistent with the relationship we observed in the *Fourth IMO Greenhouse Gas Study* data, IHS Markit, and SAVE models for recent years, to estimate a global 2030 LNG demand of 36.2 Mt.

To estimate 2030 EU demand for LNG, we assume that the 2019 ratio of EU-related LNG consumption in the MRV and global LNG consumption from ICCT's SAVE model remains constant. According to ICCT's SAVE model, global demand for LNG marine fuel was 13.08 Mt in 2019. That is equivalent to 628 PJ if assuming an energy density of 48 MJ/kg, consistent with Faber et al. (2020). Ships on voyages to, from, and between EU ports used about 2.68 Mt of LNG in 2019 according to EU MRV data (European Maritime Safety Agency, 2021). This implies that voyages by LNG-fueled ships that begin or end at an EU port or travel between two EU ports account for 20.5% of global shipping's LNG consumption.



Note: Dark purple bars show historical data used as the regression input data; light purple shows a mix of historical (2019 and 2020) and orderbook (2021 and 2022) data used to validate the models.

Figure 3. Predicted size of the LNG-compatible fleet under linear and polynomial growth assumptions; polynomial growth was selected to predict future LNG demand for this analysis.

In addition to understanding 2019 and 2030 demand for LNG, it is important to estimate the share of LNG consumption by engine type. Different engine technologies have different methane slip emission factors, and this affects the direct and life-cycle (WTW) CO_2e emissions from using LNG as a marine fuel. LNG-fueled ships can use the following engine technologies:

» Slow-speed, two-stroke, high-pressure injection, dual fuel (HPDF)

» Slow-speed, two-stroke, low-pressure injection, dual fuel (LPDF, 2-stroke)

» Medium-speed, four-stroke, low-pressure injection, dual fuel (LPDF, 4-stroke)

» Lean-burn, spark-ignition, mono fuel (LBSI)

» Steam turbine

To estimate 2019 fuel consumption by engine type, we relied on the ICCT SAVE model, which uses the same engine classification system as the *Fourth IMO Greenhouse Gas Study*, in combination with the EU MRV data. The SAVE model estimates annual fuel consumption ship-by-ship and contains information on the engines that each ship uses. From the 294 LNG-capable ships in the EU MRV data previously described, we identified their engine technology in SAVE based on their IMO numbers. (Recall that we assumed that all the fuel consumption for these ships reported in the EU MRV database was LNG.)

For 2030, we predicted the proportion of LNG consumption by engine type based on trends in the share of LNG consumption by engine type reported in the *Fourth IMO Greenhouse Gas Study* (Faber et al., 2020). The *Fourth IMO Greenhouse Gas Study* reported the proportion of LNG fuel consumption by engine type for 2012–2017, as shown in Figure 4. We calculated the best-fit logarithmic trend for each engine type. The trend shows that the use of LNG in steam turbines, which are far less efficient than internal combustion engines but have very low methane slip, is falling over time, while use of LNG in internal combustion engines is growing. Steam turbines represented 73% of LNG fuel consumption in 2012, but only 43% by 2017, and we expect them to account for just 26% of LNG consumption by 2030. The LPDF, 4-stroke engine accounts for the greatest fuel consumption for internal combustion engines, growing from 20% in 2012 to 40% in 2017; we expect its share to continue to grow but at a slower pace, accounting for approximately 54% of LNG fuel consumption by 2030.

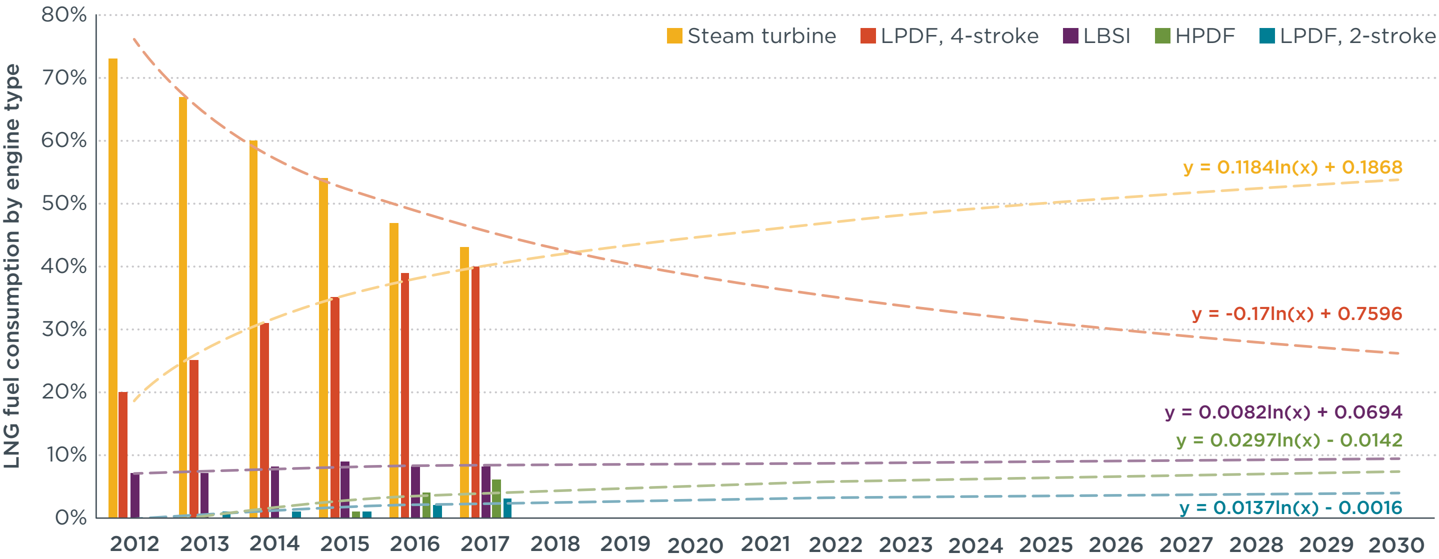


Figure 4. Share of LNG fuel consumption by engine type, 2012–2017, with best-fit logarithmic trend lines used to predict 2030 LNG fuel consumption by engine type.

For the rest of the internal combustion engines, we predict that the share of LNG consumption in LBSI engines will increase from 1% to 9%. For HPDF engines, which are the internal combustion engines with the lowest methane slip, their share grew from 1% in 2015 to 4% in 2016 and 6% in 2017; we expect their share to increase, but only to a bit more than 7% by 2030 because this is the most expensive engine technology and requires exhaust aftertreatment to comply with the IMO Tier III NO_x standards that apply in the Baltic Sea and North Sea Emission Control Areas for ships built in 2021 or later. The share of LNG use in HPDF engines could grow if methane is regulated at the EU or international level. LPDF, 2-stroke engines grew from 1% of LNG consumption in 2015 to 3% in 2017, and we predict that their share will reach 4% by 2030. This may prove to be an underestimate if larger ships such as mega container ships continue to invest in these engines; however, there is also strong growth in the LNG carrier segment, which accounted for nearly 80% of LNG consumption in the 2019 EU MRV dataset, and these ships tend to use LPDF, 4-stroke engines. This growth could shift the share of LNG consumption toward the 4-stroke LPDF engines, even if absolute LNG consumption in the 2-stroke LPDF engines grows.

The estimated change in LNG fuel consumption by engine type from 2019 to 2030 is shown in Figure 5. Note that, by 2030, ships using LPDF 4-stroke and LBSI engines might not comply with 2030 FuelEU Maritime carbon intensity regulations if they use 100% fossil LNG at all times. However, as the investments in these engines have largely already been made, we expect that ships will continue to use these engines in the EU in 2030. To comply with FuelEU Maritime, ships with these engines could do any of the following: blend fossil LNG with bioLNG or e-LNG if those fuels have lower WTW CO_2e emissions; use other bio or e-fuels that have lower WTW CO_2e emissions for a portion of the time if the ship has a dual fuel engine; use banked compliance credits from earlier years; or purchase credits from overperformers. In this analysis, we assumed that ships continue to use 100% fossil LNG in 2030 and used banked compliance credits or purchased credits from others.

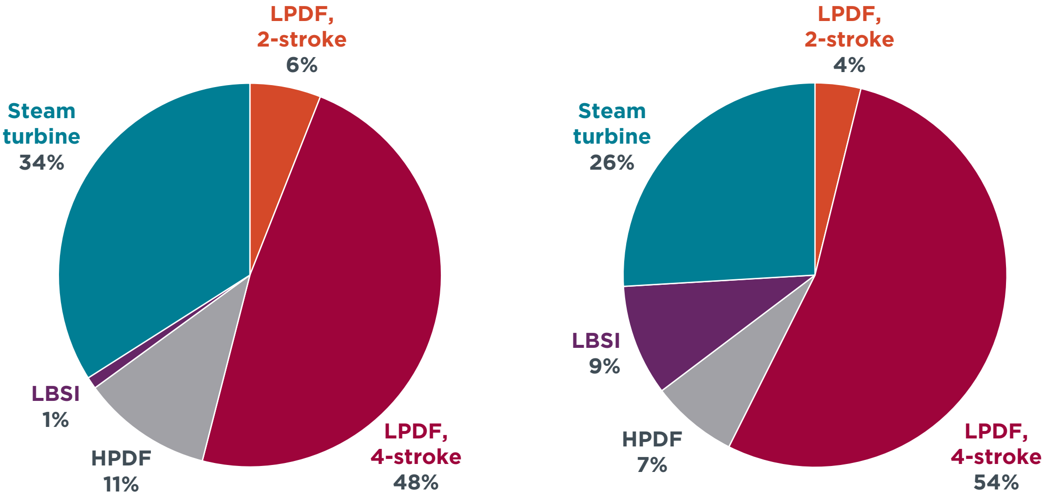


Figure 5. LNG fuel consumption by engine type for ships on voyages to, from, and between EU ports in 2019 (left) and predicted for 2030 (right).

ESTIMATING SUPPLY OF BIOLNG AND E-LNG

We estimate the supply of renewable methane pathways in 2030 including landfill gas (LFG), manure and sewage biogas, agricultural and forestry residues, and e-LNG using hydrogen produced via electrolysis. The majority of our feedstock supply assumptions and data are drawn from Baldino et al. (2018), with the exception of LFG. We use biomass availability estimates from Carraro et al. (2021), which updated the Baldino et al. study by adjusting several assumptions including the types of agricultural residues used, consumption in other end-uses, and projected crop yields in 2030. Carraro et al. also updated forestry residue availability estimates based on annual bioenergy demand data and roundwood harvesting practices by EU member states. In this analysis, biomethane potential from anaerobic digestion of sewage sludge and livestock manure was calculated using the same methodology as Baldino et al. In total, our supply estimates include 83 Mt of agricultural residues, 11 Mt of forestry residues, and 10.3 bcm of sewage and manure biomethane.

Unlike Baldino et al. (2018), our bioLNG supply estimates assume that biomethane currently used in other end-use sectors such as heat and electricity is not available for use as a transportation fuel. Further, we apply a constraint on feedstock quantities already reserved for the aviation sector under the European Commission’s ReFuelEU Aviation initiative blending targets (European Commission, 2021c). The total quantity of available biomass diverted to the aviation sector is based on a study conducted on EU biomass availability for sustainable aviation fuel (O’Malley et al., 2021). After applying these constraints, we assume that the remaining biomethane could be used in the marine sector. This does not account for the small quantity of biomethane that is already used in natural gas vehicles in on-road fuel applications (IRENA, 2018). We also did not factor in any facility deployment ramp-up times and collection constraints.

Unlike the Baldino et al. (2018) study, we assumed biomethane produced from MSW is sourced from anaerobic digesters located at landfills rather than the costlier method of waste gasification. Methane capture at landfills has become commonplace throughout the EU as a result of waste reduction strategies such as the Landfill Directive (Council Directive 1999/31/EC on the Landfill of Waste, 1999) and Waste Framework Directive (Council Directive 2008/98/EC on Waste and Repealing Certain Directives, 2008).

We drew from Kampman et al. (2016) to estimate total LFG availability in 2030. This estimate accounts for a significant reduction in landfilling due to policy drivers such as the Landfill Directive. We also assumed that LFG volumes currently used for on-site electricity production are not upgraded and diverted to the marine sector, which reduces our supply estimates by roughly 80%.

Additionally, we assumed that all landfills are equipped with collection systems complying with Article 4.2 of the Waste Framework Directive. Under the directive, both facilities that use gas for energy recovery or biogas upgrading and facilities that flare gas must install well heads to capture released methane. Although there might be several older or small-volume landfills that do not comply with the directive, we did not find any evidence of major noncompliance or "unsanitary" systems in operation today. The Landfill Directive also set a goal to reduce the landfilled share of MSW to a maximum 10% in 2035. Achieving Landfill Directive source reduction targets will substantially reduce the volume of LFG available for biomethane production. However, because organic waste decays exponentially over time, material already deposited in landfills will continue to release methane up to 30 years beyond its landfilling date (Kampman et al., 2016). Thus, LFG availability increases marginally through 2030.

We did not estimate e-LNG supply because its availability is theoretically unlimited. However, there are competing demands for renewable resources, and additional electricity demands from PtG facilities could lead to the diversion of electricity from the central grid. As a result, renewable electricity used to power PtG operations could lead to an increase in fossil-powered generation elsewhere in the system. Ensuring that e-LNG is produced from electricity that is both renewable and additional is critical for avoiding any unintended GHG emissions impacts (Malins, 2019). The potential for e-LNG production to meet transport sector fuel demand will depend on cost constraints and policy incentives; policy intervention is likely to be necessary to bridge the cost gap between e-methane and conventional fuels and scale up the industry.

ESTIMATING COST OF FOSSIL, BIO, AND E-LNG

For fossil LNG, DNV's Alternative Fuels Insight platform estimates fossil LNG prices for use in the maritime sector based on the Dutch natural gas market, called the Title Transfer Facility.[2] Between 2015 and 2019, the price of LNG, as estimated by DNV, ranged from approximately €200 to €400 per tonne (t) (approximately €4.2/GJ to €8.3/GJ). In 2021, fossil LNG prices reached record highs, and the port of Rotterdam charged approximately €1,400/t LNG (€29/GJ) on February 1, 2022, which reflects increased demand paired with limited supply and expensive shipping rates; the latter are connected with the pandemic and supply chain issues (Jaganathan, 2021). It is difficult to predict future LNG prices, and here we assumed that by 2030, the price of fossil LNG returns closer to pre-pandemic levels. We assumed a 2030 fossil LNG price of €350/t, equivalent to €7.3/GJ, toward the high range of the 2015–2019 average.

To estimate the cost of bio and e-LNG, we drew upon cost data from Baldino et al. (2018) for much of our analysis, with the exception of MSW. For each biomethane production pathway, Baldino et al. calculated the level of financial incentive needed to achieve a net present value of zero, also known as the minimum selling price. We added an additional cost of €2.00/GJ to the set of biomethane cost estimates from Baldino et al. to account for the additional costs of liquefaction. Liquefaction costs are based on industry data reported by a U.S.-based natural gas company Cheniere Energy (Weber & Wyeno, 2020); we assumed that the costs for liquefaction in the EU would be similar.

The cost of bioLNG varies by pathway. For the MSW pathway, we assumed that it is highly likely that methane will be generated via landfill gas collection at existing landfills rather than gasification, due to the high costs and technological immaturity of the latter pathway. Landfill gas collection costs were estimated using a discounted cashflow model based on the upfront capital costs of LFG collection and compression

2 https://www.dnv.com/services/alternative-fuels-insight-128171

equipment, operating costs of labor, overhead and utilities, and pipeline installation and interconnection costs. Most data used to develop this LFG discounted cashflow analysis were taken from the U.S. Environmental Protection Agency's (EPA's) LFG Energy Cost Model (U.S. Environmental Protection Agency, 2022). We also incorporated IPCC estimates for planning and design overhead costs (IEA-ETSAP, 2013) and data on pipeline injection fees from Verbeeck et al. (2018) (see Table 1).

Table 1. Landfill gas upgrading costs, adapted from EPA's LFG Energy Cost Model.

	Flow rate (m^3/hr)	CAPEX (2021 €)	Annual OPEX (2021 €)	Minimum selling price (€/GJ)
Small facility	500	7,661,700	227,500	19.34
Large facility	1,000	8,200,500	269,900	10.53

Total LFG project costs scale proportionally with daily flow rates. It is difficult to determine the average size of landfill gas projects throughout the EU, so we divided the cost estimates into small and large facilities, defined as 500 cubic meters per hour (m^3/hr) and 1,000 m^3/hr flow rates, respectively. Flow rates are based on project data reported for 10 LFG grid-injection facilities in France (Waga Energy, 2021) and midsize project estimates in the United States (U.S. Environmental Protection Agency, 2021). We compare country-level MSW landfilling rates and total volumes treated to estimate the share of small and large landfills in the EU. For countries with greater than 50% MSW landfilling rates, we assumed that LFG facilities fall within the large flow rate range; we assumed the remainder of LFG projects have small flow rates. We calculated the aggregate volume of MSW that falls within each flow rate range based on waste disposal tonnage data (Eurostat, 2021b). In the absence of more granular data, we assumed that half of LFG facilities are large facilities, and the remaining half are small. The minimum selling prices for these renewable LNG pathways are the lowest of all conversion pathways. We estimated the minimum selling prices to be €10.5 or €19.3/GJ for large or small LFG facilities, respectively.

Biomethane derived from agricultural digesters has the highest levelized production cost of all pathways. Manure facilities are separated into three categories (large dairy, small dairy, and nondairy) based on facility size, livestock composition, and methane-generating potential (Baldino et al., 2018). The minimum selling price is averaged across EU member states for each manure biomethane category; costs scale with the size and methane-generating potential of each facility. Nondairy farms make up the largest share of farms in the European Union. The estimated cost of bio-LNG production from these facilities is €216/GJ, almost 30 times higher than the cost of fossil LNG.

e-LNG is produced by combining hydrogen derived from water electrolysis with CO_2 using a methanation reaction. Thus, the main components of e-LNG cost modeling include capital investment in electrolyzer and methanation equipment and the feedstock cost of electricity and CO_2. We assumed in this analysis that renewable electricity is used as the power input. The source of CO_2 is assumed to be a point source, which we assume will cost $40/t, as shown in Table 2. This is an important assumption because the cost of e-LNG is sensitive to the cost of the carbon source. Point sources of CO_2 such as fossil fuel power plants and bioenergy plants exist today and could be used as a near-term source of CO_2. However, as efforts to decarbonize major industrial sectors ramp up, it is likely that fewer fossil point sources will remain in the future; additionally, there are concerns about relying on fossil-derived CO_2 if it prolongs the use of fossil fuels. The alternative is to use direct air capture (DAC), which temporarily removes CO_2 from the atmosphere and re-releases it once the fuel is burned. However, DAC is likely to be several times more expensive than point source capture, particularly in the near-term. Estimates for DAC, the technology for which is not yet mature, range from $100 to $700/t (Becattini et al., 2021; Keith et al., 2018). Taking a midrange estimate of $240 per tonne of DAC carbon capture from the IEA (2020), the DAC-derived e-methane fuel would be approximately 30% more expensive than point source-derived e-methane; however, given the range of estimates for DAC and that it has not yet scaled, any estimates of DAC-derived e-LNG are uncertain. Additionally, it is debatable whether DAC could be deployed at a reasonable-enough price and sufficient scale by 2030 to satisfy demand for e-LNG. We therefore modeled an assumed price of carbon capture at $40/t, recognizing that it implies at least temporary use of captured fossil CO_2. Policies to ensure that this is indeed only temporary and to accelerate the rollout of DAC might be needed if use of DAC for e-fuels is cost-prohibitive.

We used a discounted cash flow model similar to the bio-LNG pathways to estimate the levelized production cost of e-LNG in Europe, following the methodology in Christensen and Petrenko (2017). While e-methane production plants could be connected to the electricity grid or connected directly to a renewable electricity generator, Christensen and Petrenko estimated that grid-connected plants tend to have lower e-methane production costs than plants that are directly connected. This is because direct connection often results in a lower capacity factor, which defines how often a plant can run, compared to grid connection. To err on the side of lower e-LNG costs, which would make e-LNG more cost competitive with fossil LNG, we assumed that e-LNG is produced using 100% renewable electricity supplied through the grid with a capacity factor of 95%. This implies the use of renewable electricity supplied through a power purchase agreement wherein the e-methane producer funds the renewable electricity supplier, even though the electricity production might not match up temporally for the e-methane use.

Table 2 lists the key variables and assumptions used in the e-LNG cost model. Methanation capital cost is subject to economies of scale and thus impacted by plant capacity (Brynolf et al., 2018). We assumed an e-methane production plant with an annual capacity of about 200 MW_{fuel}, which is a midsize plant. We applied methanation capital cost and conversion efficiency from Brynolf et al. and converted to Euros by assuming a conversion rate of €0.8458 per US$1.[3]

Table 2. Assumptions of e-methane plant design and costs.

Input variable	Data assumption	Source
Plant capacity	200 MW_{fuel}	Brynolf et al. (2018)
Methanation capital cost	220 $/$kW_{fuel}$	Brynolf et al. (2018)
Electrolyzer capital cost	988–1346 $/$kW_{input\ power}$ depending on electrolyzer type	Christensen (2020)
Electrolyzer capital cost reduction in the future	2% annually	Christensen (2020)
Electrolyzer efficiency	60% to 81%, depending on electrolyzer type	Christensen (2020)
Electrolyzer efficiency improvement in the future	0.4%–0.8% annually depending on electrolyzer type	Christensen (2020)
Fixed annual operational cost	4% of total capital cost	Christensen (2020)
CO_2 price	$40/tonne	Christensen and Petrenko (2017), Terwel and Kerkhoven (2018)

For the underlying renewable electricity price to produce e-methane, we develop our own model for the European Union based on the methodology in Christensen

3 This is the average conversion rate in 2021, as found at https://www.exchangerates.org.uk/USD-EUR-spot-exchange-rates-history-2021.html

(2020). Specifically, we updated that analysis to include projections of capital costs and operational expenses of solar and wind power plants from the National Renewable Energy Laboratory (National Renewable Energy Laboratory, 2021). Although this dataset is based on the U.S. market, we assumed similar costs for the EU. We adjust to account for solar and wind capacity factors in the EU from the Joint Research Centre (2018). For future renewable electricity prices, we adjusted per-kWh costs to account for the capital cost reduction rate and technology improvement rate from NREL. We also included relevant grid fees and taxes, which were calculated by Searle and Christensen (2018), in addition to the estimated levelized renewable electricity price. We present the estimated 2030 renewable electricity price, including grid fees and taxes, and the calculated baseline e-methane and final e-LNG prices, including the cost of liquefaction, in Table 3. We include 2020 to show how we expect the prices to change by 2030.

Table 3. Estimated prices relevant to e-LNG ship fuel in the European Union.

Year	Renewable electricity price (€/MWh)	Renewable electricity price (€/GJ)	e-methane price (€/GJ)	e-LNG price (€/GJ)
2020	117	27.30	62.98	64.93
2030	97	22.63	47.52	49.48

ESTIMATING WELL-TO-WAKE CO_2-EQUIVALENT EMISSIONS

For fossil LNG, we used WTW emission factors from Comer and Osipova (2021), as shown in Table 4. These account for upstream and downstream CO_2, methane (CH_4), nitrous oxide (N_2O), and black carbon (BC) and these are converted to CO_2e emissions using GWPs for GHGs from the IPCC's Sixth Assessment report (IPCC, 2021) and GWPs from Bond et al. (2013) and Comer et al. (2017) for BC, as found in Table 5. The upstream well-to-tank emission factors are from GREET (Wang et al., 2021), and the downstream tank-to-wake values are derived using emission factors (g pollutant/kWh) and specific fuel consumption (g fuel/kWh) from the Fourth IMO Greenhouse Gas Study. Comer and Osipova (2021) also include crankcase methane emissions based on Pavlenko et al. (2020), which estimated that LPDF engines emit an additional 1 gCH_4/kWh if the engine has an open crankcase. However, the proportion of engines with open crankcases is not well known and so we exclude crankcase emissions from this analysis. See Comer and Osipova (2021) for a detailed description of the methodology.

Table 4. Well-to-wake fossil LNG CO_2e emissions of different LNG engine types.

Engine type	CO_2e100	CO_2e20
LPDF, 4-stroke	4.930	7.801
LPDF, 2-stroke	4.385	6.288
HPDF	3.940	5.008
LBSI	4.663	7.060
Steam turbine	3.859	4.856

Source: Comer and Osipova (2021)

Table 5. Overview of global warming potentials used in this analysis.

Pollutant	GWP100	GWP20	Source
CO_2	1	1	Reference level
Methane (fossil origin)	29.8	82.5	IPCC AR6 Table 7.15
Methane (bio origin)	27.2	80.8	IPCC AR6 Table 7.15
N_2O	273	273	IPCC AR6 Table 7.15
BC	900	3200	Bond et al. (2013) and Comer et al. (2017)

BioLNG and e-LNG fuels might have substantially different climate implications depending on the feedstock or energy source from which they are made and how they are produced (which is to say, their conversion pathway). Generally, bio-LNG pathways made from captured methane that would have been emitted in the absence of biofuel production, such as wastes or residues, have negative GHG emissions based on crediting of avoided methane emissions. The emissions for producing e-LNG made from electricity and captured CO_2, meanwhile, vary significantly based on the carbon intensity of the electricity and the method of CO_2 capture (Reiter & Lindorfer, 2015). Here we summarize the possible range of emissions attributable to bioLNG and e-LNG.

For well-to-tank emissions, we begin with upstream biomethane and e-methane GHG emissions from Zhou et al. (2021), which modified GREET to incorporate several EU-specific assumptions. For biomethane, Zhou et al. conducted a sensitivity analysis of production assumptions for each fuel. The authors assessed key parameters for landfill, wastewater, and manure-derived biogas, including yield, methane capture rate, and methane leakage rate during upgrading, with the range of values informed by a literature review. Zhou et al. found that small differences in methane leakage impact the final LCA estimate. For e-methane, we assumed the best-case scenario: that it is produced from renewable electricity and CO_2 from point source capture powered by renewable electricity. We assumed e-methane production emissions are consistent with the e-fuel pathway for liquid fuels in GREET and a carbon intensity of 4.1 gCO_2e/MJ (Wang et al., 2021). This assumes a configuration using renewable electricity to supply hydrogen via electrolysis, in conjunction with low temperature DAC using renewable electricity and waste heat.

Because methane needs to be liquefied for use as a marine fuel, we added emissions associated with liquefaction, distribution, and storage, as shown in Figure 6. Liquefaction emissions for each pathway were taken from GREET (Wang et al., 2021). For biomethane from manure, landfill gas, and wastewater sludge, we assumed onsite liquefaction, adding from 2.4 to 7.1 gCO_2e/MJ, depending on the pathway in GREET. For methane produced from gasification and e-LNG, we assumed that they are liquefied consistent with the pathway for natural gas used as a transportation fuel in GREET, with a liquefaction emissions intensity of 1.1 gCO_2e/MJ and assuming the use of renewable or e-methane as a process fuel. We also included downstream transport and storage emissions, which include boil-off and leakage for distribution and which contribute 0.6 gCO_2e and 2.5 gCO_2e/MJ, respectively, depending on the pathway.

Lastly, we accounted for downstream tank-to-wake emissions. The tank-to-wake CO_2 emissions from combusting the fuels are offset by the CO_2 sequestered by the biomass feedstock in the case of biomethane or by upstream CO_2 capture in the case of e-methane. However, any methane that is not converted to CO_2 and escapes unburned from the engine (methane slip) reduces the potential climate benefits of bioLNG and e-LNG and needs to be accounted for. To do this, we used methane slip emission factors from the *Fourth IMO Greenhouse Gas Study* (Faber et al., 2020), as shown in Table 6. We added to this CO_2, N_2O, and BC emission factors from Comer and Osipova (2021), which are consistent with those of Faber et al. (2020).

Table 6. Methane slip assumptions.

Engine type	Methane slip (% of fuel consumption)
LPDF, 4-stroke	3.53%
LPDF, 2-stroke	1.69%
HPDF	0.15%
LBSI	2.63%
Steam turbine	0.01%

Source: Faber et al. (2020)

Figure 6 illustrates the potential emissions from methane slip relative to the upstream emissions for gas production, liquefaction, and distribution of e-methane. From left to right, the chart illustrates that each subsequent stage of the supply chain can add to the emissions attributable to e-methane. Though e-methane itself is a low-carbon fuel with production emissions of 4.1 gCO_2e/MJ, its emissions from liquefaction and distribution increase its impact to approximately 7.6 gCO_2e/MJ, and onboard methane slip could increase its impact further to approximately 27.7 gCO_2e100/MJ or 71.9 gCO_2e20/MJ, depending on the type of engine it is used in.[4] This highlights how methane leaks can have profound climate impacts, even in the case of renewably derived e-LNG.

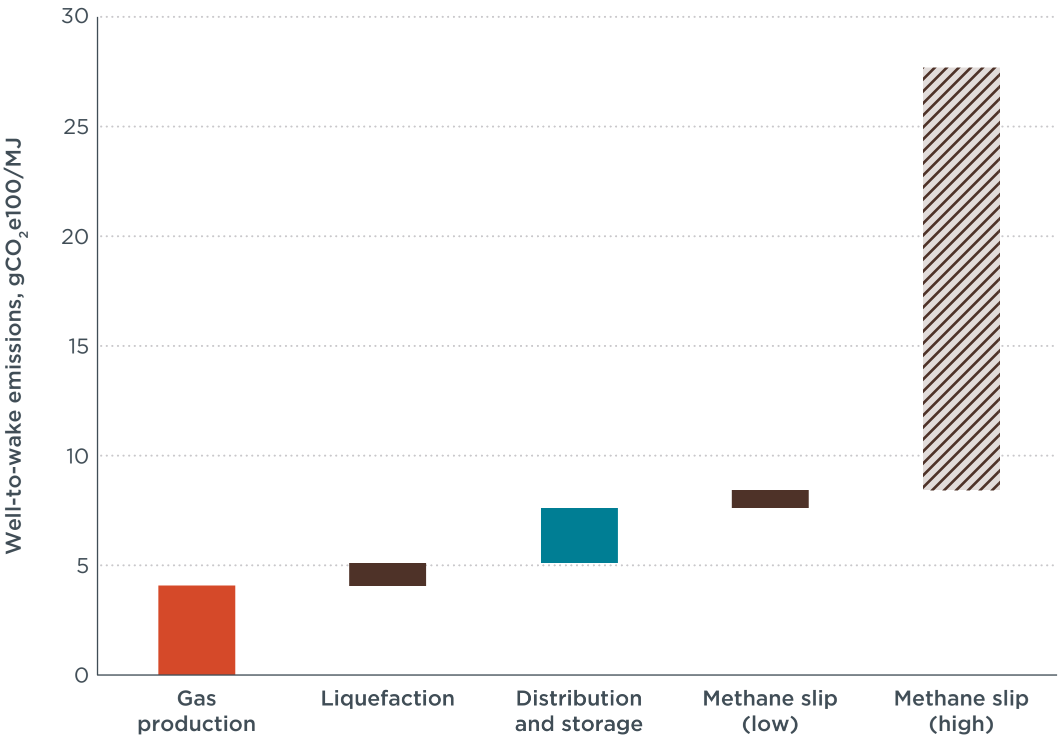


Figure 6. Estimated well-to-wake emissions from e-LNG using GWP100 and separated by stage.

Thus, the choice of engine makes a substantial impact on the emissions impacts for a given renewable LNG application. Figure 7 shows the WTW emissions for the six sources of renewable LNG analyzed in this study. The error bars show the range of total WTW emissions due to variations in upstream methane leakage and variations in methane slip. For each renewable LNG pathway, the upper bound of emissions increases substantially when it is used in engines with high methane slip.

4 CO_2e100 and CO_2e20 refer to carbon dioxide equivalent emissions based on their 100-year and 20-year global warming potential.

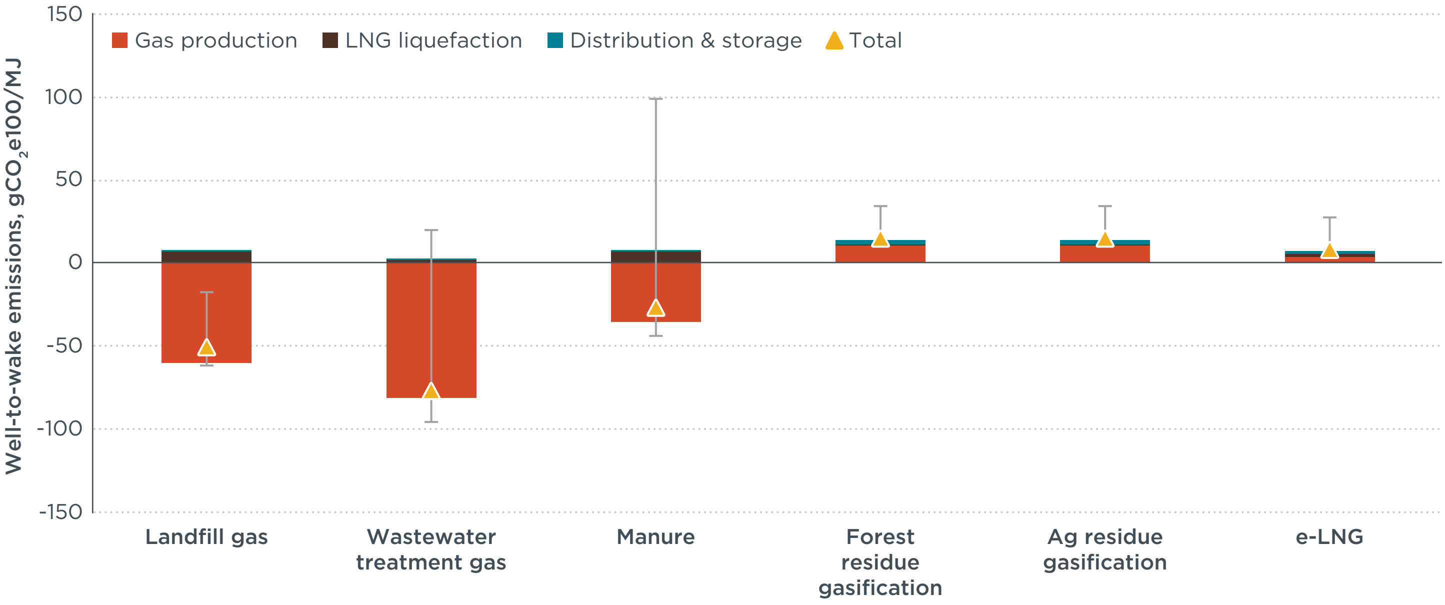


Figure 7. Well-to-wake emissions for renewable LNG combusted on ships using GWP100, with error bars illustrating the potential emissions range when factoring in methane leakage and onboard methane slip.

RESULTS

LNG DEMAND IN 2019 AND 2030

As shown in Figure 8, we predict that by 2030 global LNG demand will increase to 36.2 Mt or 1,738 PJ, about three times higher than in 2019. Assuming the EU will continue to account for the same share of global demand as it did in 2019 (20.5%), we expect ships on voyages to, from, and between EU ports to demand 7.42 Mt of LNG, or 356 PJ, in 2030.

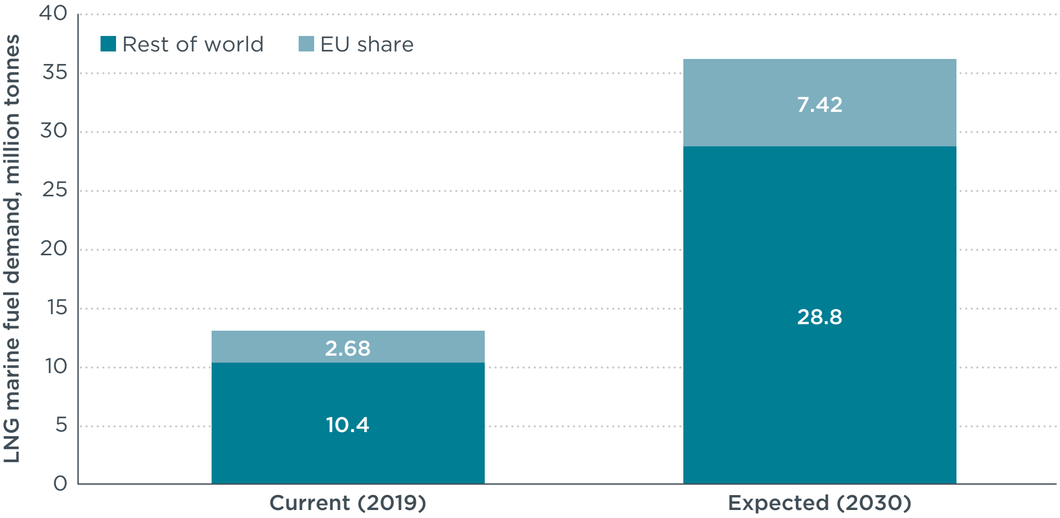


Figure 8. Estimated demand for marine LNG fuel in 2019 and 2030.

TOTAL WELL-TO-WAKE CO_2-EQUIVALENT EMISSIONS FROM FOSSIL LNG IN 2019 AND 2030

Figure 9 shows the WTW CO_2e emissions that would result from satisfying 2019 and 2030 LNG demand for ships on voyages to, from, and between EU ports using fossil LNG. It illustrates WTW CO_2e emissions based on both GWP100 and GWP20 and is based on the proportion of LNG consumed by each engine type, per Figure 5. The red bar shows the CO_2e from WTW methane emissions. Black carbon and N_2O emissions are low and do not meaningfully contribute to the WTW emissions of LNG. If 2030 LNG demand grows as we project, and is satisfied by 100% fossil sources, WTW CO_2e emissions from LNG-fueled ships would more than triple between 2019 and 2030.

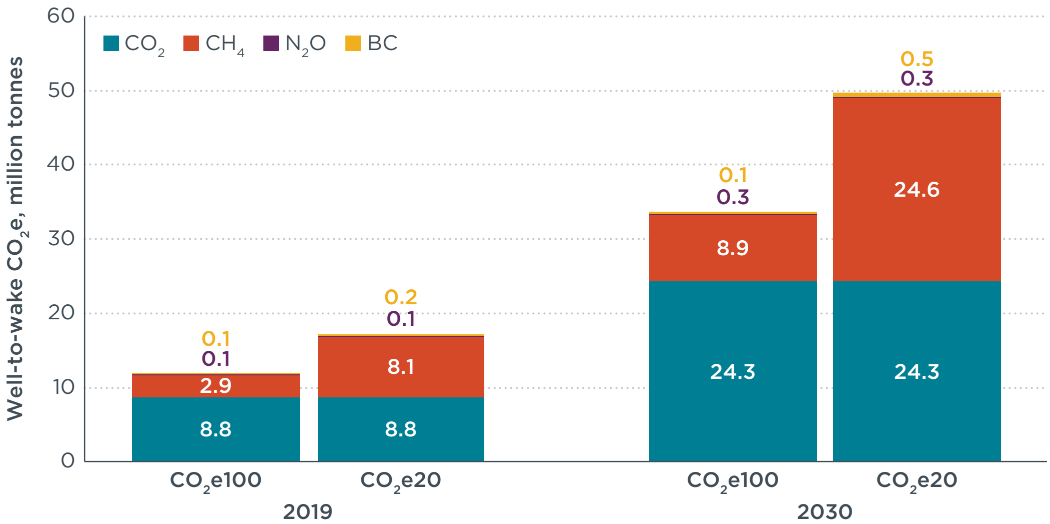


Figure 9. Well-to-wake CO_2e emissions for LNG-fueled ships on voyages to, from, and between EU ports in 2019 and predicted for 2030, assuming those ships use 100% fossil LNG.

FUTURE RENEWABLE METHANE SUPPLY

As shown in Figure 10, we estimate that a maximum of 700 PJ of bioLNG could be available in 2030 if shipowners, operators, and charterers are willing to pay up to €216/GJ (equivalent to more than €10,000/t) for some of it. That price, which is for bioLNG from nondairy manure, is nearly 30 times higher than the expected price of fossil LNG in 2030.

The majority of available biomethane is from gasification of agricultural residues and manure digestion from nondairy farms. The remaining pathways make up only 8% of EU biomethane supply. Landfill gas availability is expected to be low because of its current use for on-site electricity generation.

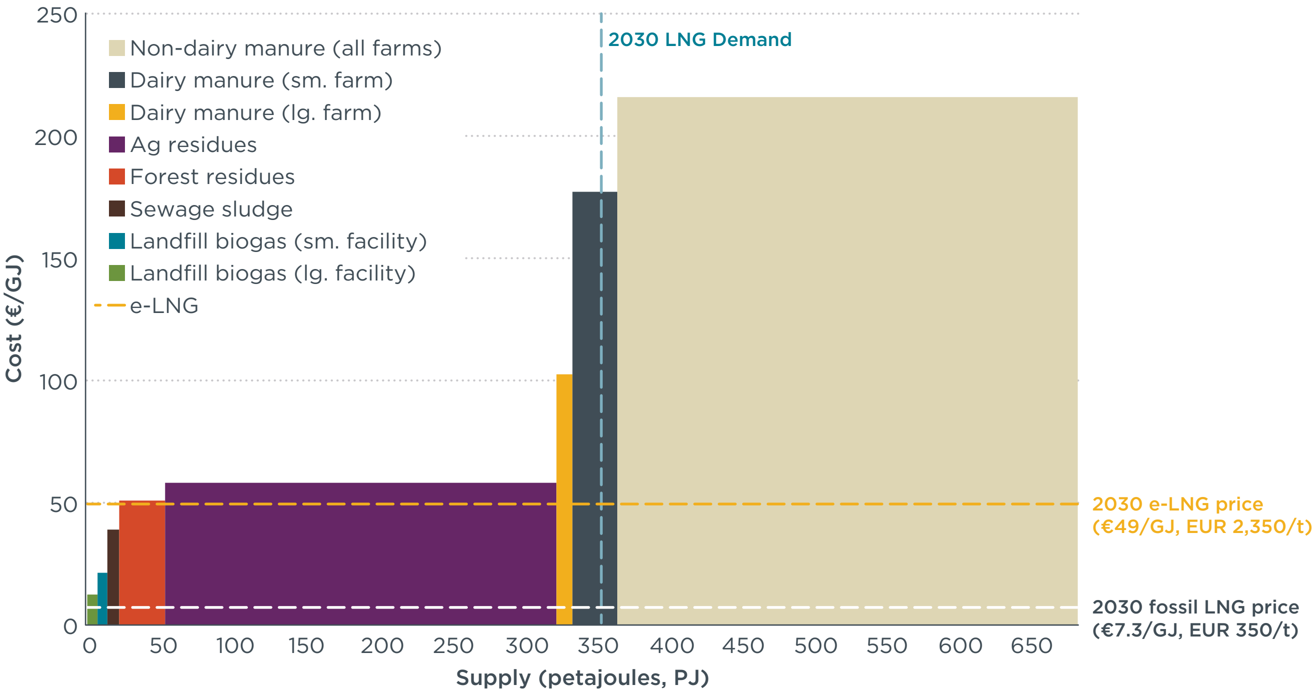


Figure 10. Estimated 2030 supply curve for bioLNG by production pathway, plus estimated 2030 prices for fossil and e-LNG (horizontal lines), compared to estimated 2030 LNG marine fuel demand for ships trading with the European Union (vertical line).

It is possible to supplement the bioLNG supply with e-LNG, but as Figure 10 also shows, that comes at a price. We estimate that e-LNG could be supplied at approximately €49/GJ (€2,350/t), which is almost seven times higher than the expected 2030 fossil LNG price of €7.3/GJ (€350/t). Note that this assumes point source carbon capture at $40/t (€34/t) of CO_2, not DAC. Previously, we estimated that if DAC for e-LNG production costs $240/t (€203/t), it would increase the cost of e-LNG by approximately 30%; however, the price of DAC-derived e-LNG remains uncertain, as the range of DAC cost estimates range from $100/t (€85/t) to $700/t (€592) and its contribution to e-LNG production costs could vary considerably.

If the EU were willing to offer a €25/GJ (€1,200/t) subsidy to purchase renewable LNG, which is the current mid-range level of EU policy support for grid-injected biomethane, we estimate that only 15 PJ, or 4%, of 2030 LNG demand could be met with renewable LNG. All of it would be bioLNG because e-LNG costs €49/GJ, which would require at least a €42/GJ subsidy to make it economical, given the €7.3/GJ fossil LNG price. Alternatively, if the EU were willing to double the subsidy to €50/GJ (€2,400 t), higher than any current policy incentive in Europe, roughly 90% of 2030 demand could be met with available biomass feedstocks; this is because this level of policy support would unlock supply of bioLNG made from agricultural residues, shown as the large purple block in Figure 10. However, at that level of subsidy, e-LNG, which we expect to cost €49/GJ, would also become available. Therefore, with a €50/GJ subsidy, we expect that renewable LNG would be a mix of bio and synthetic sources. These are shown in Figure 11.

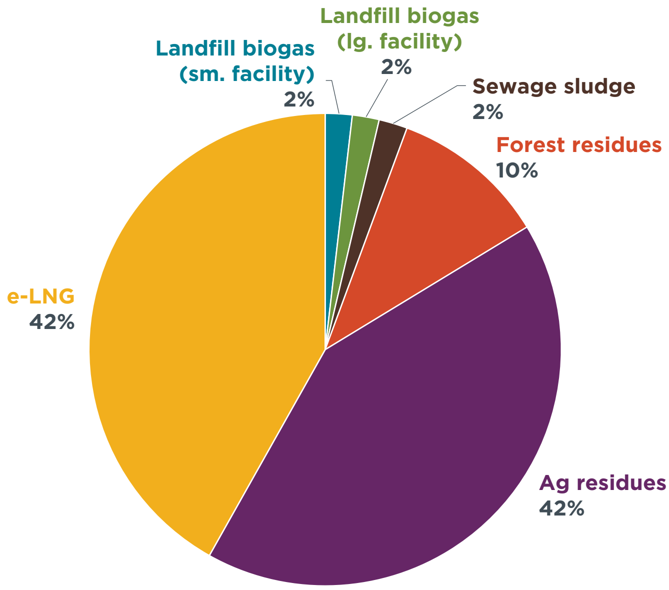


Figure 11. Projected mix of renewable LNG feedstocks to supply 2030 EU marine LNG demand under a €50/GJ subsidy scenario.

WELL-TO-WAKE EMISSIONS UNDER THREE 2030 LNG SCENARIOS

Based on the projected 2030 EU LNG demand of 356 PJ and the cost curve of renewable LNG supply in 2030 in Figure 10, we project the mix of renewable LNG that could feasibly meet LNG demand for ships on voyages to, from, and between EU ports under three EU subsidy scenarios: (a) no subsidy, (b) €25/GJ subsidy, and (c) €50/GJ subsidy. We then calculate the well-to-wake CO_2e emissions associated with each scenario.

For the no-subsidy scenario, 100% of 2030 LNG demand is met by fossil LNG. For the €25/GJ scenario, 96% of 2030 LNG demand is met by fossil LNG and 4% by bio sources, which are made from landfill gas. At €50/GJ, the LNG fuel mix is expected to be broader. Because a €50/GJ subsidy would be in addition to a €7.3/GJ fossil LNG price, it would enable the use of fuels that cost up to €57.3/GJ (€2,750/t LNG). This unlocks the potential to use bioLNG made from agricultural residues, as well as e-LNG made from renewable electricity and point source captured carbon dioxide. Agricultural residues could theoretically supply about 270 PJ, or 75% of the 356 PJ of LNG demanded in 2030, but fuel purchasers are expected to be indifferent to the source of renewable LNG at a given price. We therefore start by using the full supply of landfill gas, sewage sludge, and forest residues and split the remaining supply between agricultural residues and e-LNG, as shown in Figure 11. The weighted average cost of supplying this fuel mix is approximately €51/GJ. Using GWP100 and before accounting for methane slip from the engine, this fuel mix has a well-to-tank GHG intensity of 7.1 gCO_2e100/MJ (11.6 gCO_2e20/MJ), including upstream methane leakage.

The WTW CO_2e emissions associated with the three subsidy scenarios shown in Figure 12 are each presented in terms of GWP100 and GWP20 and broken out by pollutant. The resultant GHG emissions intensity for each scenario is presented in Table 7.

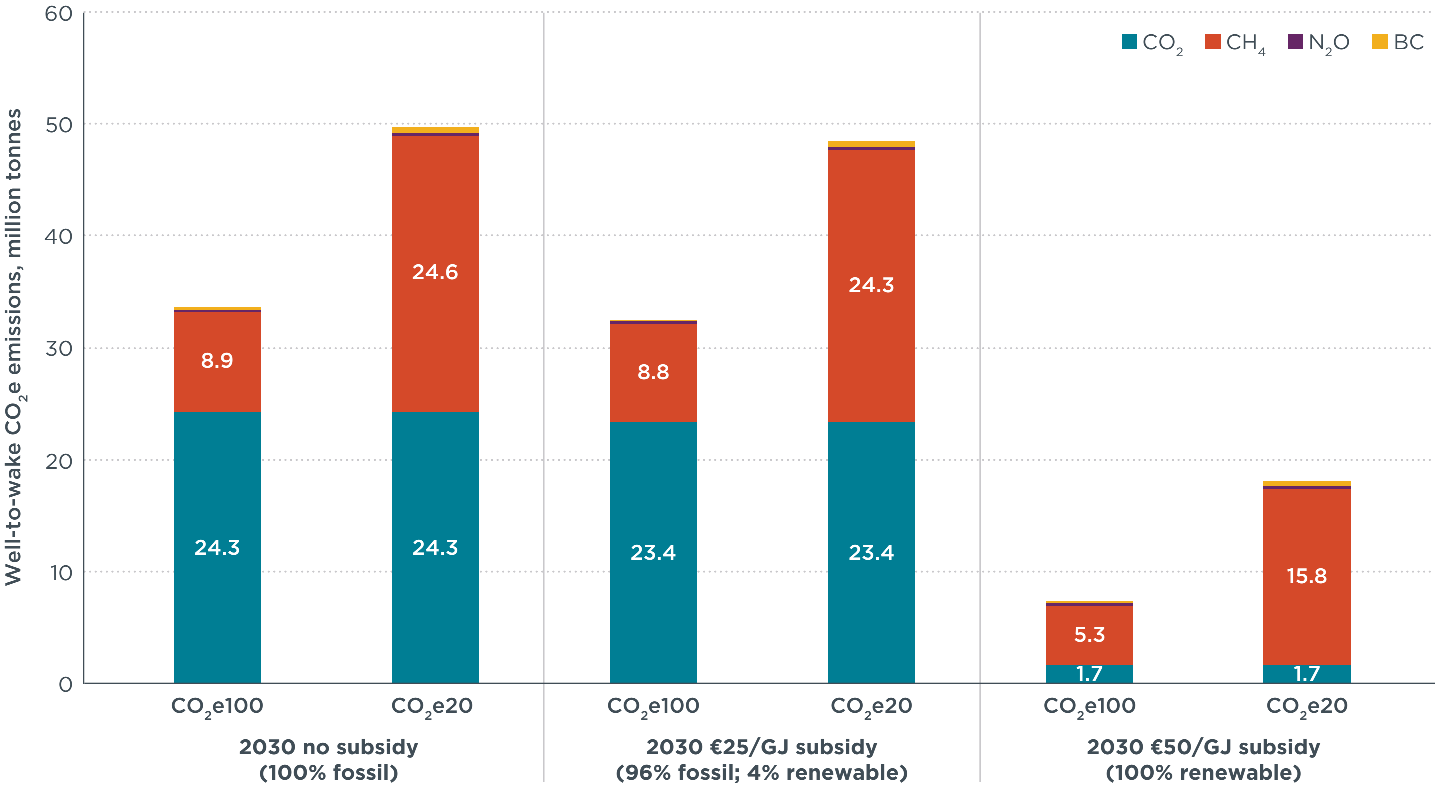


Figure 12. Estimated well-to-wake CO_2e emissions from LNG-fueled ships trading with the European Union under three 2030 subsidy scenarios.

Table 7. Well-to-wake carbon dioxide equivalent intensity for three subsidy scenarios.

Scenario	CO_2e100/MJ	CO_2e20/MJ
No subsidy	94.5	139.7
€25/GJ	91.5	136.2
€50/GJ	20.6	50.7

A subsidy of €25/GJ would reduce WTW CO_2e emissions by only 3.2% (GWP100) or 2.5% (GWP20) because only the least-expensive bio-LNG pathways are made cost-competitive with fossil LNG.

A subsidy of €50/GJ enables a full transition to renewable LNG and would reduce 2030 WTW CO_2e emissions by 79% on a GWP100 basis, and 65% on a GWP20 basis compared to the "no subsidy" scenario. However, this would require total annual public expenditures of €17.8 billion, and even in this scenario, WTW CO_2e emissions from LNG-fueled ships are approximately 38% below 2019 levels if calculated based on GWP100, but 6% higher than 2019 if calculated based on GWP20. This is because of the large contribution of methane leakage and slip to the overall WTW CO_2e emissions, which account for 87% of CO_2e20 emissions in 2030 (Figure 12) compared to about 47% of CO_2e20 emissions in 2019 (Figure 9). In 2030, the WTW CO_2 emissions are low in this scenario because combustion CO_2 emissions are offset by negative upstream CO_2 emissions, whereas in 2019, the CO_2 portion of CO_2e is of fossil origin. Because biogenic methane's GWP20 is about three-times higher than its GWP100, methane emissions contribute strongly to CO_2e20 values.

Under all scenarios, absolute methane emissions are projected to increase relative to 2019 levels. This is due in part to a nearly three-fold increase in demand for LNG between 2019 and 2030. Additionally, in 2019, half of the WTW methane emissions were from upstream methane leakage and half were from downstream methane slip.

However, by 2030 the share of downstream methane slip increases relative to total methane emissions as the share of LNG burned in LPDF 4-stroke engines and LBSI engines increases, and the share of LNG burned in steam turbines and HPDF engines decreases relative to 2019. By 2030, we expect WTW methane emissions to triple from 2019 levels, even if a €25/GJ (€1,200/t LNG) subsidy, equivalent to €8.9 billion per year, is offered. Additionally, even if a €50/GJ (€2,400/t LNG) subsidy were to be offered in 2030, which would require €17.8 billion per year of public investment, we expect WTW methane emissions to double from 2019 levels, primarily because of methane slip.

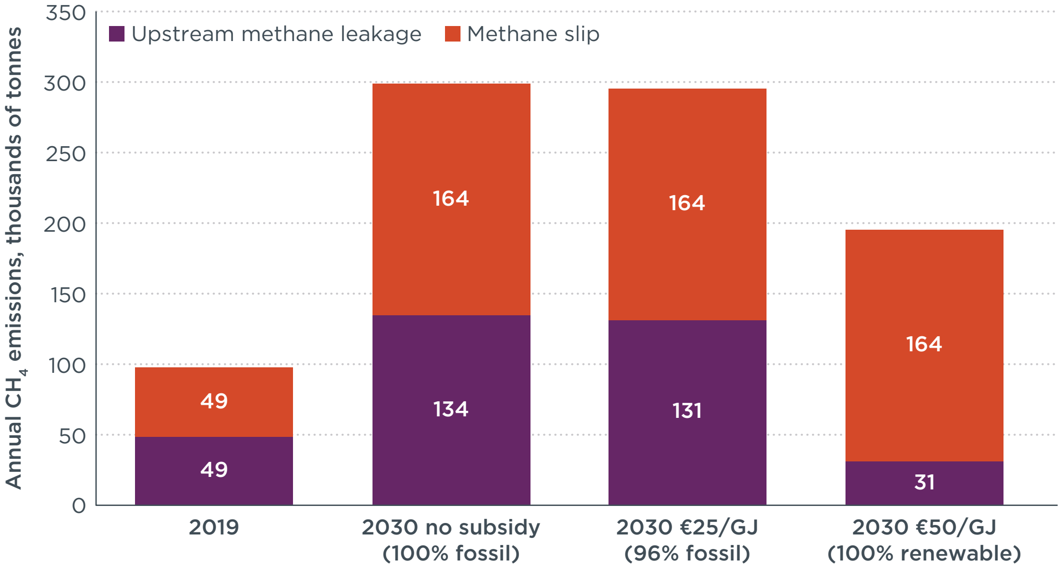


Figure 13. Estimated methane emissions from LNG-fueled ships trading with the European Union in 2019 and in three 2030 subsidy scenarios.

POLICY IMPLICATIONS

The European Climate Law requires reducing economy-wide GHG emissions by at least 55% below 1990 levels by 2030, and that would require a 41% reduction in GHG emissions from the 2019 level. Additionally, the European Union, together with the United States, launched the Global Methane Pledge at COP26, and more than 100 countries have signed on. While there are no individual obligations by country or region, this pledge aims to cut global methane emissions by at least 30% from 2020 levels by 2030.

Based on the preceding analysis, demand for LNG could nearly triple between 2019 and 2030 for ships on voyages to, from, and between EU ports. If all of this demand is met by fossil LNG, WTW CO_2e emissions, including WTW methane emissions, from LNG-fueled ships are expected to nearly triple as well. But policy will have an impact on the GHG emissions from LNG-fueled ships, and in the EU, the market will be affected by subsidy structures, the EU Emission Trading System (EU ETS), and the new FuelEU Maritime regulation.

SUBSIDIES

Historically, LNG prices have averaged €7.3/GJ. We found that a subsidy of €50/GJ, or seven times the historical fossil LNG price, would be needed to unlock enough supply of renewable LNG to satisfy 2030 demand. At this level of subsidy, there is enough potential supply of bioLNG, and e-LNG using point source carbon capture becomes available. However, such a subsidy would require annual public expenditures of €17.8 billion in 2030. The €50/GJ subsidy scenario would reduce 2030 WTW CO_2e emissions from LNG-fueled ships by 79% on a GWP100 basis and 65% on a GWP20 basis compared to a no-subsidy scenario.

However, would attaining a 100% renewable supply of LNG for ships help achieve the EU's 2030 goal of reducing GHG's 55% below 1990 levels by 2030 (equivalent to 41% below 2019)? Using 100% renewable LNG would reduce WTW CO_2e100 emissions from LNG-fueled ships by 38% from 2019 levels by 2030, as shown in Figure 14. However, if evaluated using 20-year GWPs, the WTW CO_2e20 emissions actually increase 6% from 2019 levels by 2030. This is because of the large amount of methane emissions, mostly in the form of methane slip from marine engines, that account for nearly 90% of CO_2e20 emissions in 2030 compared to about half in 2019. Because methane has a GWP20 of more than 80 compared to 1 for CO_2, the larger share of methane compared to CO_2 results in large CO_2e emissions on a 20-year time scale.

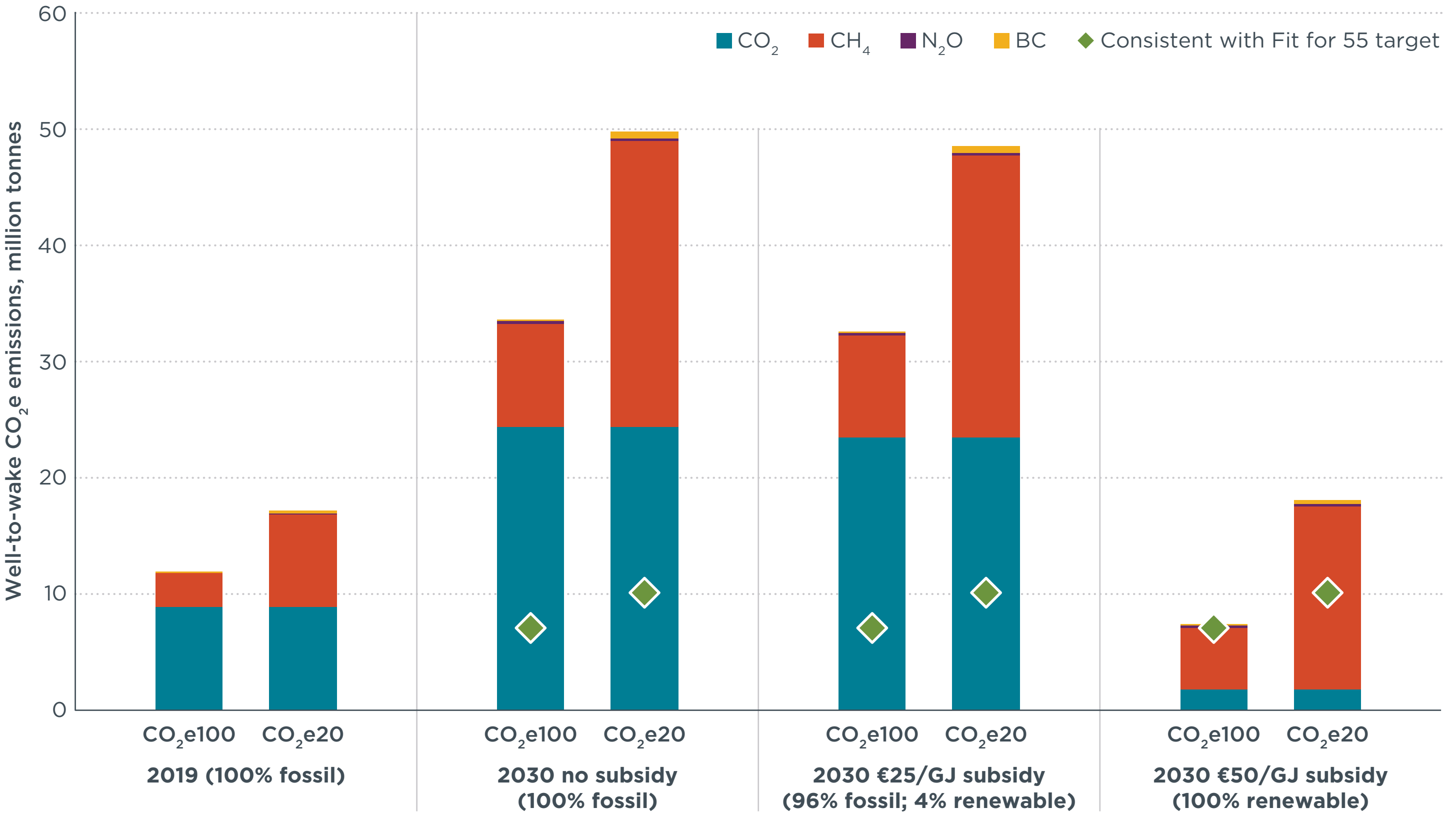


Figure 14. Comparing the Fit for 55 target, as applied to LNG-fueled ships trading with the European Union, with well-to-wake emissions under three 2030 subsidy scenarios.

Now let us consider methane emissions alone. For the sake of discussion, assume that 2020 methane emissions were the same as 2019. In the no subsidy and €25/GJ subsidy scenarios, methane emissions triple from 2019 to 2030 (see Figure 15). In these scenarios, even if methane slip could be eliminated, the upstream methane emissions alone would mean that using LNG would lead to an increase in methane emissions. Even with 100% renewable LNG, as is the case in the €50/GJ scenario, total WTW methane emissions double between 2019 and 2030. In this scenario, methane emissions from methane slip total 164 kt and upstream emissions account for 31 kt.

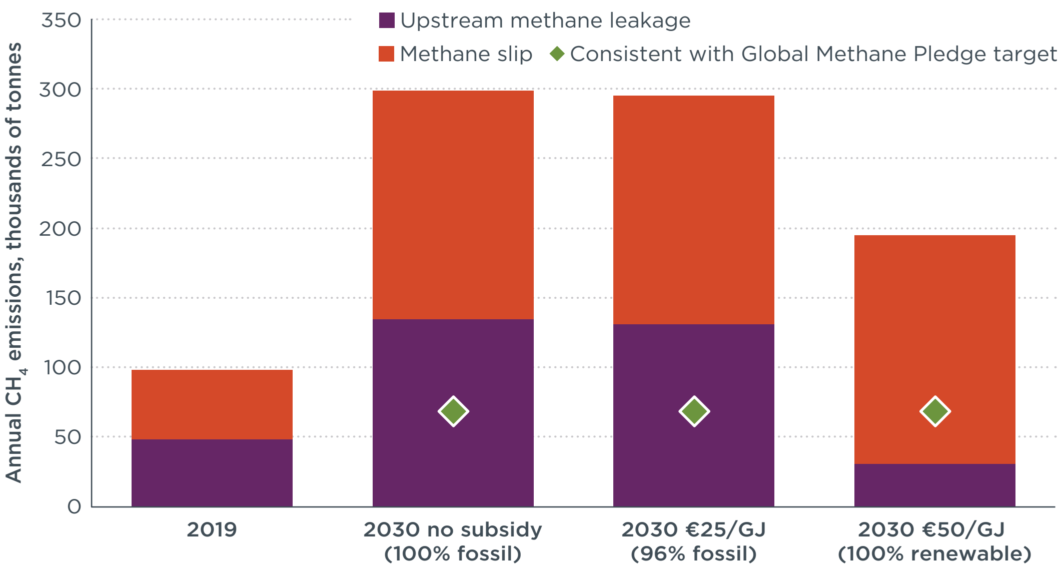


Figure 15. Comparing the Global Methane Pledge target, as applied to LNG-fueled ships trading with the European Union, to well-to-wake methane emissions under three 2030 subsidy scenarios.

To be consistent with the magnitude of global methane reductions called for under the Global Methane Pledge, WTW 2030 methane emissions from LNG-fueled ships sailing in the EU would need to be below approximately 70 kt. The only way using renewable LNG could be compatible would be to reduce total 2030 methane emissions by at least 65%, which would result in 68 kt of methane emissions. If we hold upstream methane leakages constant, methane slip would need to be reduced at least 77%. This could be achieved if all LNG-fueled ships used the best-in-class engine technology, HPDF. Using only HPDF engines would result in just 11 kt of methane slip emissions in 2030, bringing total 2030 methane emissions to 42 kt. However, as previously discussed, HPDF engines accounted for 11% of LNG consumption in 2019 and we expect their share to drop to 7% by 2030 as a greater proportion of ships use LPDF, 4-stroke engines. HPDF technology is mainly used on 2-stroke engines, whereas most LNG fuel consumption today occurs in 4-stroke engines. We do not believe it is realistic to think that the existing fleet could or would be modified to achieve the same low methane slip emissions as HPDF engines by 2030. If, instead, we maintain the projected 2030 engine mix and assume that methane slip from LPDF and LBSI engines could be cut in half, total methane emissions would be approximately 114 kt, which is still higher than 2019.

EU ETS

To support the use of renewable LNG, the EU ETS price needs to be high enough to make fossil LNG cost as much or more than renewable LNG. In the first quarter of 2022, the EU ETS price was approaching €100/t CO_2 (EEX EUA, 2022). Note that because the ETS charges based on CO_2 and not CO_2e, the methane emissions from LNG are not penalized and LNG has an advantage over other marine fuels (for example, HFO, MGO, and very low sulfur fuel oil [VLSFO]) because it emits less CO_2 per unit of energy produced by the engine. Fossil LNG emits 2.75 tonnes of CO_2 per tonne of LNG. At current EU ETS prices, each tonne of LNG results in a fee of €275. Previously, we noted that a subsidy of €50/GJ is required to unlock a 100% renewable LNG supply for shipping. This is equivalent to €2,400/t fuel. Therefore, the EU ETS price would need to grow to approximately €875/t CO_2 to incentivize a shift from fossil LNG to renewable LNG, nearly nine times higher than its current price. Additionally, methane emissions would still be expected to be twice as high as 2019 levels in 2030, even under a 100% renewable LNG scenario. Either a separate policy would be needed to regulate methane emissions or CO_2e emissions, or the EU ETS price could be increased or amended to charge based on CO_2e.

FuelEU MARITIME

By 2030, the FuelEU Maritime initiative requires the GHG intensity of the fuel used by the fleet to be 6% lower than the 2020 baseline. Transport & Environment (2022) estimated the 2020 baseline to be approximately 91.7 gCO_2e100/MJ, meaning the 2030 limit would be 86.2 gCO_2e100/MJ. To assess the carbon intensity of LNG-fueled engines, the FuelEU Maritime initiative applies assumptions for the amount of methane slip depending on the engine in which the fuel is consumed. As shown in Figure 16, using assumptions consistent with FuelEU Maritime (see Table 8), we estimate that the best-performing internal combustion engine, HPDF, emits 76.4 gCO_2e100/MJ (11% below baseline) and steam turbines emit approximately 75.3 gCO_2e100/MJ (12.6% below baseline).[5] Steam turbines are much less efficient than internal combustion engines, meaning they consume more fuel to produce the same amount energy out of the engine, but they have very low methane slip. The thermal efficiency of a steam turbine is approximately 28%, whereas marine internal combustion engines exceed 50% (Pavlenko et al., 2020).

5 As shown in Table 4, the HPDF engine emits WTW emissions of 3.940 gCO_2e100/g fuel. Assuming 48 MJ/kg (0.048 MJ/g) for LNG, that works out to 82.1 gCO_2e100/MJ as follows: 3.940 / 0.048 = 82.1. Similarly, steam turbines emit 3.859 gCO_2e100/g fuel WTW. Substituting that value into the above equation results in 80.4 gCO_2e100/MJ.

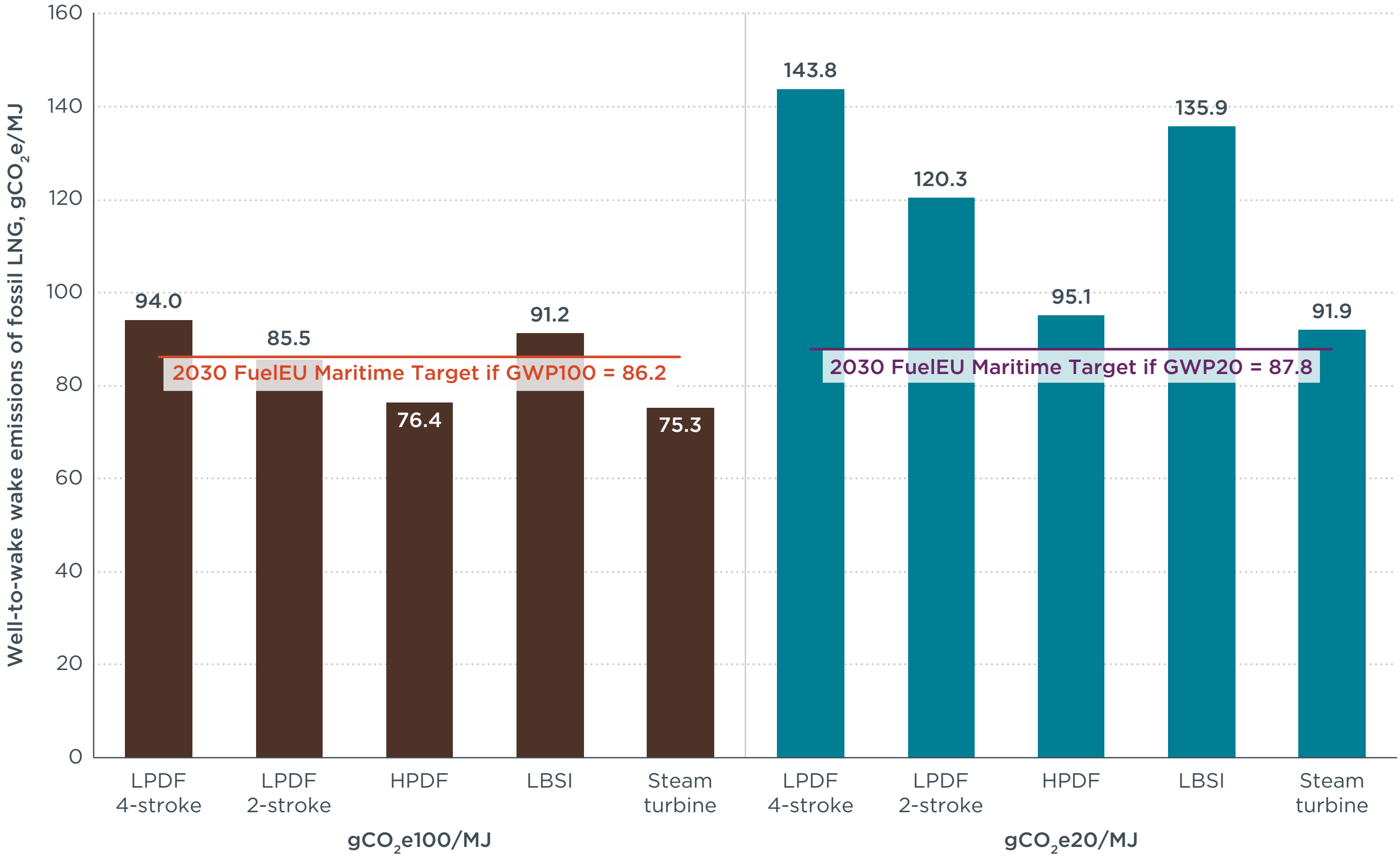


Figure 16. Well-to-wake carbon dioxide equivalent emissions (using FuelEU Maritime assumptions) using 100% fossil LNG compared to 2030 FuelEU Maritime targets.

Table 8. Assumptions for FuelEU Maritime analysis.

Well-to-tank			Tank-to-wake			
MJ/g LNG	gCO_2e100/MJ	gCO_2e20/MJ	gCO_2/g LNG	gN_2O/g LNG	Methane slip (%)	Engine Type
0.0491	18.5	35.0[a]	2.755	0.00011	3.1%	LPDF, 4-stroke
					1.7%	LPDF, 2-stroke
					0.2%	HPDF
					2.63%[b]	LBSI
					0.01%[b]	Steam turbine

[a] ICCT assumption for how FuelEU Maritime WTT emissions might change if calculated using GWP20 based on the ratio of WTT CO_2e20 to CO_2e100 from Comer and Osipova (2021) excluding the influence of black carbon emissions. [b] Assumptions from Faber et al. (2020) because FuelEU Maritime does not contain assumptions for methane slip for these engines.

As currently structured, FuelEU Maritime rewards the use of inefficient steam turbines because it regulates emissions per unit of “energy in” provided by the fuel rather than emissions per unit of “energy out” from the engine, which ignores the differences in fuel efficiency among engines. To set conditions such that it would not be possible to use 100% fossil LNG in marine engines, the 2030 FuelEU Maritime target would need to be at least a 17% reduction from baseline if FuelEU Maritime remains regulated on the basis of GWP100 (see Figure 16). The FuelEU Maritime initiative could also be amended to regulate based on GWP20 instead of GWP100. If so, the 2020 baseline would increase only slightly from 91.7 gCO_2e100/MJ to 93.4 gCO_2e20/MJ (Transport & Environment, 2022) because most fuel consumed on voyages to, from, and between EU ports in 2020 consisted of nonmethane marine fuels such as HFO, VLSFO, and MGO. In this case, only steam turbines would comply with FuelEU Maritime because all internal combustion engines would result in WTW emissions higher than baseline (Figure 17). Even so, ships would likely blend renewable LNG into fossil LNG to comply. Also, if ships over-complied by using LNG between 2025 and 2030, they could spend down any banked surplus before blending.

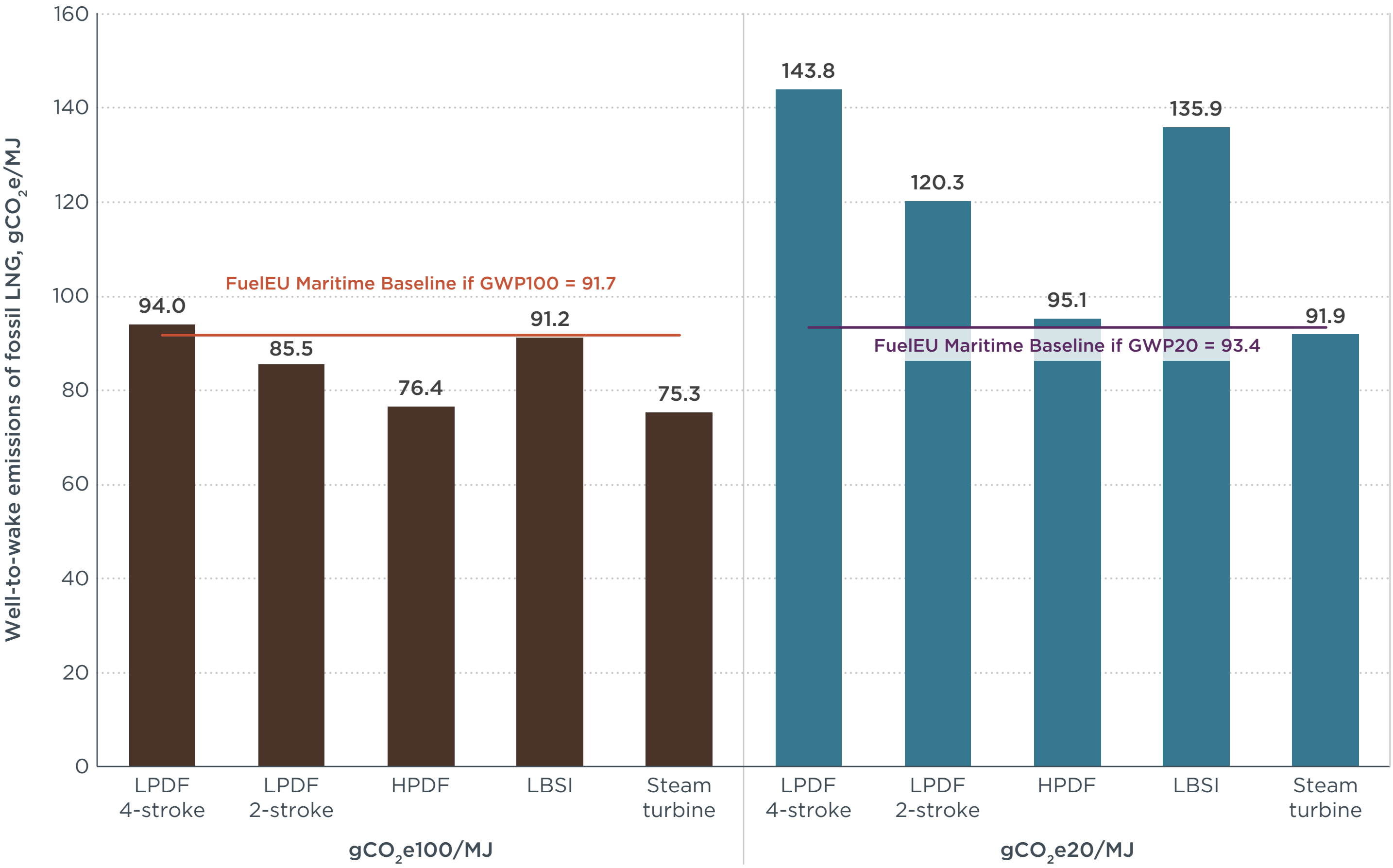


Figure 17. Comparing the FuelEU Maritime baseline to well-to-wake CO_2e emissions of fossil LNG in each engine type using GWP100 and GWP20.

By 2050, FuelEU Maritime requires a minimum 75% reduction from the baseline, meaning a ship's fuel mix must emit less than 22.9 gCO_2e100/MJ or below 23.4 gCO_2e20/MJ. A ship using 100% renewable LNG could comply with this 2050 FuelEU Maritime standard but not always. We found that the two most likely sources of renewable LNG are bioLNG made from agricultural residues and e-LNG. As shown in Figure 18, HPDF engines can always comply with the 2050 FuelEU Maritime targets if operated using the two most likely sources of renewable LNG. Steam turbines can as well, but we do not expect many steam turbines to be in use in 2050 because they are much less efficient, and therefore more expensive to operate, than their internal combustion counterparts. Ships using other engines would have a harder time complying. If FuelEU Maritime continues to be regulated on GWP100, LPDF 2-stroke engines could only comply using e-LNG, not bioLNG. If FuelEU Maritime were to be regulated on GWP20, only the HPDF and steam turbine engines would comply.

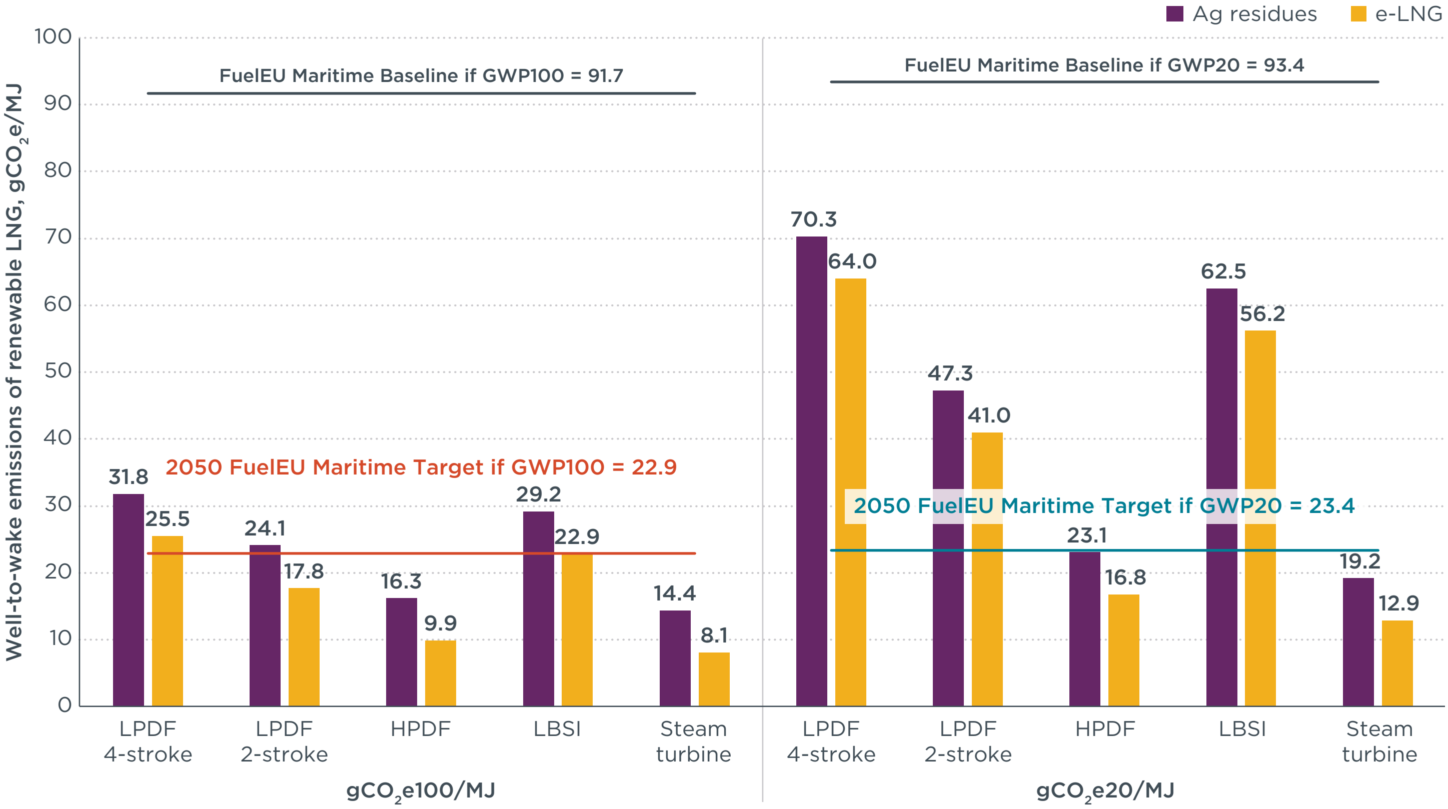


Figure 18. Well-to-wake carbon dioxide equivalent emissions using FuelEU Maritime assumptions from using two sources of 100% renewable LNG in various engines compared to 2050 FuelEU Maritime goals.

Beyond renewable LNG, the FuelEU Maritime initiative could force a shift to other fuels such as synthetic diesel, green methanol, green ammonia, and green hydrogen. Though we did not analyze the potential for LNG-fueled ships to switch to these alternatives, some LNG-fueled ships today are using LNG cargoes as their fuel (i.e., LNG tankers) and others have specialized LNG fuel tanks. In these cases, a switch to the alternatives would require either retrofits or replacement of the engines, fuel tanks, and fuel systems, except for drop-in fuels like synthetic diesel.

OTHER IMPLICATIONS AND ALTERNATIVES

Two of the most abundant sources of renewable LNG in the future considered in this analysis are e-LNG from renewable electricity and LNG produced from the methanation of gasified biomass. However, neither of these fuel pathways is necessarily cheaper or more commercially feasible when dedicated to producing LNG; synthetic drop-in diesel and methanol produced from either renewable electricity (via electrolysis) or gasified biomass are estimated to have similar production costs and technical constraints as producing LNG (Baldino et al., 2018). These liquid fuels could be supplied via existing distribution networks and, in the case of synthetic diesel, used in existing ships. Furthermore, these pathways do not risk methane leakage throughout the supply chain nor any methane slip. Therefore, drop-in liquid fuels could be a viable alternative to LNG as they can offer similar or greater GHG savings compared to conventional fuels and would generate substantially lower methane emissions.

Even if shipowners, operators, or charterers were willing to pay for renewable LNG, and if the government were willing to subsidize its use, the supply might not be available. LNG refineries take approximately 4 years to construct, based on a techno-economic assessment conducted in the European Union by Hönig et al. (2019). Facilities generally take several additional years to reach full operational output due to supply and maintenance delays. Less information is available on the ramp-up time for renewable LNG facilities; however, recent project announcements such as the Gladö Kvarn biogas plant expansion in Norway indicate that plants could be constructed in less than half the time (Sherrard, 2022). LNG facilities that source biomethane from aggregated sources such as dairy farms are expected to take the longest time to scale up because of significant pipeline infrastructure demands. Additionally, there will be competing uses for renewable LNG feedstocks. We have already accounted for biomass residues that could be used for sustainable aviation fuel in this analysis. However, in the industrial sector it is more efficient and cost-effective to use biomethane on-site for heat and power rather than to aggregate it from small sources and distribute it via pipeline to centralized upgrading systems. Because of methane slip and additional leakage during gas upgrading, biomethane also has a lower life-cycle CO_2e footprint when it is consumed directly on-site (Zhou et al., 2021).

WAYS TO AMEND POLICY

The most direct, prescribed pathway for decarbonization that currently exists in the EU shipping sector, especially covering the time between now and 2030, is the FuelEU Maritime proposed regulation. However, FuelEU Maritime could be amended to do more to promote a transition away from using LNG in engines prone to methane slip and toward fuels with low WTW CO_2e emissions. Based on the analysis presented in this report, we suggest the following:

Regulate FuelEU Maritime based on CO_2e20 rather than CO_2e100. Because methane's 20-year GWP is nearly three times higher than its 100-year GWP, regulating fuels based on their CO_2e20 emissions intensity would reward minimizing methane slip and promote the use of LNG in low-methane-slip engines such as HPDF. It would also promote the use of renewable fuels and phase out the use of fossil LNG as a marine fuel faster than if it continues to regulate based on GWP100. This would create an incentive to limit methane emissions this decade, which is helpful given that the IPCC estimates that methane emissions need to be cut by one-third from 2019 levels by 2030 to limit temperature rise to 1.5°C (IPCC, 2022).

Establish a minimum 75% CO_2e reduction threshold for bio and e-fuels under FuelEU Maritime. If bio and e-fuels, including renewable LNG, were required to achieve a 75% reduction from the GWP100 baseline or a 65% reduction from the GWP20 baseline to qualify for credits under FuelEU Maritime, it would require using steam turbines, low-methane-slip engines such as HPDF or low-WTW fuels in LPDF 2-stroke engines in the case of the 75% GWP100 reduction and only steam turbines or HPDF engines in the case of the 65% GWP20 reduction. This is different from the EU Renewable Energy Directive (RED II), which requires transport biofuels to achieve at least a 50%–65% reduction from a GWP100 baseline and transport e-fuels to achieve at least a 70% reduction. The reason for this suggestion is that the current 65% reduction from the GWP100 baseline for biofuels and the 70% reduction for e-fuels would allow the use of bioLNG and e-LNG in any LNG engine, even those with the highest methane slip. The more stringent thresholds would promote investments in alternative fuels that offer more than a marginal WTW benefit and that support the long-term transition to zero-emission vessels.

Separately, note that Article 11 of the EU's Alternative Fuel Infrastructure Regulation proposal would require EU member states to ensure that they provide enough LNG refueling points at key ports to enable ships to sail along the Trans-European Transport Network (TEN-T) by 2025. Our results suggest that mandating investments in LNG infrastructure could be counter to the EU's climate goals unless they are used solely for renewable LNG and to fuel ships that use low-methane-slip engines such as HPDF.

Policymakers could also set a zero date for FuelEU Maritime and accelerate the pace of reductions. The current FuelEU Maritime proposal does not require a complete transition to zero-emission vessels. The European Union, meanwhile, has a net-zero by 2050 target for its economy (European Commission, 2021a). At a minimum, a zero or near-zero WTW requirement for marine fuels therefore seems appropriate. Earlier ICCT analysis found that zero-by-2050 for shipping can be aligned with a well-below 2°C future, but only if emissions begin to fall immediately (Comer, 2021). The current FuelEU Maritime 2030 requirement is a 6% reduction in WTW CO_2e100 emissions from baseline, which enables the use of fossil LNG in LPDF 2-stroke engines, HPDF engines, and steam turbines. If the pace of reductions were accelerated by 5 years, the 2030 requirement would be a 13% reduction from baseline. In this case, only HPDF engines and steam turbines would comply if using fossil LNG. Ships using other engines would need to use alternative fuels, blend in renewable LNG, or use credits earned in earlier years or purchased from overperformers.

CONCLUSIONS

We estimated the 2030 demand for LNG used by ships on voyages to, from, and between EU ports, compared it to the potential supply of renewable LNG, and estimated the life-cycle (well-to-wake) GHG emissions of using various proportions of renewable LNG. We project that demand for LNG will triple between 2019 and 2030. The supply of renewable LNG is a function of the price users are willing to pay, and we estimate that renewable LNG is likely to be at least seven times more expensive than fossil LNG in 2030. Therefore, policy support would be needed to create an incentive for its use.

We modeled three policy scenarios whereby the European Union offers a subsidy to use renewable LNG. Each scenario resulted in a different mix of fossil and renewable LNG and therefore different well-to-wake CO_2e emissions. Offering no subsidy meant that 2030 LNG demand would be met using 100% fossil LNG, and with a €25/GJ subsidy, only 4% of LNG demand could be met with renewable LNG. Only LNG made using inexpensive landfill gas would be cost-competitive with fossil LNG and, unfortunately, this feedstock is in limited supply. Doubling the subsidy to €50/GJ (€2,400/t LNG) would enable the use of 100% renewable LNG because it would create price parity between more expensive bioLNG fuels made from agricultural residues as well as e-LNG. However, this level of price support would require annual public expenditures of €17.8 billion in 2030.

Using 100% renewable LNG would reduce 2030 WTW CO_2e emissions from LNG-fueled ships by 79% on a GWP100 basis, and 65% on a GWP 20 basis, compared to using 100% fossil LNG in 2030. Compared to 2019, 2030 WTW CO_2e emissions using renewable LNG are 38% lower on a GWP100 basis but 6% higher on a GWP20 basis, given growth in the LNG-fueled fleet. EU law requires reducing economy-wide GHG emissions at least 55% below 1990 levels by 2030, which would require a 41% reduction in GHG emissions from a 2019 baseline. This underscores the importance of evaluating CO_2e emissions using both GWP100 and GWP20, especially when near-term climate impacts are important to policymakers, and especially for fuels consisting of short-lived climate pollutants such as methane.

Because of upstream methane leakage and downstream methane slip, even when using 100% renewable LNG, absolute methane emissions from LNG-fueled ships would double from 2019 to 2030. The only way that using renewable LNG could be compatible with the spirit of the reductions called for in the Global Methane Pledge would be to reduce total 2030 methane emissions from LNG-fueled ships by at least 65%. Doing this would require using the best-in-class engine technology (HPDF) and reducing upstream methane leakage by at least 30%. These reductions would need to deepen each year to counteract growing demand for LNG.

We also found that the FuelEU Maritime proposal could help shift ships to renewable LNG, but only by 2050 when ships must emit at least 75% less WTW CO_2e100 than a 2020 baseline. We identified ways that FuelEU Maritime could be improved, including regulating based on CO_2e20 and setting a minimum GHG reduction threshold for all fuel pathways.

Other fuels could offer low life-cycle emissions without the methane problem. Synthetic diesel and green methanol have similar production costs and technical constraints as producing renewable LNG, but these liquid fuels are easier to store onboard than LNG and could be supplied via existing distribution networks. Synthetic diesel can be used in conventional marine engines or dual fuel engines without modification, including those on existing LNG-fueled ships, and methanol can be used in new or modified dual fuel engines. Future work can focus on the potential demand and supply for nonmethane fuels to support the transition to zero-emission vessels.

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