Role of bio-LNG in shipping industry decarbonisation

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List of Acronyms

AD	Anaerobic digestion
BECCS	Bioenergy with carbon capture and storage
CAPEX	Investment cost
CII	Carbon Intensity Indicator
DAC	Direct air capture
DM	Dry matter
EAC	Energy Attribute Certificate
EEDI	Energy Efficiency Design Index
EEXI	Energy Efficiency Existing Ship Index
EPA	Environmental Protection Agency
ETC	Energy Transition Commission
EU	European Union
FAME	Fatty acid methyl esters
GHG	Greenhouse gas
GO	Guarantees of Origin
GWP	Global Warming Potential
HPWS	High-pressure water scrubbing
HVO	Hydrotreated vegetable oil
IEA	International Energy Agency
IMO	International Maritime Organization
IPCC	Intergovernmental Panel on Climate Change
IRENA	International Renewable Energy Agency
ISO	International Organization for Standardization
LBM	Liquefied biomethane
LCA	Lifecycle analysis
LCFS	Low Carbon Fuel Standard
LHV	Lower heating value
LNG	Liquefied natural gas
MEPC	Marine Environment Protection Center
MGO	Marine gasoil
MSW	Municipal Solid Waste
OPEX	Operational cost
PEM	Polymer Electrolyte Membrane
REC	Renewable Energy Certificate
RED	Renewable Energy Directive
RFS	Renewable Fuel Standard
RGGO	Renewable Gas Guarantees of Origin
SSP	Shared socio-economic pathway
UCOME	Used cooking oil methyl ester
VS	Volatile solid

Executive Summary

Bio-LNG as a shipping fuel

The global shipping industry is faced with one of its biggest challenges in decades, as it seeks to comply with the stringent greenhouse gas (GHG) emissions reduction targets set by IMO and proposed by the European Union. In the last two decades, the use of fossil liquefied natural gas (LNG) has gained traction due to low onboard emissions of local air pollutants and CO_2 emission savings compared to traditional marine fuels such as heavy fuel oil and marine diesel. However, fossil LNG alone cannot be considered a long-term solution to the decarbonisation challenge as, despite the significant emissions reductions it offers, it is still a fossil fuel. However, other LNG alternatives exist, more specifically, bio-LNG produced from sustainable biomass sources, which can provide major GHG emission reductions on a full lifecycle, or well-to-wake basis compared to fossil fuels.

Bio-LNG has a number of advantages in its use as a marine fuel: it can be produced via degradation of second-generation biomass (including agricultural waste, organic waste, manure, and sewage sludge) and, unlike most biodiesels, its production will not cause interference to the food supply chain and, at the same time, it avoids land use changes. In addition, production of bio-LNG can avoid the emission of methane, which is a powerful greenhouse gas resulting from the natural degradation of waste to the environment. Among the potential technologies required to produce alternative fuels, bio-LNG production is considered one of the most mature. Moreover, the use of fossil LNG (and bio-LNG) as a marine fuel is an established, mature technology, with many LNG-fuelled ships in operation, and bio-LNG can be used as a drop-in fuel in existing LNG-fuelled engines and can also be transported, stored and bunkered in ports utilising the existing LNG infrastructure.

However, many questions arise when considering the role that bio-LNG could play in the decarbonisation of the shipping industry. Fuel availability, cost, lifecycle emissions and logistics are some of the main issues that need to be addressed. This study aims to answer these questions and provide an overview of the applicability of bio-LNG as a marine fuel and gain an in-depth understanding of whether LNG and bio-LNG can provide a realistic pathway for the shipping industry to achieve GHG emission reduction targets in a sustainable manner.

Bio-LNG availability for shipping

Liquefied biomethane, or bio-LNG, produced from sustainable biomass resources has the potential to meet a significant proportion of future shipping energy demand, taking into account growing biomass demand from other sectors such as wood and paper production, industrial feedstocks, heat and, power generation, aviation and heavy-duty road transportation.

Bio-LNG (also called liquefied biomethane, or LBM) is derived from the liquefaction of biomethane, a gas that is produced from the degradation of biomass, either following chemical or thermal process routes. The main conversion routes are anaerobic digestion, involving biogas generation and upgrading, of wet biomass and thermal gasification of woody biomass. One of the key challenges of supporting the shipping industry with biofuels such as bio-LNG is to assess whether there will be enough sustainable biomass available to produce fuels for the maritime sector.

Four main categories of sustainable biomass feedstock for biomethane can be used: i) non-food energy crops; ii) agricultural residues; iii) manure and other biowaste material; iv) forestry and wood waste. The sustainable biomass energy potential is defined as the fraction of the available global biomass that can be exploited while fulfilling sustainability requirements such as the conservation of ecology, biodiversity, soil and water quality. The global demand for biomass is expected to rise over time from different sectors of human activity (i.e. material uses such as wood and paper and industrial feedstocks, aviation, heat and power generation and transportation, including aviation and heavy-duty road transportation), and this will likely increase the price of feedstock due to the limited availability of the resource. When considering future scenarios of the competing uses of sustainable biomass between sectors and the potential role of biomethane as renewable gas in a world on a pathway to net zero emissions by 2050, it is clear that there will not be enough biomass available to meet the energy demand of the entire maritime transport sector. However, there will be enough sustainable biomass to cover a significant portion of the energy demand for fuels and make a major contribution to maritime decarbonisation (see Figure 1).

The fraction of sustainable biomass that could be available to produce bio-LNG for the shipping sector was evaluated using recent analysis and forecasts by the IEA and Navigant. From a bottom-up perspective, of the total sustainable biomass theoretically available worldwide, a fraction between 40-50% could be considered practically harvestable. Such harvestable biomass will serve several uses, among which is the production of biomethane for heat and power generation and for transport.

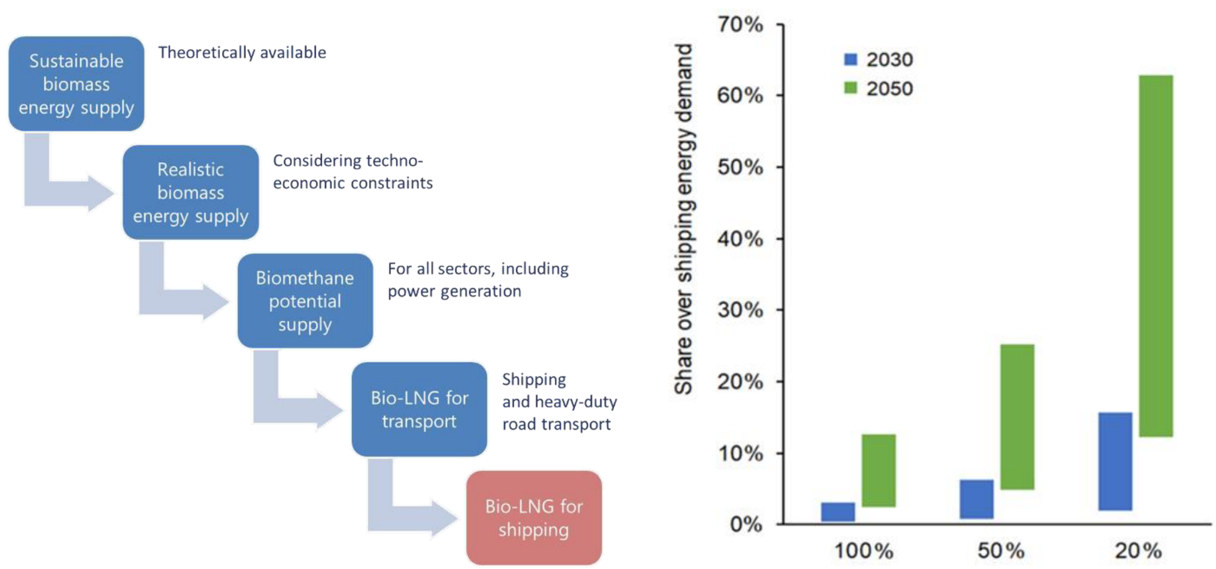


Figure 1 – Scheme for the evaluation of bio-LNG availability for shipping (left) and potential availability of bio-LNG for shipping sector in 2030 and 2050 over total shipping energy demand, with different blending rates with fossil LNG (right)

Depending on the future competition with other renewable gases such as hydrogen, a fraction of the produced biomethane will be used for transport. In an optimal scenario, as evaluated by Navigant for the European context, around 80% of the biomethane available for transport would be used for the shipping sector, while the remaining part will be used in heavy-duty long-distance transport (trucks). Pure bio-LNG could then cover up to 0.4-3.1% in 2030 and 2.4-12.6% in 2050 of the total energy demand for shipping fuels, while if it is considered as a drop-in fuel blended with fossil LNG, bio-LNG could cover up to 15.7% and 62.9% of the total energy demand in 2030 and 2050, respectively, assuming a 20% blending ratio.

Bio-LNG could therefore become a viable drop-in biofuel that can be blended with fossil LNG to comply with the IMO targets by 2030 and 2050, as there could be enough biomethane to cover a significant fraction of the future shipping demand in 2030 and 2050, assuming continued growth in the LNG-fuelled shipping fleet. Bio-LNG can therefore play an important role in the decarbonisation of the maritime sector, depending on international policies deployed, market prices and technology advancements in biofuel production and use.

Fuel cost

Bio-LNG's average cost is currently around 30 $/GJ, but this could fall to around 20 $/GJ with plant scale-up and efficient logistics by 2050. This makes bio-LNG one of the most cost-effective alternative marine fuels, cheaper than biomethanol and electrofuels, including e-ammonia and e-methanol.

The cost of bio-LNG as bunker fuel depends on the type of biomass feedstock, fuel production technology, and on logistics and transport modes. The current global average cost of producing biomethane through anaerobic digestion of biomass is around 19-20 $/GJ and could fall to 15 $/GJ by 2040. Since this technology is very mature and significant innovations are not expected, a reduction in costs can be achieved solely by increasing the production rate and the size of the digesters and of the upgrading units. The gasification pathway is currently significantly more expensive, with an average production cost of 28-33 $/GJ. However, further development of the technology and scale-up could lower the biomethane cost to around 12-19 $/GJ in 2050, thus matching the cost of biomethane obtained from anaerobic digestion.

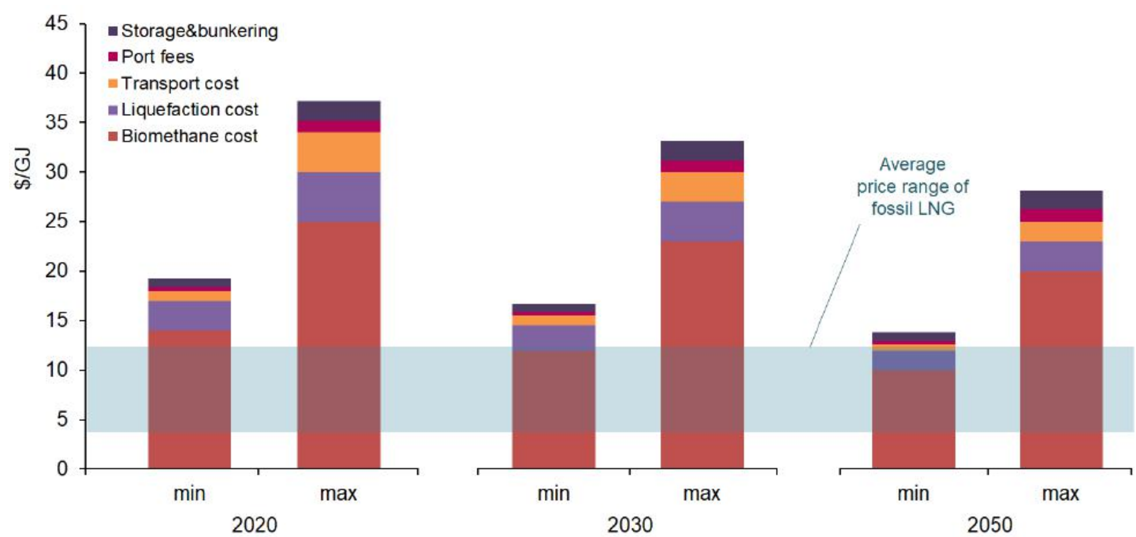


Figure 2 - Bio-LNG from anaerobic digestion total cost range in 2020, 2030 and 2050, compared with fossil LNG bunker price (range)

Biomass gasification is an important step towards the global use and trading of biomethane due to its suitability for large-scale centralised production. However, suitable policies and incentives are required to fund research and pilot plants around the world in order for large-sized gasification plants to become a reality. Currently, bio-LNG would cost around 3-4 times higher compared to the average fossil LNG bunker price (Figure 2), excluding the most recent price spike. The average cost for delivered bio-LNG declines by around 30% in 2050 compared to today's values, mainly driven by the reduced cost of producing biomethane in large-scale anaerobic digestion plants. Biomethane production accounts for around 70% of the overall cost of bio-LNG to shipowners, liquefaction and transport accountable for another 20%, while bunkering and port fees add up to the final 10%. In the best-case scenarios, i.e. biomethane from manure and agricultural residues produced in Asian regions and delivered to major eastern ports, the cost of bio-LNG could fall to 20$/GJ and 15 $/GJ by 2030 and 2050, respectively. Although the cost of bunker bio-LNG is relatively high compared to fossil fuels, it is cheaper than most other alternative fuels (Figure 3). Sustainable biofuels such as UCOME made from waste cooking oil are generally cheaper. However, feedstock availability is low. Biomethanol and bio-LNG have similar costs per unit of energy, with biomethanol being slightly more expensive due to the gasification technology required, which is more expensive compared to anaerobic digestion.

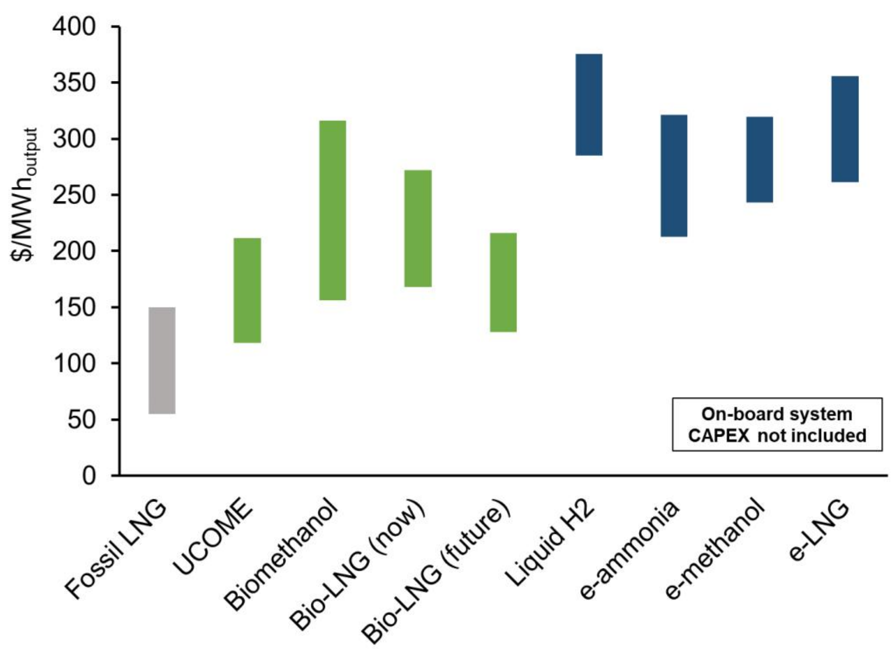


Figure 3 - Alternative fuels energy cost comparison, per unit of output energy from the engine. It includes transport and bunkering costs (bio-LNG and e-LNG transport costs are based on fossil LNG, thus implying the use of existing infrastructure). The assumed engine conversion efficiency is 45% (50% for liquid hydrogen used in a fuel cell). (Note, the higher and lower ends of the spectrum represent 2030 and 2050 costs, respectively).

Among the electro-fuels, liquid hydrogen has the lowest production costs. However, the high transport and delivery costs make it the most expensive, even without considering the investment for the fuel cell propulsion system. E-ammonia is generally cheaper to produce as, unlike e-methanol and e-LNG, its production does not require carbon dioxide (CO_2). However, there are uncertainties about fuel handling systems and engine technology which have not yet been developed; further reliable data on onboard conversion system costs and efficiency are not available. The total energy cost of e-LNG is slightly higher compared to methanol, mostly due to the production process, which requires more CO_2 input and liquefaction. E-methanol and e-LNG have similar costs for transport and bunkering per unit of energy. While a gallon of methanol is cheaper to store and transport compared to an equivalent amount of LNG, it carries far less energy due to its lower energy density. In summary, despite its relatively high cost compared with its fossil LNG equivalent, bio-LNG emerges as a future-proof candidate fuel for decarbonisation of shipping when compared to other alternative fuels. Indeed, it is generally cheaper than biomethanol produced from the gasification of biomass and may soon be competitive with sustainable biodiesel (i.e. produced from non-edible sources), which has a relatively low cost but suffers from availability issues. It is important to note that both biofuels and electrofuels are more expensive than fossil fuels, and therefore a carbon pricing scheme is required to foster their adoption. The wide ranges of price and GHG emissions (see next paragraph) found in the analysis dramatically increase the complexity of comparing different alternative fuels from the economic perspective, and therefore carbon pricing was not considered in this study.

GHG emissions

In general bio-LNG can provide GHG emissions reduction up to 80% compared to marine diesel, if methane leakage in the production process and on-board methane slip are minimised. In the specific case of bio-LNG produced from anaerobic digestion of manure, if avoided emissions are taken into account, then bio-LNG can achieve negative emissions ranging from ranging from minus 121% to 188% compared with diesel

Bio-LNG can provide significant GHG emissions reductions compared to fossil fuels, depending on the biomass feedstock used, the biomethane production method, the carbon footprint of electricity used in the production process and the practices adopted for storing the digestate and upgrading the biogas. In our analysis, uptake of atmospheric CO_2 from biomass was not considered, following the carbon-neutrality assumption for biofuels and implying that CO_2 emissions due to onboard combustion of the biofuel are offset by CO_2 absorbed by biomass from the air during its growth. Importantly, the use of manure avoids methane (a powerful greenhouse gas) emissions into the atmosphere, as current management practices involve using manure directly as a fertiliser on the fields, where it decomposes, releasing methane into the atmosphere. Bio-LNG can play a significant role in reducing GHG emissions in shipping, but important issues need to be addressed, including methane leakage in the anaerobic digestion process (a closed storage system is required for the digestate, and leakage from biogas upgrading must be minimised) and methane slip onboard (which has a strong impact on the overall well-to-wake emissions).

When comparing bio-LNG emissions with those of other alternative fuels, it becomes clear how this fuel can be competitive with other alternatives (Figure 4). The highest emission reductions, up to 77%, are obtained when bio-LNG is produced from manure, with low methane slip onboard a ship. In the specific case of bio-LNG produced from anaerobic digestion of manure, if avoided emissions are taken into account, the resulting GHG emissions are negative, ranging from minus 121% to 188%. It should be noted that it is also possible to obtain biomethanol from biogas. However, the overall fuel production costs per unit of energy are higher due to the additional steps required (reforming and methanol synthesis).

Electro-fuels achieve very low well-to-wake GHG emissions. However, they cannot reach net zero emissions due to the non-negligible carbon footprint of the renewable energy required for hydrogen production and fuel synthesis (wind energy was considered in the analysis). E-LNG produced from renewable energy and CO_2 captured from the air, or biogenic sources can be competitive with other electro-fuels in terms of lifecycle equivalent CO_2 emissions. However, methane losses along the value chain and onboard the ship can significantly increase the overall emission balance and must therefore be kept at a minimum. Since the emissions are considerably lower for synthetic LNG compared to fossil LNG, the relative impact of gas slip is higher. Assuming that methane losses along the value chain and onboard methane slip are minimised, the use of e-LNG offers emissions reduction up to 80% compared to fuel oil.

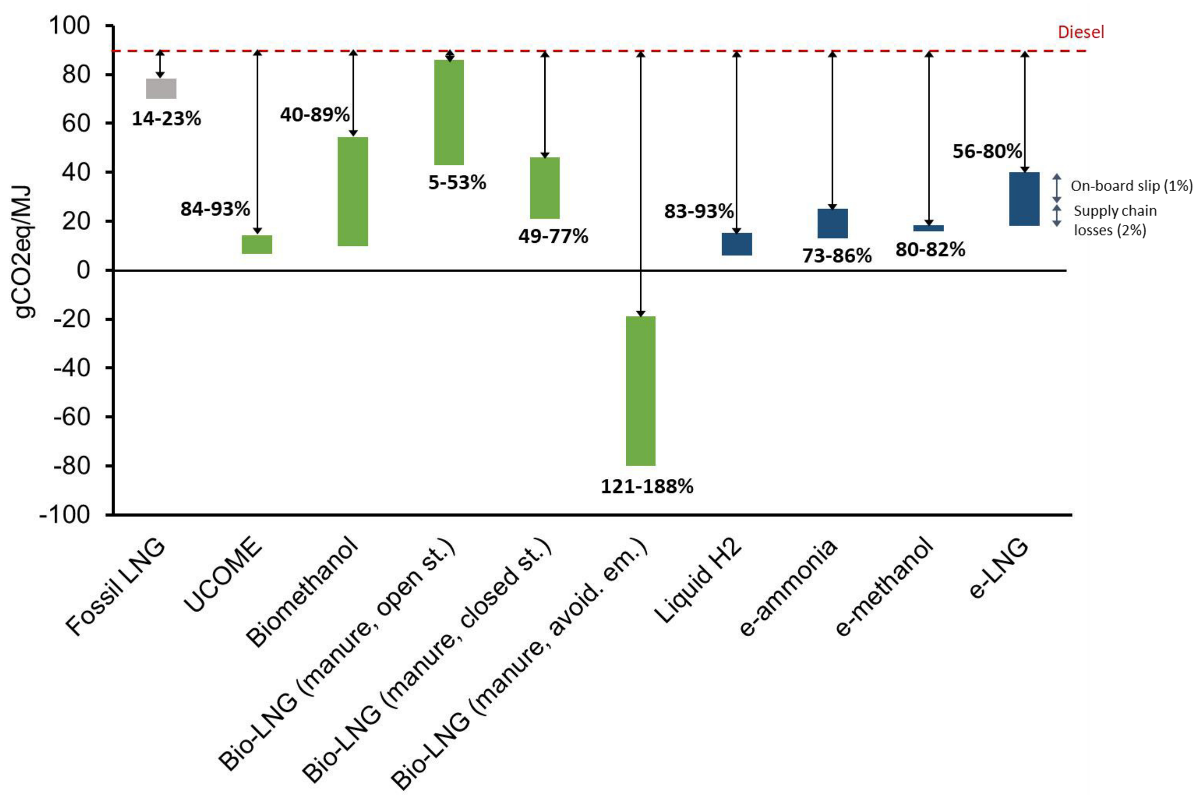


Figure 4 – Well-to-wake GHG emissions of alternative fuels compared to diesel. Includes emissions during fuel production and onboard emissions. Electrofuels are produced with wind energy and their cost range is estimated for 2050.

Logistics of bio-LNG

The use of existing natural gas and LNG infrastructure is key to abate the logistics costs related to biomethane transport, liquefaction and bunkering.

The value chain of bunker bio-LNG differs from that of fossil LNG as it requires biomass supply chains for biomethane production plants and transport of the gas to the bunkering hubs. Part of this value chain can overlap with existing natural gas infrastructure, thus reducing logistics-related costs (Figure 5). Optimising the size and location of future biomethane plants can help to reduce the cost of collection and transport of biomass to the production plant. Decentralised and centralised configurations both offer pros and cons, and an intermediate solution between the two might be the most viable choice to limit the cost of biomethane at the plant gate. The best-case scenario is represented by medium size plants strategically located close to farms and biomass waste collection points, such as cities for food waste and slurry, animal farms for manure and agricultural sites for residues. Dedicated supply chains for shipping involving onsite liquefaction and transport of bio-LNG by dedicated trucks and bulk carriers are appropriate for demonstration purposes but do not make economic sense from a large-scale implementation perspective due to the very high infrastructure costs.

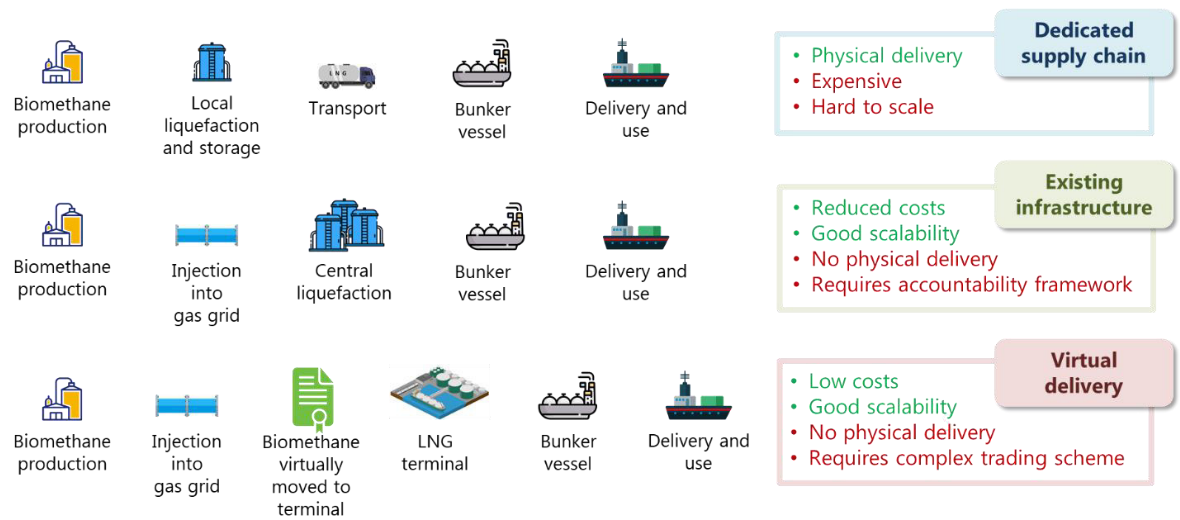


Figure 5 - Different possible configurations for bio-LNG supply chain for maritime transport with pros and cons

Utilising existing LNG infrastructure and logistics should therefore be preferred. The lowest costs are achieved when biomethane is injected into the gas grid and virtually transported to liquefaction plants and LNG terminals using the existing infrastructure and Green Gas Certificates and Biomethane Guarantees of Origin for trading. However, this would require an appropriate regulatory framework, as already happens for green electricity in some regions of the world (i.e. Europe).

Bio-LNG adoption

Bio-LNG from biogas upgrading and e-LNG from renewable energy are among the most viable options to deacarbonise shipping, if sufficient carbon pricing is put in place.

The future fuel landscape and the rate of adoption of alternative fuels in shipping will depend on the interplay of several factors such as the development of engine technologies and onboard fuel storage systems, fuel production costs, fuel handling and safety practices, infrastructure development for alternative fuel transport and bunkering, the relative GHG footprint of different fuelling solutions, and regulation, including carbon pricing, and policy incentives for the adoption of GHG mitigation measures.

It is, therefore, difficult to make forecasts about the future fuel mix in shipping. However, it is possible to make a simplified assessment of the attractiveness of different fuels based on the future cost for fuel and onboard system and related GHG emissions.

A fuel adoption assessment model was used to evaluate the adoption of alternative fuels in shipping from now to 2030 and 2050. The total cost of ownership for each fuel was calculated year by year, and potential adoption pathways from the shipping fleet were evaluated considering two different global scenarios for the pathway of society towards sustainability and different assumptions on future carbon prices. The analysis was based on two shared socioeconomic pathways (SSPs) produced by IPCC, which describe global futures for human society and economy following either sustainability principles or conventional development. The total emissions from the maritime sector were then compared with IMO targets to check whether the adoption pattern would be compatible with future emission reduction goals. Onboard, or tank-to-wake, carbon emission factors were used in the analysis, as this is the methodological approach currently underpinning IMO decarbonisation regulations. Bio-LNG from anaerobic digestion of waste biomass represents an attractive choice for shipowners due to the fact that the fuel cost is lower compared with other alternative fuels and the onboard energy conversion technology is mature and well-understood, with existing guidelines and established practices. Moreover, there is an existing (and developing) infrastructure for transport and bunkering, and the presence of a small but rapidly growing fleet of vessels that are currently running on fossil LNG represents an existing asset base for the adoption of bio-LNG, especially as a drop-in fuel. This is not the case for other alternatives like methanol and ammonia. The main barriers to its widespread adoption are related to fuel availability and to the current absence of proper regulations for assessing the lifecycle GHG emissions that may vary substantially depending on biomass feedstock and fuel production technology. However, these issues are not unique to bio-LNG and affect other alternative fuels.

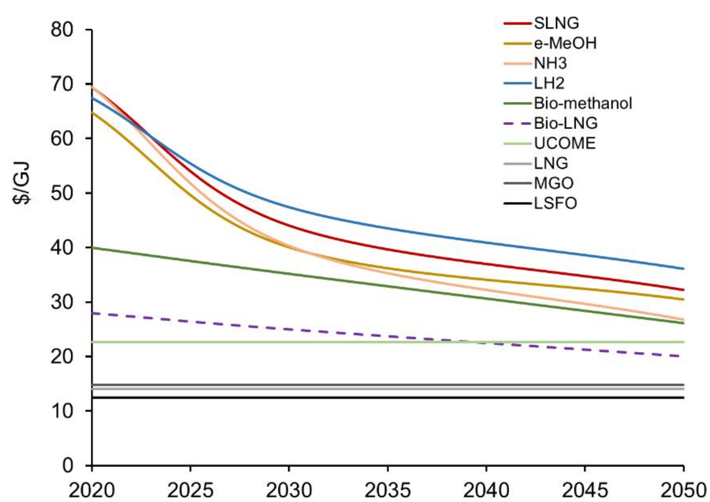


Figure 6 - Cost evolution of fossil fuels and renewable fuels (including distribution and storage cost) over time. Cost of fossil fuels is assumed constant due to the unpredictability of future markets and policies.

Since e-LNG appears to have cost and emission performances similar to other electro-fuels (Figure 6), it could gradually replace bio-LNG in the long term as the demand for alternative low-carbon fuels increases and the price of hydrogen decreases. On a simple production cost basis, e-ammonia is the most important competitor among the electro-fuels as its production does not require CO_2 (which is an added cost for renewable methanol and e-LNG), however many uncertainties related to the combustion technology, the onboard emissions and safety issues still have to be addressed.

Regulatory aspects and barriers

The adoption of bio-LNG in shipping will be linked to the widespread use of biomethane across other sectors. It will require national and international standards for biomethane injection into gas grids and Certificates of Origin schemes to efficiently trade biomethane in its gaseous and liquefied forms and to reduce transportation costs.

The transportation sector has seen a growing s number of government policies and regulations over the past decade and a half to reduce greenhouse gas emissions, improve energy efficiency and support the development and deployment of renewables and other clean energy technologies. Many countries have implemented blending mandates and targets for biofuel use, especially on ethanol and biodiesel in land transport. Currently, no biomethane mandate exists in any single country. However, policies and measures are emerging regarding promoting biomethane or biogas, focusing on biomethane production technology, production capacity, and related infrastructure development.

Currently, Europe is the global leader in developing the biogas and biomethane industry. The region has the highest biogas production and upgrading plants and the largest installed capacity for generating raw biogas and purifying it for biomethane. The Renewable Energy Directive (RED) enforced in 2009 and the new RED (RED II) enforced in 2021 form the basis of EU regulations on biofuels. The RED II increases the mandatory 20% renewables target to at least 32% by 2030 with a 14% target for the transport sector, with a clause for a possible upwards revision by 2023. Besides the overall targets, Article 12 of the directive highlights biogas's importance and high GHG mitigation potential. Article 16 provides non-discriminatory transport and distribution charges for gas produced from renewable sources. In addition, the directive also enables double counting of the biomethane made from waste in the renewable energy target for the transport sector. More recent developments in Europe include the European climate law and the 'Fit for 55' package. In the near future, the upcoming FuelEU Maritime regulation may set increasingly stringent limits on the carbon intensity of vessels visiting the EU starting from 2025, likely providing a significant boost to the use of alternative fuels such as biomethane.

In the US, the Renewable Fuel Standard (RFS) is the primary federal policy supporting the use of biofuels. The production and usage of biofuels are promoted through the trading of Renewable Identification Numbers (RINs) under RFS. Besides the federal policies, Low Carbon Fuel Standard (LCFS) has been implemented in the states of California and Oregon. In Canada, energy policies that support the use of biogas and biomethane are usually happening at the provincial level. The credit system available in the US has also been adopted in several Canadian provinces, such as British Columbia. Unlike the EU, the incentives for biogas upgrading present in European countries are generally unavailable in North America. The existing incentives, such as RINs and LCFS credits, generally relate to natural gas road vehicles and electricity generation. There is a need for federal or country-level programs or incentives directly aiming to increase biomethane usage in shipping.

The main regulatory framework in the International Maritime Organization (IMO) is the Initial IMO Strategy on Reduction of GHG Emissions from Ships. The Initial Strategy implemented further phases of the Energy Efficiency Design Index (EEDI) and Carbon Intensity Indicator (CII) and promised to reduce GHG emissions from international shipping by at least 50% by 2050 compared to 2008. The time for developing the revised Strategy was set to be adopted in 2023 during MEPC 80. Despite not having a specific view on bio-LNG, IMO views biofuels in general as suitable for the existing fleet due to their drop-in capability to be blended with conventional marine fuels.

Two key regulatory challenges need to be addressed to enable the large-scale development and usage of biomethane for the shipping industry. First, there is a lack of commonly accepted standards for grid injection and vehicle fuel. Few biomethane standards exist but mainly at a national level, and technical specifications on the biogas quality requirements also vary across countries and regions. Efforts on standardisation among countries and regions are needed to make biomethane competitive and reliable in the marketplace. There is also a need for developing commonly accepted and preferably legally binding trading schemes specific to biomethane. The lack of a harmonised green gas certification system may hinder the smooth cross-border trading of biomethane.

Looking ahead

Just as the development of bulk LNG supply chains provided the platform for the uptake of fossil LNG as a marine fuel in shipping, the widespread adoption of biomethane across several sectors and the existence and development of an integrated global transportation infrastructure may be a significant accelerator for the use of bio-LNG in the shipping industry, recognising the competition from other sectors. Bio-LNG use in the transport sector, mostly for heavy-duty trucks and ships, will likely increase dramatically in the upcoming decades, and this will help to reduce the uncertainties and the costs related to fuel production and transport.

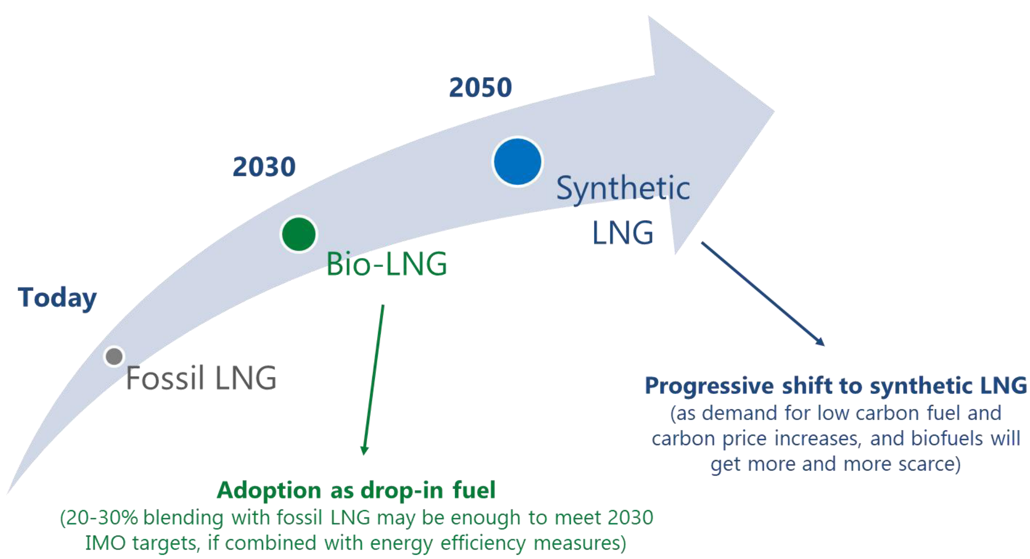


Figure 7 – Adoption pathway for bio-LNG and e-LNG in shipping

It should be stressed that carbon pricing schemes and appropriate regulatory frameworks are currently lacking and are essential for the adoption of bio-LNG as a shipping fuel. Even though there are still uncertainties related to bio-LNG as shipping fuel, mostly due to the huge scale-up of worldwide biomethane production required in the next years and the need for proper supporting policies for biomethane production and trading, it is clear that bio-LNG could provide shipowners with a realistic and incremental pathway for decarbonisation. Bio-LNG appears to be a robust alternative fuel solution for the decarbonisation of the shipping sector thanks to the mature and commercially available technologies for fuel production and use onboard and the competitive cost compared to other sustainable biofuels and electro-fuels. It is unlikely that bio-LNG in and if itself could completely decarbonize the shipping sector due to the limited global availability of biomass and the increasing demand for bioenergy from other sectors. However, in its role as a drop-in biofuel, bio-LNG can be blended with fossil LNG in relatively small amounts to reach the intermediate IMO targets for 2030, and the biofuel proportion in the mix can be increased to meet rising targets. Long-term (Figure 7) shipowners who have invested in the LNG technology pathway will need to shift to e-LNG.

1. Introduction

1.1. Background

International shipping accounts for about 3% of greenhouse gas (GHG) emissions worldwide. Under a business-as-usual scenario, GHG emissions are expected to increase by 50% to 250% by 2050. In April 2018, the International Maritime Organization (IMO) established its "Initial IMO Strategy on Reduction of GHG Emissions from Ships" to reduce GHG emissions and set targets to achieve the reduction in the future. Further energy efficiency design index (EEDI) phases were implemented based on the Initial Strategy. Various levels of emission targets have been set. Specifically, IMO commits to reducing CO_2 emissions per transport work by at least 40% by 2030 and 70% by 2050. It also set a target to reduce GHG emissions from international shipping by at least 50% by 2050 compared to 2008.

Several strategies can be applied by shipowners and relevant stakeholders to reach the goals set by IMO, such as improving the energy efficiency of the ships and adopting technical and operational measures to reduce fuel consumption (e.g. slow steaming). However, the adoption of alternative low-carbon fuels to replace fuel oil and gasoil seems inevitable.

In the last decade, the use of fossil liquefied natural gas (LNG) has begun to gain attention due to low onboard emissions of air pollutants and CO_2 emission savings compared to diesel. LNG is basically liquefied methane, stored at low temperatures (-160°C), that can be burned in gas engines to run propellers and electric generators for service loads. Bunkering infrastructure is currently developing, and today LNG is available in most major shipping hubs. Even though the ships in operation currently running on LNG are less than 0.2%, there are many new builds on order, and in the next years, the uptake of fossil LNG in shipping is expected to increase substantially, reaching 6% of the world fleet based on ships on order today [1]. The fraction of LNG ships is expected to increase even more in the future. However, this fuel cannot be considered a reasonable alternative to fuel oil in the long term due to the fact that it can provide only minor emission reductions (around 20%) compared to fuel oil [2].

Methane can also be produced in alternative and more sustainable ways. Bio-LNG is produced from biomass sources and can provide major GHG emission reduction from a cradle-to-grave perspective compared to fossil fuels. E-LNG can instead be obtained from renewable electricity used to produce hydrogen and carbon dioxide recovered from water and fluegas or air, respectively, and could provide even higher performances in terms of CO_2 emissions.

The reasons why the shipping industry should not overlook the application of liquefied methane are several and can be summarised as follows:

- Both fossil-based LNG and bio-LNG are considered clean fuels with a significant emission reduction of SO_x, NO_x, PM and unburned HC;
- According to the 2018 statistic review by BP [3], total world-proven reserves of natural gas reached 193,600 billion m^3 with a reserve to production ratio of 52.6 years. Given the availability, it is expected that oil and natural gas will continue playing an important role in supporting the shipping industry as fuel sources of choice for at least another 20-30 years;

- Bio-LNG can be produced via the degradation of biomass, including agricultural waste, organic waste, manure, and sewage sludge. Since bio-LNG can be produced from second-generation feedstock, unlike most biodiesels, its production will not cause interference to the food chain and, at the same time, avoids land use change. In addition, the production of bio-LNG could avoid the emission of GHG (i.e. methane) resulting from the natural degradation of waste to the environment;
- In the past 20 years, the cost of LNG per unit of energy output from ship engine has been comparable with that of fuel oil;
- Among technologies required to produce alternative fuels, the technology for bio-LNG production is considered one of the most mature technologies;
- The technologies required for onboard application of LNG (and bio-LNG) are mature, with almost 800 LNG-fuelled ships currently in operation (including LNG carriers);
- Bio-LNG can be used as a drop-in fuel, as it can be used in existing LNG engines with little or no modification and transported, stored and bunkered in ports utilising the existing LNG infrastructure.

The adoption of bio-LNG and e-LNG to gradually replace fossil LNG is therefore of great interest to shipowners that have already invested in LNG ship technologies or plan to do it sooner or later to comply with future IMO targets. However, many uncertainties lie behind bio-LNG as shipping fuel, and key questions regarding fuel cost, availability and lifecycle GHG emissions still need to be answered.

1.2. Objective of the study

In this context, the present study aims to provide an overview of the applicability of bio-LNG as a marine fuel and to gain an in-depth understanding of whether LNG and bio-LNG can genuinely support the shipping industry to achieve GHG emission reduction targets in a sustainable manner. In order to assess the sustainability of LNG and especially bio-LNG as a fuel for the shipping industry, it is necessary to consider not only its onboard application but also the whole value chain, including fuel production, transport and combustion.

1.3. Approach and timeframe

The study is structured into seven main chapters, addressing the main questions and issues regarding bio-LNG as future fuel for shipping.

- **Chapter 2 (bio-LNG fuel)** provides an introduction to bio-LNG, including the different technologies and methods for its production and the current development and use of biogas and biomethane around the world;
- **Chapter 3 (biomass availability)** aims to address the availability issue of bio-LNG for the shipping sector, providing an evaluation of future availability based on feedstock accessibility, geographical availability and future demand for biomethane from other sectors;
- **Chapter 4 (cost analysis)** includes a study to evaluate the current and future cost of biomethane and bio-LNG as a marine fuel, based on available literature data and by using a cost model for bio-LNG from anaerobic digestion and thermal gasification of biomass feedstock;

- **Chapter 5 (lifecycle emissions)** shows the uncertainties regarding the assessment of the overall GHG emissions of bio-LNG in its lifecycle, from production to onboard use, and presents a lifecycle analysis (LCA) model based on SimaPro software to assess the emissions reduction related to the use of bio-LNG from several sources;
- **Chapter 6 (logistics)** illustrates the main logistic issues related to the production and transport of bio-LNG, thus highlighting the barriers that need to be overcome to make this fuel accessible at a reasonable cost at ports around the world;
- **Chapter 7 (adoption assessment)** aims to understand how bio-LNG compares with e-LNG and other alternative fuels in terms of cost and GHG emissions. A forecast model for the future world fleet energy demand for fuel and related CO_2 emissions is first presented, a cost/emissions comparison is then shown to put the performance of bio-LNG in a broader context, and lastly, the future adoption of bio-LNG and other alternative fuels is evaluated.
- **Chapter 8 (fuel landscape)** provides an overview of the current regulatory framework for the use of biofuels, including biomethane and bio-LNG, in shipping, the future trends, the barriers that need to be overcome and the actions required by the stakeholders to foster widespread adoption of this fuel.

The study focuses on the above-mentioned aspects of bio-LNG not only for the current context and especially for the 2030 and 2050 horizons, following the timeline set by IMO emission reduction targets. One of the key aspects that were considered is whether bio-LNG could be considered as a relevant "bridge" fuel together with fossil LNG to meet the medium-term targets, looking at e-LNG as long-term fuel. All the costs in the study are reported in USD (2021).

2. Bio-LNG: liquefied biomethane for shipping

2.1. Production pathways

Bio-LNG (also called liquefied biomethane, or LBM) is derived from the liquefaction of biomethane, a gas that can be produced from the degradation of biomass, either following chemical or thermal process routes. Biomethane is seen as a green alternative to fossil natural gas, and in the future, it will be a key player in the decarbonisation of heat in many sectors, together with hydrogen [4]. However, current production is still limited and can be scaled up significantly. Biomethane is the cheapest renewable gas available today and can provide excellent GHG emission savings [5] across many sectors like power generation, transport (in compressed or liquefied form for heavy-duty road and maritime sectors), high-temperature heat applications in industry and heating and cooking in buildings. It can be produced from biomass and waste following three main routes:

- **Landfill gas recovery**: the decomposition of municipal solid waste (MSW) naturally occurring at landfill sites under anaerobic conditions produces biogas, composed of methane and carbon dioxide, which is captured, cleaned and treated to obtain biomethane.

- **Anaerobic digestion**: crops, biowaste and any other organic material are mixed with water inside airtight containers kept at a constant temperature of around 30-45 °C to allow micro-organisms to break down the organic molecules into methane and carbon dioxide. Then, the biogas can be upgraded to biomethane by removing carbon dioxide through separation processes.

- **Thermal gasification:** lignocellulosic biomass is processed at high temperatures around 700-800 °C by controlling oxygen (or steam) amounts to obtain synthetic gas (or syngas). Syngas is a mixture of different gases, including nitrogen (N_2), carbon dioxide (CO_2), hydrogen (H_2), carbon monoxide (CO) and methane (CH_4). The syngas is then cleaned from contaminants and passed through a methanation step to maximise methane content before the CO_2 removal step.

Biomethane can be transported by pipeline and subsequently liquefied to get bio-LNG, or first liquefied and then transported by truck or ship to the bunkering hub for onboard usage.

2.1.1. Biomethane from landfill gas

Landfill gas recovery is by far the cheapest pathway to get biomethane, which can be produced at a very competitive cost of around 3 $/GJ, in the same range as fossil natural gas. Currently, most of the bio-LNG is produced from landfill gas. However, the production is very limited [6]. This production method suffers from a major issue: it is based on an unreliable feedstock source for future large-scale production and use of biomethane. Landfilling is indeed widely regarded as an unsustainable practice from an environmental and waste management point of view, as, in the future, increasing recycling practices and waste-to-energy facilities will eventually replace landfills. The availability of landfill gas decreases as the organic waste fraction of municipal solid waste is collected separately and used for other purposes (i.e. composting or biofuel generation). For example, the potential of producing biomethane from landfill gas in Europe is quite low due to waste management regulations that limit the available organic fraction that goes into landfills [7]. For this reason, the landfill gas production pathway was not covered by this study.

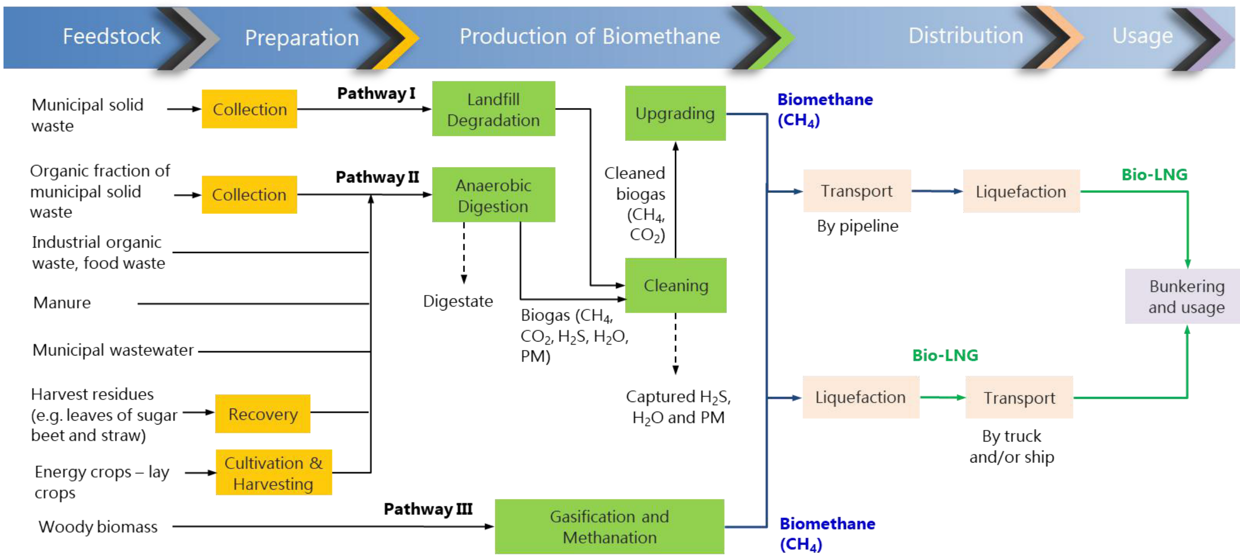


Figure 2.1 – Production pathways for bio-LNG as shipping fuel

2.1.2. Biomethane from anaerobic digestion (biogas upgrading)

The production of biomethane from anaerobic digestion (AD) of biomass consists of two main steps:

- Anaerobic digestion of biomass
- Biogas upgrading to separate methane from other gases

Anaerobic digestion is a biological process that produces biogas from a variety of biomass feedstock (manure, food waste, agricultural waste and others). Typically, biomass used in this process has a high humidity content (>65%) and is kept inside large containers (digesters) in which it decomposes in the absence of oxygen and controlled conditions of temperature and pH. What is left after the decomposition is biogas, a mixture of methane (55-65%), carbon dioxide (35-40%) and trace gases (H_2O, H_2S, N_2, O_2 and other) [8], and digestate, a nutrient-rich substance that can be used as a fertiliser.

The biogas is then upgraded to biomethane by removing CO_2 and trace gases through a two-step process. First, methane content is increased up to 95-97% with physical and chemical technologies such as membrane separation, water scrubbing, chemical absorption and pressure swing adsorption. Some of the methane escapes the process, typically 0.04-0.1% for chemical adsorption and 1-2% for the other technologies. The obtained biomethane purity is around 98-99% [9-10]. The remaining CO_2 from the upgrading process can be used for industrial or agricultural purposes or combined with hydrogen to produce additional methane.

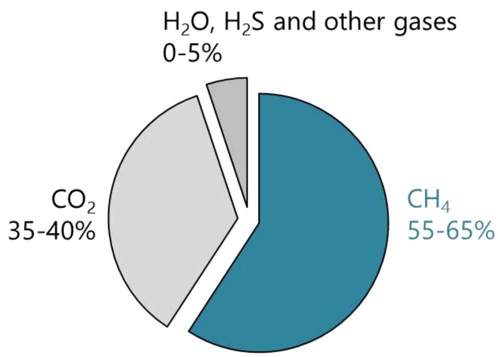


Figure 2.2 – Typical biogas composition

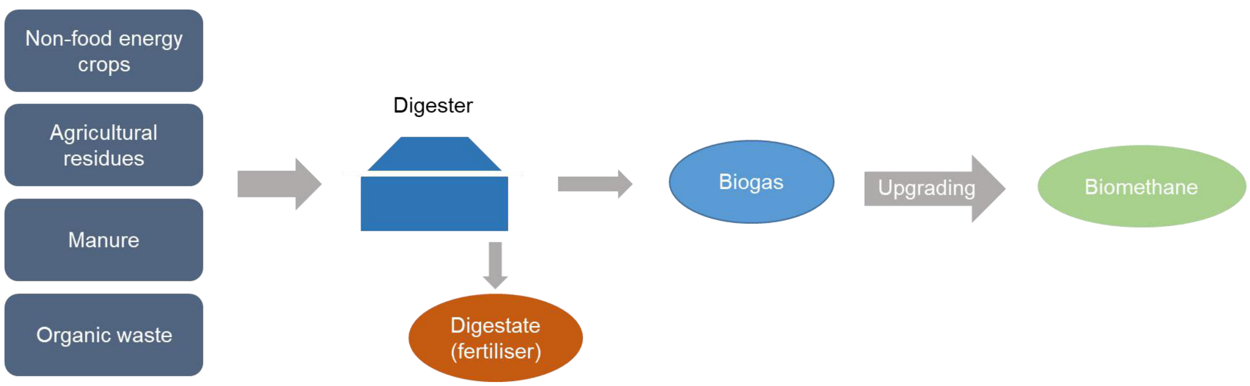


Figure 2.3 – Schematic overview of anaerobic digestion process for biomethane production

Anaerobic digestion and biogas upgrading are mature technologies with well-established practices. Most of the biogas produced today comes from small-scale decentralised plants. Centralised systems can be categorized by the hourly output flow rate: small (50-100 m^3/h), medium (250-500 m^3/h) and large scale (>750 m^3/h). Some very large-scale plants reach a production of thousands of cubic meters of biogas per hour [11], collecting biomass feedstock from hundreds of farms. Large-scale biogas production requires well-organised collection systems to provide the digesters with a constant flow of biomass, and most plants today burn the biogas for power and heat production. When biogas is upgraded into biomethane, it can be injected directly into the gas grid.

2.1.3. Biomethane from thermal gasification

Thermal gasification is a process that involves the reaction of carbonaceous feedstock material at high temperatures and with a controlled amount of oxidising agent (oxygen and/or steam), without combustion, to produce synthetic gas that can be processed to obtain biofuels. Syngas is mostly formed by hydrogen and carbon monoxide, with smaller amounts of CO_2 and methane and needs cooling and cleaning from ash and gaseous contaminants like sulphur and chlorides to be further processed. This technology was originally used to gasify coal. However, more recently, the thermal gasification of biomass has gained interest due to the growing environmental concerns about the use of fossil fuels. Dry lignocellulosic biomass is the most suitable type of biomass feedstock for gasification, and it requires a pretreatment that involves drying and chipping to get small size particles which are suitable for the process. Once the syngas has been cleaned, the methane content can be increased through a methanation reaction step, and after residual removal of water and carbon dioxide, biomethane is obtained.

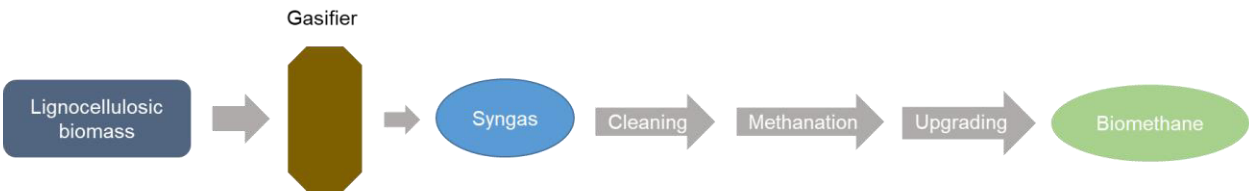


Figure 2.4 - Schematic overview of biomass gasification for biomethane production

Thermal gasification of biomass is a technology still in development and not yet commercially available. This technology has been tested in various demonstration plants with a capacity of up to 20 MW_{th} (on an LHV input basis. Some large-scale biomass gasification projects for power production reach 140 MWth (equivalent to more than 50,000 tons of methane per year). Production of synthetic natural gas and other fuels is still at the demonstration stage (TRL 6-7), and many projects were closed due to the lack of incentives and proper economic returns as the technology is not competitive with the gasification of fossil feedstock. However, the potential for cost reduction is high, and the technology may become competitive in the next decades [12]. Currently, less than 100 biomass gasifiers are in operation globally, but only a few produce biomethane. The largest biomass-to-biomethane plant (GoBiGas) was built in Sweden in 2013, and it demonstrated the technical feasibility of the production of biomethane from the gasification of biomass. However, the project was terminated after a few years due to the lack of investors' confidence caused by the high costs of production, outcompeted by anaerobic digestion technology [13]. If cost reduction occurs, in the future, large-scale plants around 200 MW_{th} size could be built, but they will require a proper assessment of biomass supply chains to ensure operational and financial feasibility [4]. Until 2040-2050, anaerobic digestion is expected to be the dominant technology for the production of biomethane [13].

2.2. Biogas and biomethane production worldwide

Biogas production worldwide is increasing, with Europe being by far the largest producer. Currently, most of the biogas is used as input to produce electricity and heat, while only around 10% is upgraded to biomethane, which is used as a substitute for natural gas for power and heat production or as fuel for transport. Most of the biogas is currently produced from anaerobic digestion plants, and only a small fraction is produced from gasification, most of which is in Europe [7]. Even though the feedstock to produce biogas is available in all regions of the world, the production and use of biogas happen mostly in places where favourable policies exist. Europe, the United States and China cover more than 90% of global production [7]. Most of the European biogas is produced in Germany, mostly from energy crops but also from agricultural residues and manure. Landfill gas recovery is the predominant production method in the US, while China's policies focus on small-scale household digesters, which produce around 70% of the biogas in the country today. Even though the predominant use of biogas today is for power generation, the relatively high cost of the electricity produced in this way compared to solar and wind energy may lead producers to find alternative uses for biogas. One of the most interesting options is to upgrade biogas into biomethane, which is a high-value product that can help decarbonise several sectors.

As shown in Figure 2.6, worldwide biomethane production capacity has been increasing in the last few years, mostly led by Europe and North America. However, this growth trend is likely not sufficient to meet the future global demand to meet climate goals. Together with hydrogen, biomethane and synthetic methane (from hydrogen and CO_2) will be the most important gaseous fuels of the future. According to IEA, following a global pathway towards a zero-emission world, the demand for biomethane will increase drastically and about 8 to 27 times by 2030 and 2050, respectively, compared to 2020 levels [14]. While the biomethane industry is currently small, the potential for significant growth in the future is high. Today the production amounts to almost 5 billion cubic meters per year, generated by about 1000 plants around the world, which is around 0.1% compared to the global demand for natural gas.

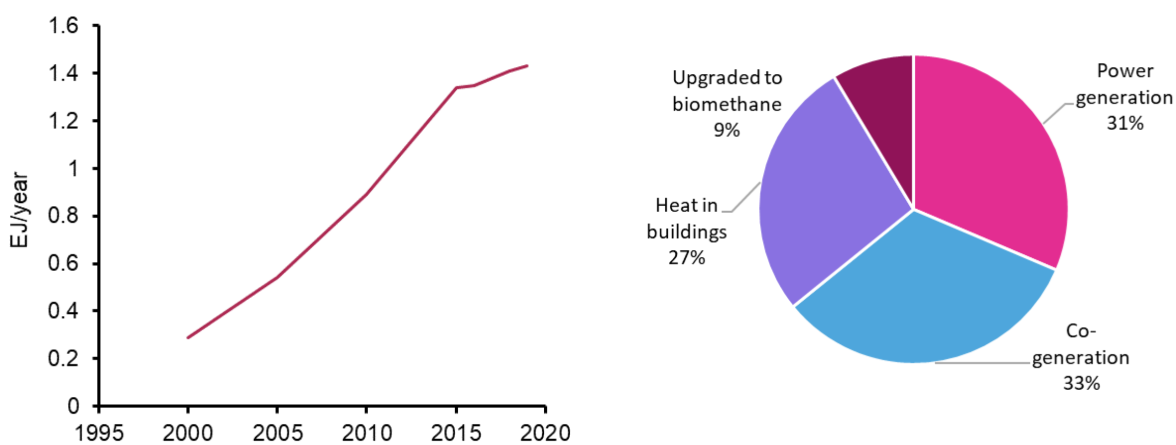


Figure 2.5 – Trend of biogas production worldwide (left) and biogas end uses in 2018 (right). Data sources: [7,15].

Most of the biomethane is injected into the gas grid (60%), a smaller fraction is used as transport fuel (20%), and the rest is used locally for cooking and other applications [7]. A few plants worldwide directly produce liquefied biomethane (see Table 2.1), and most of the production volume currently comes from large-scale plants based on landfill gas recovery in the US. Local production and liquefaction of biomethane still occur at a relatively small scale (3-30 tons/day). However, some new large-scale plants are expected to enter into operation in the next years, with a production capacity of more than 100 tons per day of liquefied biomethane. A few trials of bio-LNG bunkering for shipping were also recently performed by CMA CGM Group and Shell in Rotterdam port [16] and by Furetank and Titan LNG in Amsterdam port [17]. The ships were fuelled with a blend of bio-LNG and fossil LNG (approximately 10% bio-LNG), thus demonstrating the feasibility of bio-LNG as a marine fuel.

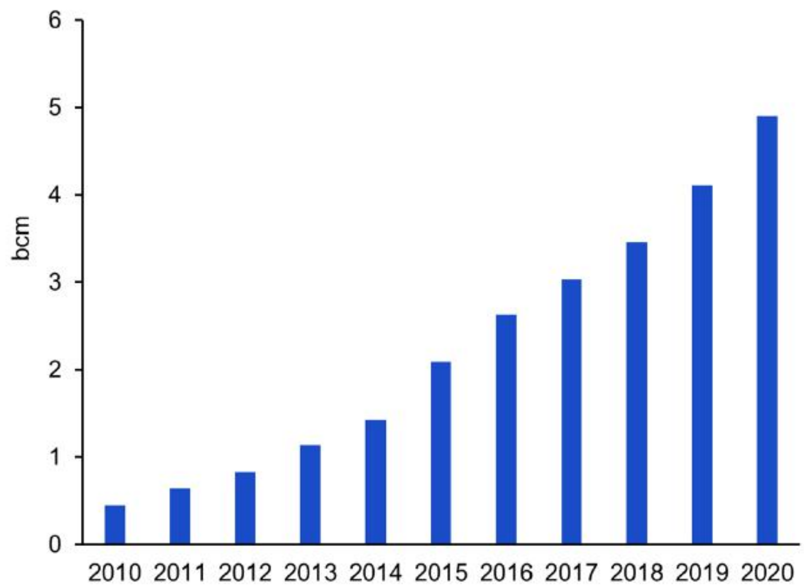


Figure 2.6 – Global biomethane production capacity in billion cubic meters. Data source: [18].

Table 2.1 – List of existing and planned bio-LNG production plants

Company	Country	Biomass source	Annual production (tons/year)
Hamworthy/Wartsila	Norway	waste	3600
Hamworthy/Wartsila	Norway	waste	3300
Biokraft/Wartsila	Norway	fishery waste, paper mill slurry	9100
Gasum	Finland	biowaste	4300
Air Liquide	Sweden	waste	4900
Air Liquide	Italy	agri-residues, manure	3100
Air Liquide	Italy	agri-residues, manure	3200
CIB	Italy	agri-residues, manure	2000
Cryo Pur	Ireland	agri-residues	1100
Gasrec	UK	landfill gas	6000
Gasrec	UK	landfill gas	5000
Linde	US	landfill gas	7200
Linde	US	landfill gas	10000
Titan, Attero, Nordsol (planned)	Netherlands	-	2400
MAKEEN Energy (planned)	Denmark	-	20000
REEFUELERY (planned)	Germany	agricultural waste	63000

3. Biomass feedstock availability

One of the key challenges of supporting the shipping industry with biofuels such as bio-LNG is to assess whether there will be enough biomass available to produce fuels for the maritime sector. Biomass is indeed one of the key energy sources for the future. However, a few problems, such as sustainability issues and resource limitations, may impair its availability. In this section, an estimation of the future potential availability of bio-LNG for the shipping sector is presented, starting from the most suitable types of biomass that can be used to produce biomethane and ending with future estimates of the contribution that bio-LNG could provide to the maritime sector in relation to the overall future energy demand for shipping fuels.

3.1. Feedstock types

Biomass is any renewable organic material that comes from plants and animals. This important resource can be used to produce materials such as paper, or it can be converted to useful energy in the form of heat, electricity or biofuels such as biodiesel and biomethane. A wide variety of feedstocks can be used to produce biogas, biomethane and ultimately bio-LNG. Typically, four main types of biomass feedstock categories are defined based on so-called "generations" for biodiesel production, as shown in Table 3.1. First-generation feedstock includes edible oils such as sunflower oil, soybean oil, rapeseed oil, palm oil and coconut oil. Through a chemical process called esterification, it is possible to obtain biodiesel that can be used in existing marine engines with minor modifications.

Table 3.1 – Biomass feedstock types for biofuel production

Generation	Feedstock type	Conversion technology	Pros	Cons
1st	Food crops and edible oils	Esterification and transesterification of oils	Low cost	Competition with food supply
2nd	Non-edible oil seeds, energy crops grown on surplus land, lignocellulosic biomass, agricultural residues, forest residues	Fermentation or thermochemical process	Avoid competition with food Use of non-arable land Use of waste streams	Higher cost compared to first-gen biofuels Land-use change emissions
3rd	Algae	Algae cultivation, harvesting, oil extraction, transesterification, or fermentation, or thermochemical process	No agricultural land use High growth rate	Early stage technology High cost Need large areas with specific requirements Ecological risks of large-scale cultivation
4th	Genetically modified algae and microbes	Genetically engineered feedstock, same process as 3rd generation	High yield and production rate High CO_2 capture	Very high cost Technology research at a very early stage

Although the vast majority of the biodiesel produced today comes from 1st-generation feedstocks [19], land use and biodiversity loss are critical problems: for this reason, any biomass derived from waste streams of other existing processes which does not compete with food supply is considered the most sustainable feedstock for biofuel production in the long term [20]. Non-edible oil seeds, energy crops such as Myschantus or Alphalpha that grow on surplus and non-arable lands and waste from agricultural processes and animal farming are the most interesting biomass sources for the future production of biofuels for the transport sector due to their sustainability. It is also possible to obtain advanced biofuels through processing aquatic biomass (algae) cultivated at sea. Although this looks a promising way to produce fuels without impacting agricultural land, the technology to convert such feedstock into useful products is still at the development stage, and many uncertainties related to the impact of massive cultivation of seaweed in coastal areas make this pathway unlikely to provide a large scale supply in the next decades [21].

In this perspective, biogas and biomethane future production will rely more and more on dedicated energy crops and waste biomass [22]. Four main categories of sustainable biomass feedstock for biomethane are defined as follows:

- **Energy crops**: high yield potential and low maintenance crops such as Miscanthus and switchgrass that can be grown on dedicated surplus non-arable land or as part of existing rotational cropping in a way that does not interfere with food production.
- **Agricultural residues**: stalks, husks, leaves and roots of food plants (typical cereals such as rice, maize and wheat), leftovers of harvesting and processing food crops.
- **Manure, sludge and organic waste**: waste from intensive animal farming, usually applied as fertiliser on agricultural soil or food and sewage waste from highly populated areas (cities).
- **Forestry and wood waste:** forest residues such as leaves, barks, pieces of the trunk, and branches and wood waste from processing industries like sawmills, plywood, panels, and other wood products supplies.

The main challenge related to the use of such biomass feedstock for the production of biogas (which can be upgraded to biomethane and bio-LNG) is due to the collection of waste material and transport to the biogas plant, which is not always convenient from an economical and logistical point of view.

3.1.1. Energy crops

Energy crops are defined as crops grown with the purpose of producing energy. They include edible crops used for energy production (cereal crop silage and oilseeds) and non-edible crops (grasses and other plants). Since edible plants fall into the 1st-generation biomass feedstock category because of their competition with food uses, they are not generally considered sustainable sources of biomass for the future. For this reason, in this study, it is referred to as energy crops, only the non-edible plants that can be harvested and converted into energy and biofuels.

Energy crops are great sources of biomass to produce biomethane. However, they require land to be grown upon, and if this land could be used to grow food, a problem of food availability may arise as the unrestrained cultivation of energy crops can lead to shortages and price increases of food. The solution could be to cultivate these crops on land that is currently not used for agricultural uses. However, this poses another problem related to land use change. Indeed, any land used for cultivation is withdrawn from other kinds of ecosystems, such as forest, peatland, grassland, and the spread of energy crop fields poses a serious threat to biodiversity and soil fertility and causes GHG emissions due to the altered carbon cycle of the soil. This phenomenon may even neutralise the benefits of using biomass as a source of clean energy. Another important consideration is related to the fact that growing crops require water and fertilisers, leading to an increase in resource consumption and CO_2 emissions.

For all these reasons, it is considered sustainable only the energy crop that is grown following strict sustainable agricultural practices:

- **Rotational cropping**: different crops are grown on the same land in rotation.
- **Double cropping**: harvesting is performed twice a year.
- **Cover cropping**: crops are grown when land would normally be left uncultivated between two subsequent harvests.
- **Intercropping**: cultivation of two different crops in the same area during the same season (i.e. by planting the crops in alternate rows)

3.1.2. Agricultural residues

The parts of food plants that are not edible are regarded as crop residues. Stalks, leaves, roots and husks of common cereal and other food plants are part of a waste stream from the agricultural industry that represents a huge potential biomass source for the production of biofuels which is in most cases not exploited. Usually, these residues are left on land for fertilisation purposes, fed to livestock or burned. However, a fraction of such residues can be harvested and used for energy purposes. It is estimated that up to 50% of crop residue can be sustainably recovered without impairing soil properties and without subtracting biomass from other sustainable farm practices [22]. Common residues that can be used for biofuel production come from rice, maize, rye, wheat, barley, oats, rapeseed, sugar beets, sugarcane, and sorghum which are cultivated all around the globe and are therefore available almost everywhere. Agricultural residues represent a huge unleashed potential and one of the most promising future sources of biomass for energy purposes.

3.1.3. Manure, sewage sludge and organic waste

The current global livestock includes 1.5 billion cattle, 1 billion pigs, 22 billion chickens and 0.2 billion buffaloes [22]. Animal farming produces an enormous amount of manure every year that can be collected for several purposes. Under current management practices, manure is stored in ponds and subsequently applied to agricultural land as fertiliser. Even though this may seem an efficient way of using waste from animal farming, this practice causes several drawbacks: the decomposition of manure in storage ponds or on the fields causes the emission of methane into the atmosphere, thus contributing in a significant way to global warming (CH_4 is a powerful greenhouse gas). Nitrous oxides are also emitted, and nitrates can contaminate shallow waters. The amount of emissions from manure depends on many factors, including management practices, soil characteristics and animal diet. If manure is instead collected to be digested in anaerobic digestion plants, greenhouse gas emissions are significantly reduced. Moreover, the leftover digestate can be used as fertiliser to totally or partially replace the application of the digested manure. It is estimated that if all the manure produced by cattle, pigs and chickens around the world was collected and processed through anaerobic digestion, around 250-370 billion m^3 of biomethane could be produced [22], which is equal to 6-9% of the global demand for natural gas in 2021 [23]. However, it is important to note that this source of biomass is slightly less reliable compared to agricultural residues and energy crops, as it is mostly based on intensive farming and depends on food habits that may change in the future due to increasing environmental and ethical concerns related to the use of meat.

Sewage sludge from cities and populated urban areas in developing countries where proper treatment is absent could be recovered and used to generate biomethane. However, the potential is very low compared to other sources discussed here. Therefore, it was not considered in this study. Food waste from cities may also be an interesting source of biomass for biomethane production for specific local applications, but its potential is lower compared to energy crops, agricultural residues and manure.

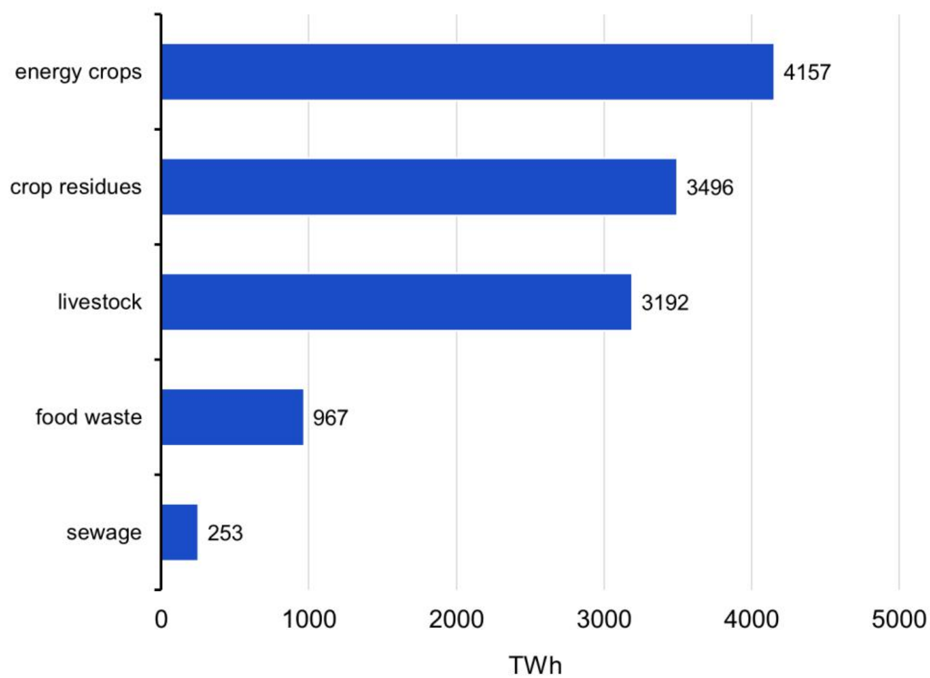


Figure 3.1 – Potential energy generation from various biomass feedstocks through anaerobic digestion and biogas power generation in TWh. Energy crops, agricultural residues and manure account for 90% of the total energy potential of biomass through anaerobic digestion. Data source: [22].

3.1.4. Forestry and wood waste

Forestry activities leave behind several residues that can be collected, including primary residues (treetops, stumps, branches), which are leftovers of wood harvesting and secondary residues, or wood waste (sawdust, bark) that are produced during wood processing. Even though a fraction of primary residues must be left on site for ecological benefits and wood waste is, in some cases, already used for local energy purposes (i.e. pellet production), there is still a large unexploited potential behind this biomass source that can be used for biofuel production. Woody biomass is suitable for the gasification process due to the lower water content compared to other types of biomass feedstock previously discussed.

3.2. Global availability

There are several studies in the literature that tried to estimate the global potential of biomass for energy use, and their results differ widely. This is due to the fact that estimating the potential for biomass energy use worldwide is a complex task that requires several assumptions based on technical, environmental and economic criteria. The most common concepts for the evaluation of global bioenergy potential are [24]:

- **Theoretical potential:** calculated assuming that all net primary productivity of biomass produced on the total surface of the earth not used for food production could be available for bioenergy purposes.
- **Technical/geographical potential:** takes into account the part of the theoretical potential bonded by topographic and technological constraints and by future demand of land for food and other non-energy purposes.
- **Sustainable potential:** the fraction of the technical bioenergy potential that can be exploited by fulfilling sustainability requirements such as conserving ecology, biodiversity, soil and water quality.
- **Economic/realistic potential:** takes into account supply-demand curve projections, market development constraints and negative social impacts.

The use of biomass for energy purposes is linked to increasing concerns regarding environmental impacts such as land use change and related GHG emissions, biodiversity loss, social inequalities, water eutrophication and withdrawal. For this reason, the sustainable biomass energy potential represents a more accurate depiction of the amount of biomass that could be available in the future for energy uses such as biofuel production. Bioenergy use in the world accounts for around 10% of primary energy demand today, mostly for traditional uses such as cooking and space heating. However, more advanced biomass uses for the production of electricity and biofuels will likely increase in the future [7,25].

An overview of the global biomass energy potential by feedstock type in 2030 and 2050 are reported in Table 3.2 and Table 3.3. The most recent studies typically show more conservative estimates due to more stringent sustainability constraints and resource limitations with better data availability [26]. Most forecasts for 2030 suggest a potential of 120-150 EJ per year coming from biomass, more than double the biomass primary energy supply in 2020.

However, a recent roadmap document from International Energy Agency [14] describes a development scenario with lower energy consumption that could lead to reaching the target of net zero emissions by 2050. Under the scenario, biomass supply in 2030 will only reach half of the potential calculated in other studies. For what concerns 2050 forecasts, the biomass energy potential varies greatly depending on the study, which considers different scenarios and assumptions on world population and economic growth, the productivity of agriculture and livestock, and the availability of surplus lands for energy crop production. Older studies give estimates for the global biomass energy potential in 2050, which are almost three times higher compared to more recent and accurate studies (see Figure 3.2).

Table 3.2 – Selected literature overview of global sustainable biomass energy potential in 2030 (EJ/y)

<table>
<tr><th>Feedstock type</th><th>Krewitt et al. 2009</th><th>Kopetz 2013</th><th>IRENA 2014</th><th>IEA 2021</th></tr>
<tr><td>Energy crops</td><td>68</td><td>23</td><td>36</td><td>18</td></tr>
<tr><td>Agricultural residues and waste</td><td rowspan="2">62</td><td>38</td><td>52</td><td>32</td></tr>
<tr><td>Forestry residues</td><td>92</td><td>35</td><td>22</td></tr>
<tr><td>Total (EJ/y)</td><td>130</td><td>153</td><td>122</td><td>72</td></tr>
</table>

Table 3.3 – Selected literature overview of global sustainable biomass energy potential in 2050 (EJ/y)

<table>
<tr><th>Feedstock type</th><th>Haberl et al. 2010</th><th>Dornburg et al. 2010</th><th>IPCC 2012</th><th>Searle and Malins 2015</th><th>Daioglou et al. 2019</th><th>Kalt et al 2020</th><th>IEA 2021</th><th>ETC 2021</th></tr>
<tr><td>Energy crops</td><td>89</td><td>155</td><td>155</td><td>82</td><td>69</td><td>48</td><td>39</td><td>9</td></tr>
<tr><td>Agricultural residues and waste</td><td>100</td><td rowspan="2">105</td><td>100</td><td>3</td><td rowspan="2">84</td><td>31</td><td>44</td><td>20</td></tr>
<tr><td>Forestry residues</td><td>27</td><td>80</td><td>3</td><td></td><td>20</td><td>39</td></tr>
<tr><td>Total (EJ/y)</td><td>216</td><td>260</td><td>335</td><td>88</td><td>153</td><td>78</td><td>102</td><td>67</td></tr>
</table>

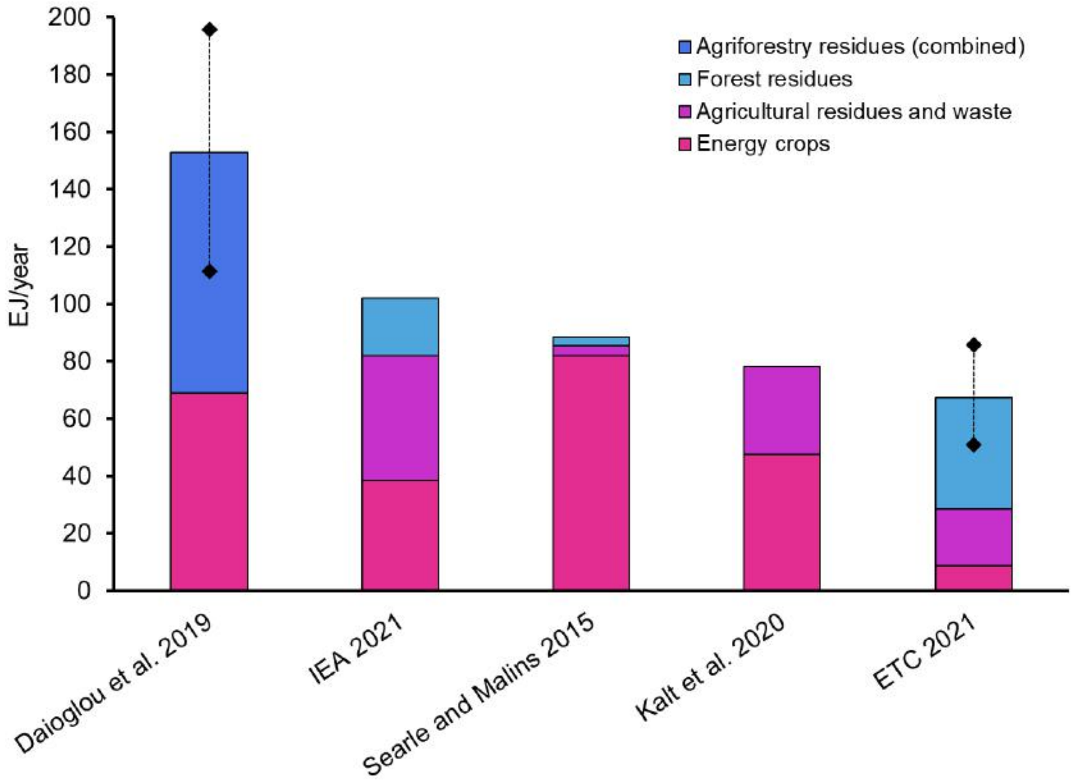


Figure 3.2 – Sustainable biomass energy potential in 2050 from selected recent studies.
Data sources: [14,27-30].

3.3. Geographical availability

Due to the nature of the energy source, biomass is not equally available all over the world regions. Indeed, different areas may provide different types and amounts of biomass feedstock depending on the local climatic and geographical environment, as well as economic and social conditions. Biomass energy potential is concentrated in North America, South America and Asia (mainly China, India and Central Asia). Waste and residual products from the agricultural activity are concentrated mostly in South America (sugarcane and soybean), East Asia, South-Eastern Asia and Indian Subcontinent (rice and soybean), and North America (maize and soybean), as shown in Figure 3.3.

Energy crops and residues from forest management dominate in North America and Europe, respectively. Energy crops and derived residues are instead abundant in South America, while in Asia, there is a huge potential deriving from agricultural residues. The availability of biomass for energy uses is expected to grow significantly in the next decades, especially in Asia and South America, which may become interesting areas for the production of cheap biomethane (see Figure 3.4). This may lead to a lower price for bio-LNG from Asian and South American areas compared to Europe and US.

Figure 3.3 – Geographical distribution of agricultural residue potential from common food crops. Data source: [31].

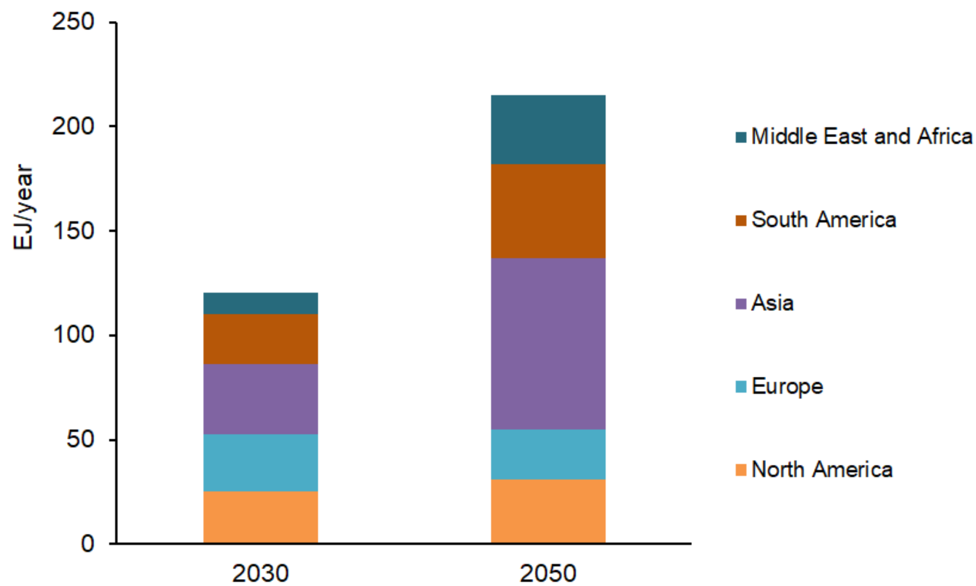


Figure 3.4 – Biomass energy potential in 2030 and 2050, by world region. Data sources: [26,32].

3.4. Competing uses of biomass

As reported by a 2021 document from Energy Transitions Commission, the global demand for biomass is expected to rise over time due to different sectors of human activity, and this will likely increase the price of feedstock due to the limited availability of this resource [30]. As biomass becomes more and more expensive, other decarbonisation options may be preferable by different sectors, while some uses of biomass will become of high priority due to the lack of alternatives. Future demand for biomass from various economic sectors (transport, space heating, chemical industry, power and industrial heat generation) most likely will exceed global supply capabilities, and therefore biomass use will be prioritised for some sectors against others. Even considering the most conservative scenarios, at least 17–19 EJ of biomass would be required for energy and materials by 2050, a value more than 70% higher compared to today's demand of 10 EJ (other scenarios show an increase of 150%).

The use of bioenergy with carbon capture and storage (BECCS) may also become competitive in large-scale industries, such as pulp production, waste incineration, and biofuel production plants. The CO_2 sequestered from biomass could also be used as feedstock to produce synthetic fuels in the long term. Material uses of biomass are the highest priority sector, as the use of biomaterials in the future will increase drastically, and there are no other alternatives in sight. Biomass can indeed be used to produce paper, construction material and furniture, fibres and chemical feedstock for plastics and other materials. Moreover, the use of biomass as materials has the positive effect of temporarily storing carbon, thus helping mitigate the global warming effect. Due to extremely strict volume and weight constraints of the fuels used, the aviation sector immediately follows materials in terms of priority of biomass use in the future. While the adoption of most alternative fuels such as hydrogen, ammonia and e-LNG would require an excessive reduction in space onboard planes due to the low energy density of the fuels, advanced biofuels such as Fischer-Tropsch fuels and bio-kerosene are able to comply with the tight requirements of flight propulsion.

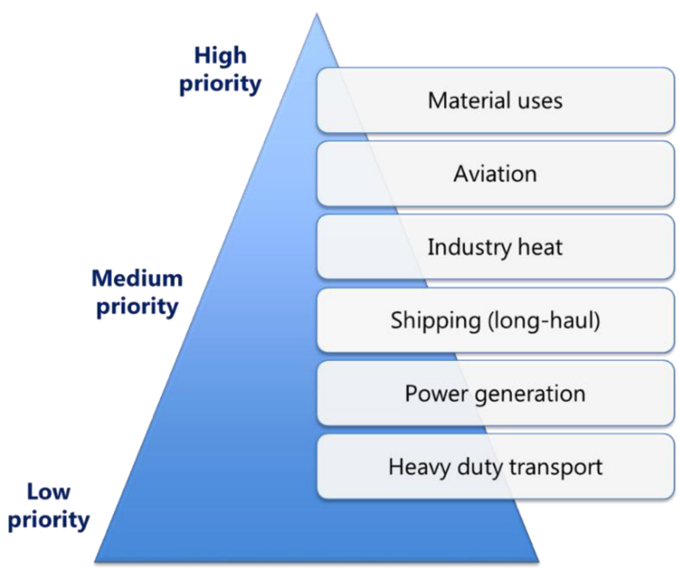


Figure 3.5 – Pyramid of priority rights on future biomass use for different economic sectors. Elaborated from [30].

A few niche applications of high-temperature heat in industries such as cement and steel production may also find biomass as the most economical solution. In terms of biomass use priority in the upcoming decades, the shipping sector comes immediately after material uses, aviation and special application of industrial heat (see Figure 3.5). This means that although there will be intense competition among sectors, a fraction of the global biomass will likely be available to produce biofuels for shipping [30].

3.5. Potential availability for shipping

The amount of liquefied biomethane potentially available for the shipping sector in the future is subject to many uncertainties. First of all, it is unclear how much of the available potential for biomass energy will be realistically available, depending on many variables such as the cost and availability of feedstock and the strength and direction of the decarbonisation policies around the world. Subsequently, the competition among the different uses of biomass will determine the amount of biomethane produced, which will be shared between the transport sector and the power and heat sector. The shipping industry must fight for its own share of biomethane to be liquefied into bio-LNG for use as fuel. Even if it is difficult to make reliable evaluations of the future evolution of the global biomethane market, it is possible to make an estimate of the future potential availability of bio-LNG for the maritime sector based on the most recent analyses and forecasts presented in the previous chapters, following the scheme presented in Figure 3.6. Considering the sustainable potential presented in chapter 3.2, only a fraction of it will be realistically available to the world society, depending on the biomass energy production scale-up and technology development. Even though it is hard to determine how much of the sustainable energy potential from biomass will be actually exploited, some literature sources suggest that considering that only a fraction of the waste biomass can be collected, and with the assumption that a global effort towards the exploitation of biomass resources in a decarbonisation perspective will be put in place, around 40-50% of the global potential could actually be available for use [24]. A fraction of such "realistic" biomass energy available will be converted to biomethane for several end-uses. According to recent energy forecast scenarios from IEA, in order to reach zero emissions by 2050, the share of biomethane production over the total biomass energy supply will experience a steep increase from today's value to 3% and 8% in 2030 and 2050, respectively, also thanks to the establishment of blending mandates for the gas networks [14].

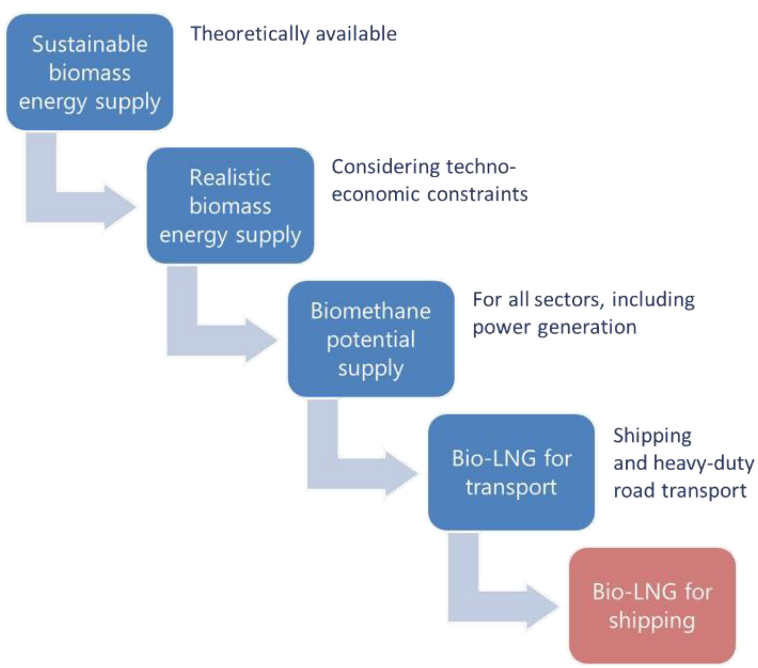


Figure 3.6 – Conceptual scheme for evaluating bio-LNG availability for the shipping sector

Many sources state that the biomethane role as a transport fuel will likely become very important for the decarbonisation of the transport sector, especially for heavy-duty road transport and shipping. Of all the biomethane that will be produced globally, the share that will go to the transport sector is variable, depending on the competition with hydrogen and its uptake level for power and heat production and on the economic feasibility of BECCS. A recent study from Navigant on the future of renewable gas in Europe considers an ''optimised gas'' scenario for which renewable and low-carbon gas can be used to its full potential [4]. Under such a scenario, hydrogen and biomethane will play a key role in the decarbonisation of several economic sectors, and around half of the total produced biomethane could be liquefied into bio-LNG to be available for the transport sector. A more prudent global estimate of 20% is instead proposed by the IEA roadmap [14]. As an assumption for the current study, a percentage range of 20-50% was therefore set for the final use of biomethane in the transport sector in 2030 and 2050. According to the Navigant study, under optimal renewable gas allocation strategies, shipping could account for up to 80% of the total bio-LNG produced (Figure 3.8). The rest will be used in heavy-duty road transport for long-distance routes where electric batteries are not suitable for trucks due to the low energy density.

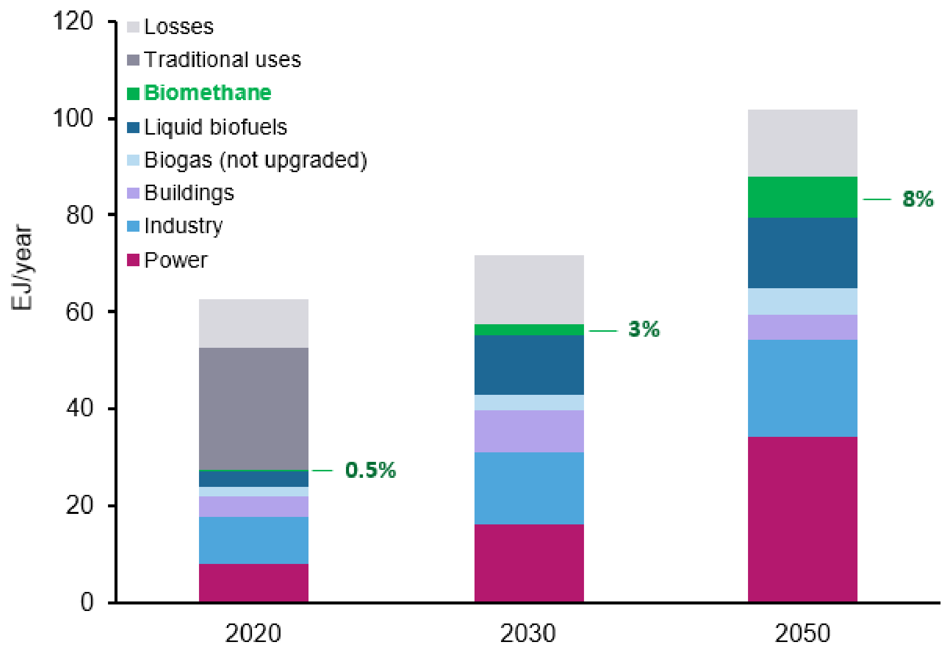


Figure 3.7 – Future uses of biomass energy. Data source: [14].

Following the above-presented assumptions and considering 60% energy efficiency of biomass-to-biomethane conversion [33], a realistic amount of energy from bio-LNG fuel equal to 0.1-0.3 EJ and 0.3-1.5 EJ of bio-LG energy could be available for the shipping sector in 2030 and 2050, respectively. This means that bio-LNG could cover a fraction of 0.4-3.1% in 2030 and 2.4-12.6% in 2050 of the total energy demand for shipping fuels (Figure 3.9). This is valid if the use of pure bio-LNG to fuel ships is assumed. However, when considering it as a drop-in fuel for blending with fossil LNG, the potential energy demand coverage increases. When 20% blending is considered, bio-LNG could cover up to 15.7% and 62.9% of the total energy demand in 2030 and 2050, respectively. The results clearly show that the use of bio-LNG as a bridge fuel together with fossil LNG to meet the medium-term emissions reduction goals could support a relevant part of the world fleet. However, it is important to note that this estimation is subjected to many uncertainties related to the future evolution of the role of biomethane in renewable gas production and demand, which ultimately depends on national and international policies that still need to be issued. The estimated demand coverage potential of bio-LNG is in line with IEA Net-Zero Energy scenarios, for which the demand for biofuels in the maritime sector will be around 7% and 21% in 2030 and 2050, respectively. DNV forecasts instead an adoption rate of 3-4% of shipping biofuels (based on energy demand) in the next decades. Moreover, DNV foresees a strong use of natural gas-based fuels in the future, up to 36-40% of the total energy demand for shipping in 2030 and 2050, respectively. Assuming at least 80% of such demand will be covered by LNG, based on current ships in operation and on order, this means that around 30% of the energy demand will be accounted for fossil LNG. In such a scenario, bio-LNG is entitled to become a viable drop-in biofuel that can be blended with fossil LNG to comply with the IMO targets by 2030 and 2050. Bio-LNG can therefore play an important role in the decarbonisation of the maritime sector and be part of both biofuel and LNG forecasted energy demand for shipping, depending on deployed international policies, market prices and technological advancements in biofuel production and use.

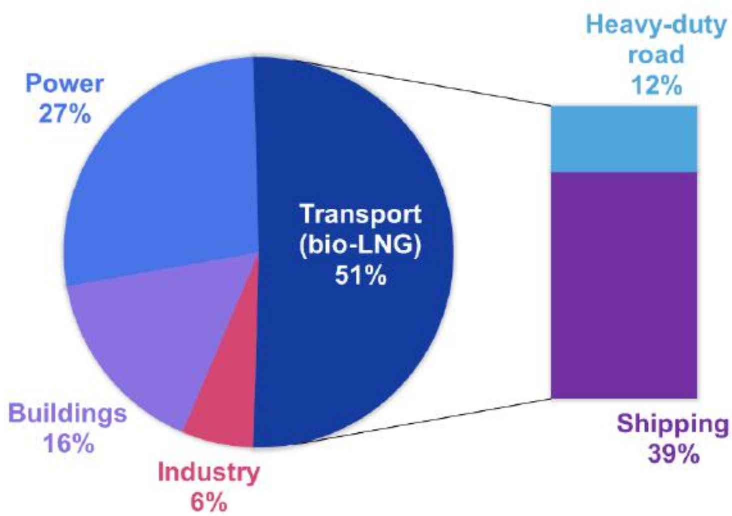


Figure 3.8 - Renewable and low-carbon gas demand share in 2050. Data source: [4].

International Energy Agency released a report to show the necessary actions required by the main sectors of the economy to reach net-zero CO_2 emissions by 2050 [14]. According to this scenario, with sufficient effort and investments by strategic sectors such as the energy and transport sectors, the global temperature rise can be limited to 1.5°C. Under these assumptions, the shipping sector fuel mix will change over time, and gradually the conventional fuels such as fuel oil and LNG will be phased out and replaced by low-carbon alternatives like biofuels and hydrogen-based fuels. This scenario assumes that 7% of shipping energy demand will be covered by biofuels by 2030, and this share will increase to 21% by 2050. Bio-LNG could play a key role in this scenario, and the availability analysis showed that the required biomass to produce biomethane for shipping transport could be available if the global potential is exploited, and other sectors may be driving the adoption due to the future global development of biomethane production and use across different sectors. IEA also forecasts a rapid development of the use of e-ammonia, thanks to its relatively cheap cost, among other synthetic fuels. However, the report fails to note that e-ammonia as a shipping fuel must face several challenges related to safety issues due to its high toxicity, onboard NO_x emissions and an engine and combustion technology that still needs to be proven. This will likely leave room in the market for other synthetic fuels to play a role in the decarbonisation of the sector, and e-LNG may find its share in the "ammonia" demand in the Net-Zero Energy scenario.

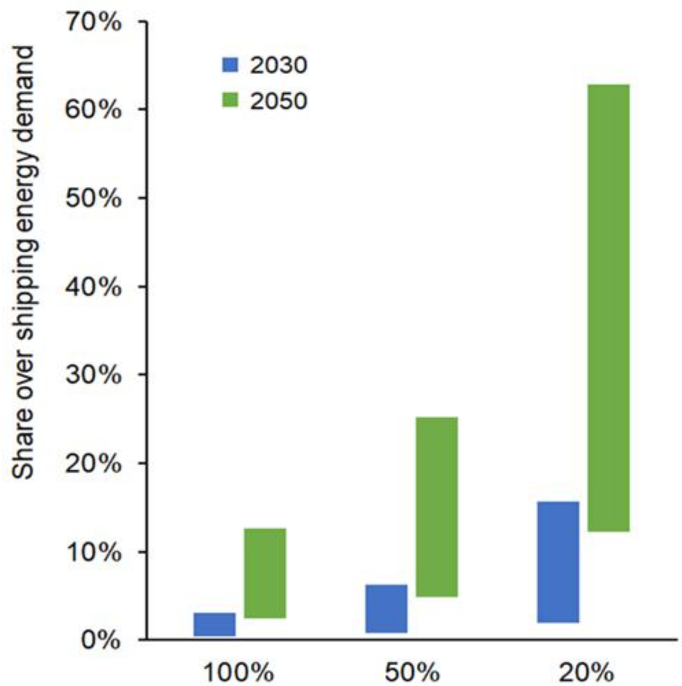


Figure 3.9 – Potential availability of bio-LNG for shipping sector in 2030 and 2050 over total shipping energy demand, for different blending rates with fossil LNG.

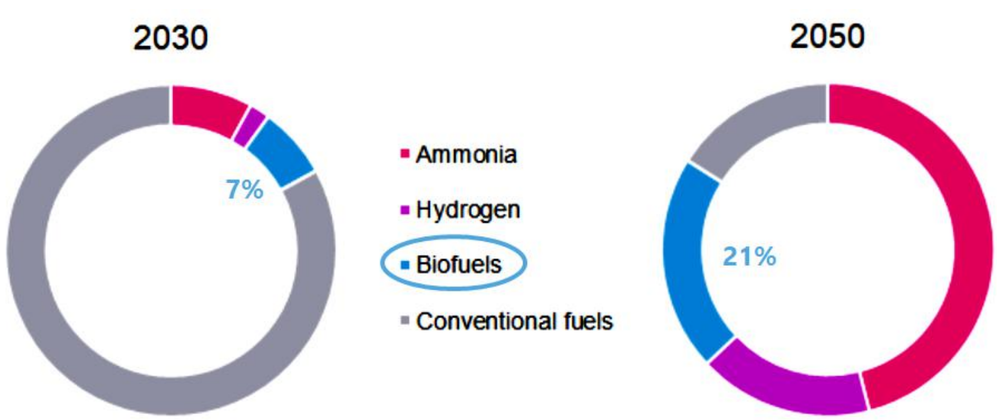


Figure 3.10 – Forecasted fuel mix in shipping. Data source: [14].

4. Cost analysis

The availability of biomass to produce bio-LNG is an important issue. However, the fuel cost is just as important to determine whether this fuel is a potential candidate for future decarbonisation of the shipping sector. The cost of marine fuels is one of the most important factors driving their adoption among many alternatives. It is, therefore, crucial to determine the cost of bio-LNG as bunker fuel, to perform a fair comparison with other promising green fuels such as hydrogen, ammonia or methanol. Following this rationale, in this chapter, a cost analysis of bio-LNG fuel is presented, with an evaluation of current and future costs in 2030 and 2050 based on the maturity of the fuel production technology, production scale-up and future trends of adoption.

4.1. Cost model

The final cost of bio-LNG to the shipowner ultimately depends on the following cost components:

1. Biomass feedstock
2. Production cost of biomethane (biogas production & upgrading)
3. Liquefaction cost
4. Transport cost
5. Bunkering costs and port fees

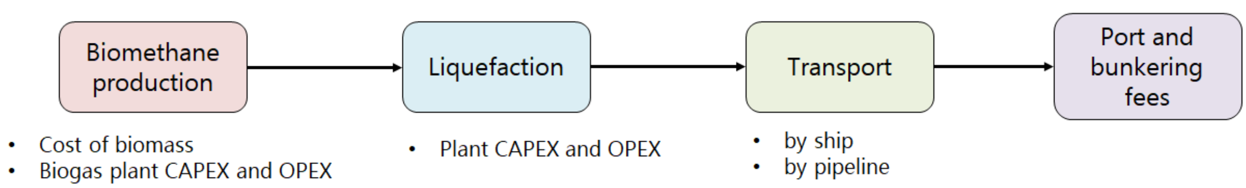


Figure 4.1 – Cost components for the bio-LNG value chain

The first two cost components are the most difficult to assess due to the relative scarcity of data, and therefore these are the ones the analysis was mostly focused on. The costs related to the final part of the value chain, from liquefaction to bunkering, are well-known thanks to the operational experience with fossil LNG as marine fuel globally acquired in the last 15 years.

4.2. Feedstock cost

Biomass is one of the main variable costs that influence the production cost of biomethane and, ultimately, bio-LNG. Feedstock can take up to 10-40% of the overall biomethane cost, and its price is likely to rise in the future due to the increasing demands from several economic sectors that aim to decarbonise their operations [34]. Due to the wide variety of feedstock types and the absence of a global commercial market of biomass (with a few exceptions such as wood chips and pellets [35]), which is usually locally sourced and distributed, it is often hard to define a specific price for this kind of feedstock. Biomethane generated from manure typically has a different cost compared to biomethane from energy crops. The final cost of the delivered waste biomass is mainly due to collection, transport, handling and storage that are needed to deliver the biomass to the plant, while the use of energy crops introduces additional cost factors due to fertilising, watering and harvesting. Although biomass feedstock costs may vary depending on local conditions, it is possible to define some typical ranges based on the available literature, as shown in Figure 4.2.

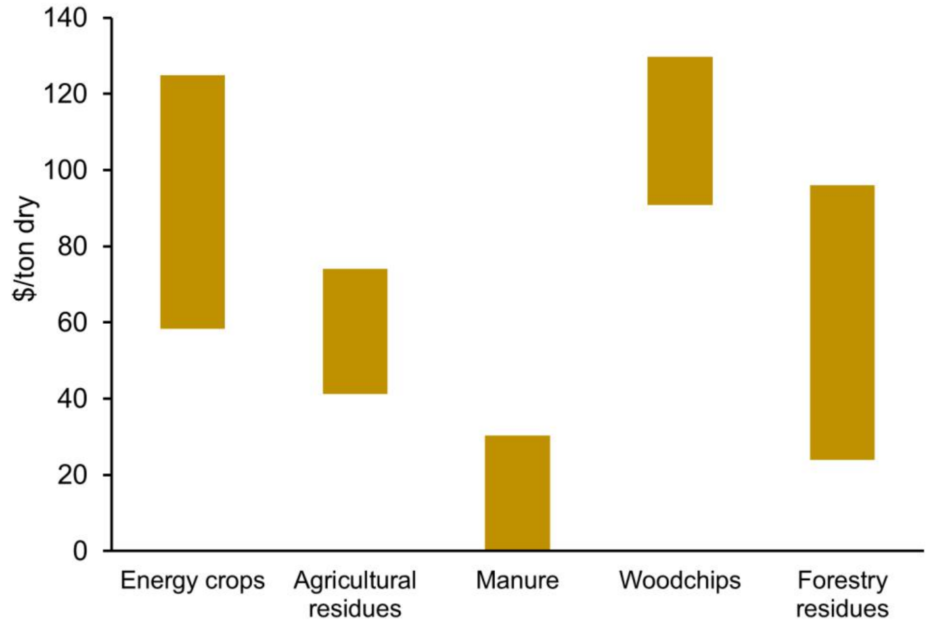


Figure 4.2 – Range of biomass cost by feedstock type. Data sources: [4,34-39].

The lowest feedstock cost is typically manure, which can generally be collected at a low cost from animal farms. Manure has a high nutrient content, and therefore it is generally used as fertiliser. Instead, if it is used as feedstock for biofuel production, it may be needed to replace with industrial fertilisers, and this increases the costs. A common cost value assigned to manure is 10-20 $/ton of dry matter. Agricultural and forestry residues are more expensive due to the extra cost of collecting and harvesting on the field, and a ton of dry matter costs 60-70 $ on average. Energy crops and woodchips are the most expensive kind of feedstock, and they can cost up to 100 $/ton dry and even more.

4.3. Biomethane production cost

The cost of producing biomethane depends on the processing technology used to convert biomass into methane. Biomethane from anaerobic digestion is typically cheaper due to the relatively simple process, while gasification requires more complex plant and management, thus increasing the production costs.

The scale of production also is an important factor that drives down the final cost of the fuel. The cost of biomethane can be estimated by considering its different components: i) investment cost for the processing plant (CAPEX); ii) expenses for maintenance and operating costs (OPEX); iii) feedstock cost. A life cycle cost model was built based on available literature data in order to assess the cost of biomethane with different assumptions regarding fuel production technology, plant size and feedstock cost.

4.3.1. Feedstock yield

The amount of feedstock input required to produce biomethane that can be liquefied to bio-LNG depends on the methane yield, defined as the amount of methane that can be generated by processing one ton of biomass matter. The yield ultimately depends on feedstock type and on the technology used to convert it into methane (namely, anaerobic digestion or thermal gasification). However, feedstock is the major factor governing the amount of biogas and biomethane production, and it also determines the retention time of the production process. The key parameters involving methane production are:

- Dry matter (DM) content, representing the solid fraction in the feedstock.
- Volatile solids (VS), representing the amount of organic fraction of total solid within the feedstock
- Methane yield, generally used for farm waste, energy crop, sewage sludge, etc., expressed in the unit of m^3CH_4/ton DM or m^3CH_4/ton VS

The volatile solid refers to a substance that can easily transform from its solid phase to its vapour phase without going through a liquid phase and can be seen as a measure of the energy left in the feedstock. A literature review was conducted to assess the methane yield from the processing of different biomass feedstocks through anaerobic digestion and thermal gasification. The aggregated results are reported in Table 4.1.

Table 4.1 – Methane yield ranges for different biomass feedstocks and conversion technologies. Data sources: [33-34,40-47].

Biomass type	**Processing technology**	**Methane yield (m^3CH_4/tonDM)**
Manure	Anaerobic digestion	218-293
Agri- and food waste	Anaerobic digestion	225-300
Crops	Anaerobic digestion	237-387
Woody biomass	Thermal gasification	140-361

4.3.2. Biomethane from anaerobic digestion (AD)

The AD processing plant consists of the anaerobic digester, where the biomass is fed to fermentate and generate biogas, and the cleaning and upgrading section, which can be based on several different technologies that remove contaminants from the biogas and allow to separate the methane from the CO_2. Apart from the investment cost required to build the plants, the digester requires heat to operate at the optimal temperature for the process, while upgrading biogas requires power, heat or chemicals depending on the separation technology.

Operating costs are due to feedstock consumption, for which cost was calculated based on average yields of Table 4.1, and energy consumption for biogas production and upgrade. The capital expenditure is mainly related to the construction of the anaerobic digester and the biogas upgrading plant. Different technologies for the upgrading of the biogas into biomethane may lead to slightly different values for both investment and operating cost (in this analysis, the high-pressure water scrubbing system (HPWS) is considered). Currently, most biomethane production plants have small to medium capacities (100-250 Nm^3/h), however, in the last years, the size of digesters has been increasing, and very large plants with capacities of several thousands of m^3/h started to appear in Europe [48]. Figure 4.3 shows the effect of increasing plant size on the cost of biomethane: passing from medium/small scale to very large-scale digesters, the cost of biomethane is halved. In a similar fashion, if low-cost biomass (such as manure) is used as feedstock instead of energy crops, the total cost of biomethane is reduced by 40% (Figure 4.4). It is, therefore, possible to produce biomethane at the cost of 10 $/GJ or even less, and some forecasts assume that thanks to the production scale-up, the future global average production cost will be around 15 $/GJ from 2040 on [7]. The actual costs depend on local economic conditions, and Asian regions are expected to provide the cheapest biomethane with production costs of around 6-12 $/GJ. Although anaerobic digestion and biogas upgrading are mature technologies and significant improvements are not expected in the future, it is still possible to obtain a lower price for biomethane by focusing on larger-scale production, which is, however, limited by the time required by the substrates to produce methane and by the logistics barriers of biomass collection and transport to the plant in large quantities.

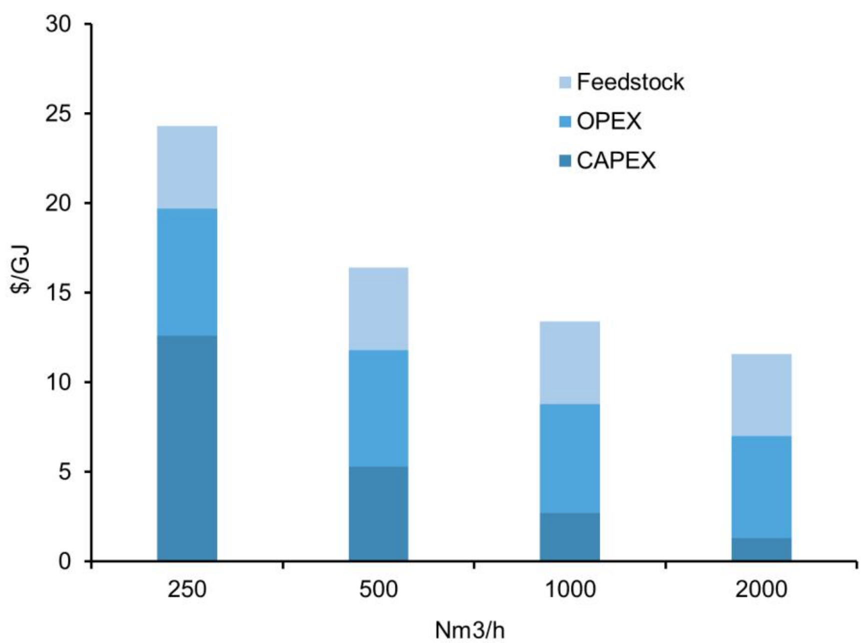


Figure 4.3 – Average production cost of biomethane from agricultural residues by plant size (includes biogas production and upgrading). Cost analysis based on data sources: [7,49].

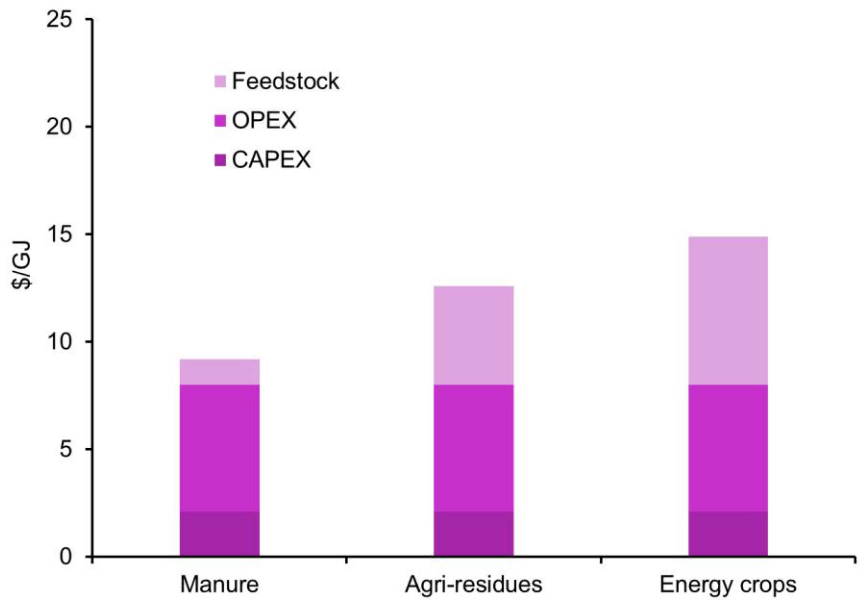


Figure 4.4 – Average production cost of biomethane from a 1000 m³/h unit by biomass feedstock type (includes biogas production and upgrading). Cost analysis based on data sources: [7,49].

4.3.3. Biomethane from thermal gasification

The technology of thermal gasification of biomass is still at a demonstration stage and not yet commercially mature, hence cost and technical data are scarce and often remain confidential among the companies involved in the construction and operation of these plants. However, a few estimates on investment and operating costs for biomass gasification plants can be found in the literature. The main steps to produce biomethane through this pathway are gasification, syngas cleaning and conditioning, and methanation stage to maximise the methane content in the syngas. Biomass gasification is a relatively expensive technology that requires high capital investment. However, such plants can quickly process large amounts of biomass and reach scales up to several hundreds of MW_{th} producing thousands of tons of biomethane every day. The investment costs are shown in Figure 4.5 and Table 4.2, while annual operation and maintenance costs (excluding feedstock) for gasification and methanation plants are set equal to 10% and 5% of the investment costs, respectively [4,50].

The current cost of biomethane from gasification is quite high and even above 30 $/GJ. This is due to many reasons: the need for a refined biomass pretreatment with grinding and drying in order to get the right particle size for the gasifier (typically, the larger the scale, the finer the particles required), the expensive technology for proper cleaning of the syngas, process chain currently not fully optimized [51]. In addition, more commercial experience is required for large-scale operation as there are few plants in the world with capacities above 100 MW_{th} for power generation, while the largest gasification plant for biomethane production is only 20 MW_{th}. A tenfold increase in the scale abates the production cost of biomethane by 30-50% (Figure 4.6).

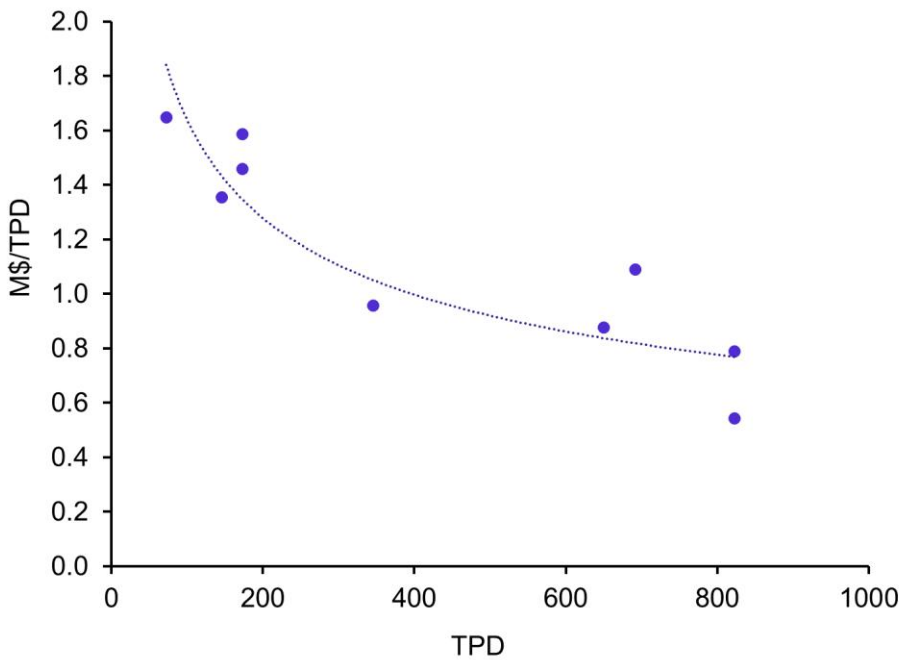


Figure 4.5 – CAPEX of thermal gasification and syngas cleaning plants by size in tons per day (TPD). Cost analysis based on data sources: [4,34,52,53].

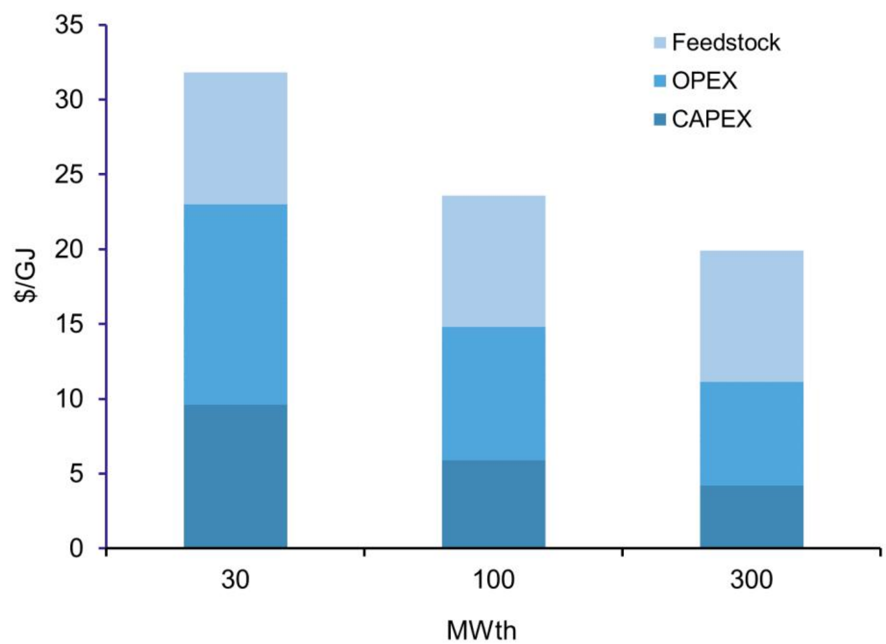


Figure 4.6 – Estimated production cost of biomethane from pre-treated woody biomass feedstock by gasifier size

Table 4.2 – Investment cost and CAPEX for methanation plants. Data sources: [54-56].

TPD	Plant size (kt/y)	Plant cost (M$)	CAPEX (M$/TPD)
5	2	0.8	0.165
8	3	3.3	0.397
9	3	1.4	0.149
22	7	3.5	0.160
42	14	15.9	0.382
217	72	17.4	0.080
868	289	46.3	0.053

4.3.4. Future costs and plant scale-up

The current global average cost of producing biomethane through anaerobic digestion of biomass is around 19-20 $/GJ and could fall to 15 $/GJ by 2040 [7]. Since this technology is very mature and significant innovations are not expected, a reduction of the costs can be achieved solely by increasing the production rate and the size of the digesters and of upgrading units. Today's production comes mostly from small and medium size plants, with an average digester size of around 200-300 Nm^3/h of raw biogas. The construction of a new large-scale digester under the right national policy frameworks could increase the average size up to an optimal cost size of 1500 Nm^3/h of biomethane [13], thus shrinking the costs.

The gasification pathway is significantly more expensive, with an average production cost of 28-33 $/GJ. Further development of the technology and scale-up could lower the biomethane cost by around 12-19 $/GJ in 2050, thus matching the cost of biomethane obtained from upgrading the biogas [48]. Biomass gasification is an important step toward global use and trading of biomethane due to its suitability for large-scale centralised production. However, suitable policies and incentives are required to fund research and pilot plants around the world in order to get large-sized gasification plants for the production of biomethane to become a reality. It is estimated that with the right long-term oriented policies, hundreds of large-scale 200 MWth biomass gasification plants could be built in Europe only [13]. Currently, the very large investment required for a biomass gasification plant is a high risk for investors, and the competition with fossil fuels hampers the scale-up of the technology. Well-established renewable and green gas markets are therefore required for gasification technology to flourish in the markets.

According to recent cost projections from World Biogas Association, Navigant and International Energy Agency, in a few decades, the cost of biomethane from thermal gasification may be equal to the cost of biomethane from biogas upgrading. However, even with production scale-up and technology improvement, the cost of biomethane in 2050 will still be high compared to natural gas price (2-4 $/GJ), even considering the most recent price spikes (8-9 $/GJ).

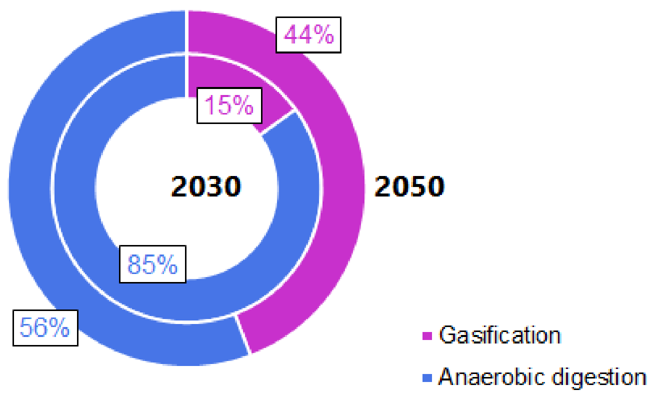


Figure 4.7 – Forecasted share of biomethane produced from AD and thermal gasification in Europe by 2030 and 2050, under proper supporting policy framework. Data source: [13].

Table 4.3 – Current and projected costs of biomethane from anaerobic digestion and gasification. Data sources: [5,7,13,34,39,57-61].

	Anaerobic digestion	**Thermal gasification**
Cost today ($/GJ)	16-28	28-33
Cost in 2050 ($/GJ)	14-18	12-19
Avg cost reduction (%)	22%	46%

4.4. Liquefaction, transport and bunkering costs

Biomethane from the plant gate needs to be liquefied and transported to the bunkering hub to be available for use onboard ships. Each step of the value chain involves additional costs that sum up to the total cost of bio-LNG bunker fuel. Small-scale liquefaction of methane costs around 5 $/GJ, while at a very large scale, this value drops to 2.5 $/GJ; typically, the liquefaction step adds 3-4 $/GJ to the final bio-LNG cost [62-68]. Biomethane can be transported in gaseous form through compression and injection into the gas grid and then liquefied at the end of the supply chain, right before bunkering. Alternatively, it can also be liquefied first and then transported in liquid form by truck and/or vessel. As methane is liquefied at very low temperatures (-160°C), it must be stored in special thermal insulation tanks and is subjected to boil-off. Because of this, the transport of methane by pipeline is significantly cheaper compared to transport by truck or ship in liquefied form. Estimated pipeline transport cost is around 1-1.5 $/GJ [4], while transport by ship may vary between 1-4 $/GJ (50-200 $/ton) depending on charter rate and route distance [69-72], to which one must take in account the extra costs for truck delivery from liquefaction plant to the LNG terminal. Once biomethane is liquefied and transported (not necessarily in this order), it must be stored in proper LNG terminals and bunkered to the ships. This typically adds 60-160 $/ton to the final cost [73-75]. Taking into account the whole value chain from the biomethane plant gate to the bunkering terminal, generally, 250-500 $/ton (5-10 $/GJ) must be added to the final bunker cost.

4.5. Bio-LNG bunker cost

The estimated total cost of bio-LNG today, in 2030 and 2050, is shown in Figure 4.8. Biomethane production cost is based on own analysis and on the IEA forecast [7], assuming a gradual cost reduction until 2040. The transport cost range is calculated assuming pipeline and ship transport costs. Liquefaction cost is considered to decrease gradually from the cost of liquefaction of small/medium scale facilities to large-scale plants, while bunkering cost and port fees range is assumed to be the same as fossil LNG. Currently, bio-LNG would cost around 3-4 times higher compared to the average fossil LNG bunker price (excluding the most recent price spike), but it is expected to decrease mostly due to the lower biomethane cost [76].

Biomethane production accounts for around 70% of the overall cost of bio-LNG to shipowners, liquefaction and transport accountable for another 20%, while bunkering and port fees add up to the final 10%. The average cost for delivered bio-LNG declines by around 30% in 2050 compared to today's values, mainly driven by the reduced cost of producing biomethane in large-scale anaerobic digestion plants. The first tryouts of bio-LNG at sea probably will involve the establishment of dedicated supply chains that do not rely on existing gas grids due to the lack of regulatory frameworks for biogas/biomethane injections in the grid and due to the current absence of green gas certificates. This is the case for the recent bunkering trial of bio-LNG blended with fossil LNG performed by CMA CGM Group and Shell in Rotterdam port. A dedicated supply chain implies high logistic costs, which increase further if the liquefied biomethane is transported over long routes by ship. If future national and international policies will foster the use of the existing gas network to bring biomethane from production plants to existing or new liquefaction terminals in the proximity of major bunkering hubs, the costs could drop substantially.

In the best-case situations, i.e. biomethane from manure and agricultural residues is produced in Asian regions and delivered to major eastern ports, the cost of bio-LNG could reach 20$/GJ and 15 $/GJ by 2030 and 2050, respectively: more than 60% price reduction compared to current costs. Still, bio-LNG will be more expensive than its fossil counterpart, even in 2050. This is mainly due to the extra costs related to biomethane production, which are ultimately dependent on logistic barriers related to the collection and transport of biomass, the fuel production technology, which is more complex compared to the extraction of natural gas and the decentralised nature of biomethane production. Because of all the extra costs, a carbon pricing mechanism needs to be put in place to increase the price of fossil fuels to the shipowner and make green alternatives more competitive on the market. Figure 4.9 shows the value that a hypothetic carbon tax should have in order to make bio-LNG from biogas upgrading competitive with fossil LNG in the next decades. Considering onboard emissions only, burning one ton of fossil LNG causes the emission of 2.75 tons of CO_2 into the atmosphere. If a price is assigned to these emissions, the cost of fossil LNG to the shipowner increases, thus promoting the shift to other alternative fuels. Currently, the cost of bio-LNG is prohibitive due to the lack of a proper infrastructure for fuel production, transport and bunkering, and the required carbon tax to make it competitive with fossil gas ranges from 260-440 $/tonCO_2$.

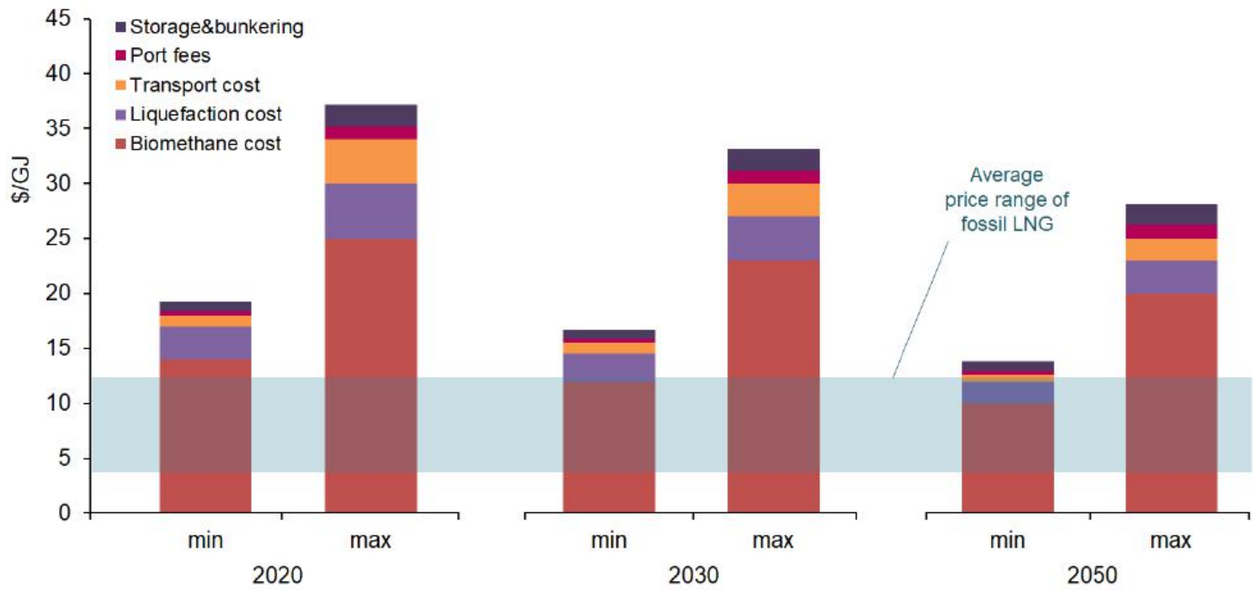


Figure 4.8 – Bio-LNG from anaerobic digestion total cost range in 2020, 2030 and 2050, compared with fossil LNG bunker price (range)

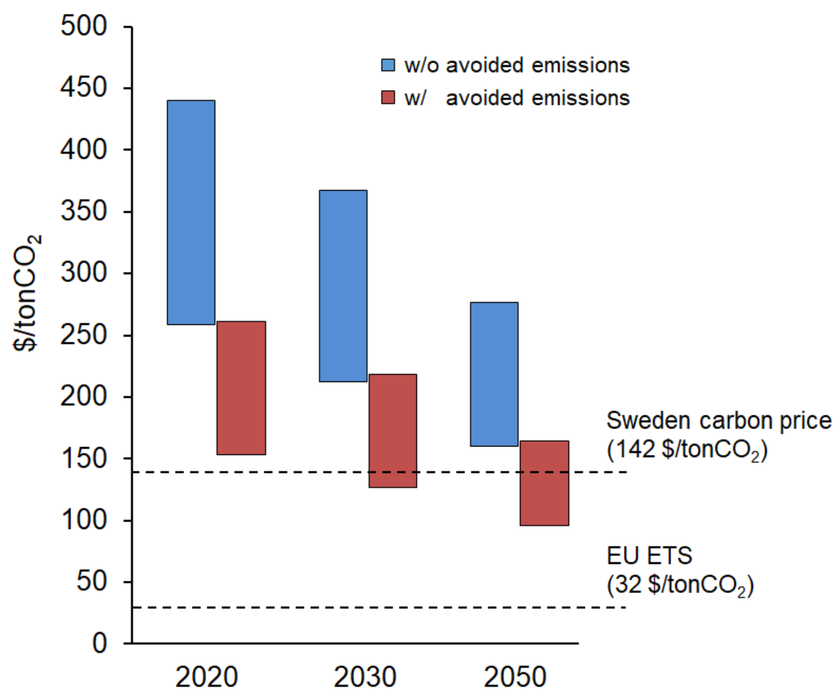


Figure 4.9 – Carbon tax that would be required to increase the fossil LNG cost to equal bio-LNG cost from manure biogas upgrading, in 2020, 2030 and 2050. Lower ranges take into account the avoided methane emissions from manure feedstock.

As the bio-LNG bunker price decreases over time, a lower carbon tax will be sufficient. However, even in 2050, the value stands at 160-280 \$/tonCO_2, which is substantially above the highest carbon tax currently active in the world (Sweden). If bio-LNG is produced from manure or any other waste that is accountable for methane emissions into the atmosphere, the amount of saved emissions reduces the required tax to 120-220 and 100-160 \$/tonCO_2 in 2030 and 2050, respectively, thus potentially making bio-LNG price competitiveness a reality. It should be noted that the situation for other alternative fuels could be even worse, as bio-LNG is cost-competitive with other biofuels.

5. Lifecycle emissions analysis

5.1. LCA analysis

Lifecycle analysis (LCA) is a methodology to evaluate the environmental impact associated with a specific product from a cradle-to-grave perspective. When applied to shipping fuels, it involves the evaluation of the greenhouse gas (GHG) emissions related to fuel production, transport and use onboard ships. LCA is a standardised methodology, defined by the International Organization for Standardization (ISO) in ISO 14040 and 14044, and includes four main phases: i) goal and scope definition; ii) inventory analysis; iii) impact assessment; iv) interpretation. The first phase involves the description of the problem, the boundaries of the system and the definition of the functional unit on which the desired environmental impact is calculated (i.e. 1 kg of fuel, or 1 MJ of energy contained in the fuel). The inventory analysis is the collection of data on the environmental impact associated with the processes included in the system defined in the first phase. In the third phase, the iterative calculation of the ecological impact of the selected product is performed, and in the last phase, the results are interpreted and reviewed to ensure consistency and transparency. Even though LCA analysis was developed for industrial and manufacturing products, with time, many studies applied this methodology to much more complex processes leading to a variety of often contradictory results. Indeed, the relatively high degree of freedom in defining the system boundaries and the assumptions made for the analysis make LCA results from different studies often contradictory and confusing. Unfortunately, the application of lifecycle analysis to biofuels is a major example of this problem.

Lifecycle emissions of marine fuels are divided into two main components:

- **Well-to-tank**: the emissions related to the fuel production and transport to the ship
- **Tank-to-wake**: onboard emissions of the energy conversion system (engine or fuel cell)

The evaluation of the GHG emissions related to the use of fuel onboard a ship requires estimating the gaseous emissions of CO_2 and other gases that contribute to global warming, such as methane (CH_4) and nitrous oxides, and N_2O in particular. This estimation must be performed for each step of the supply chain and allows to identify which processes are the major contributors to the final global warming impact. Typically, the functional unit defined for marine fuels is 1 MJ of energy of the fuel produced and used onboard, based on the lower heating value (LHV). The GHG impact, according to IPCC, is caused by the three main molecules released into the atmosphere from the combustion of fuels and is defined through 100-year time horizon global warming potentials:

- CO_2 (GWP=1)
- CH_4 (GWP=28)
- N_2O (GWP=265), which are a small fraction of NO_x emissions

Evaluating biofuel lifecycle emissions is a challenging task, as biomass feedstock adds an additional level of complexity to the analysis. While the onboard emissions related to the combustion of biofuels in engines are relatively well understood, well-to-tank emissions are much harder to calculate. The cultivation of energy crops, for example, requires the use of land, and the choice of whether to include or not the impact of land use change in the LCA assessment may affect the results in a substantial way. When the land used for crops is converted from a forest, the reduced carbon sequestration in the soil leads to an increase in GHG emissions, which impacts negatively on the overall lifecycle balance of the biofuel. When waste biomass or manure is used as feedstock for biofuel production, the LCA is carried out considering in some way the alternative uses of the feedstock and assigning a CO_2 burden to them, which can be positive or negative, depending on the CO_2 emissions related to the alternative use of the feedstock. For example, manure is typically adopted as natural fertilizer, and if its use is diverted to biofuels, industrial fertilisers may be needed to replace it. The choice of whether and how to include the GHG emission related to the production of fertilisers plays an important role in the results of the analysis.

Some studies on the lifecycle GHG emissions of bio-LNG are available in the literature [77-81]. However, the results vary widely, from negative emissions down to -100 gCO_2eq/MJ to over 150 gCO_2eq/MJ. This happens because of the different assumptions made for the analysis:

- CO_2 burden assigned to biomass feedstock
- Closed or open storage for feedstock and digestate
- Carbon emission factor of the electricity used

To get a clearer understanding of the well-to-tank GHG emissions related to the production of bio-LNG, a lifecycle assessment was performed by means of a professional LCA software: SimaPro.

5.2. Well-to-tank emissions

SimaPro is a professional LCA tool used to perform environmental impact analyses of industrial products and processes. SimaPro includes a detailed database (Ecoinvent) of thousands of industrial processes, and it allows the evaluation of different categories of environmental impacts such as global warming potential, acidification, eutrophication and many others. For this study, the production and transport of bio-LNG were modelled with SimaPro (version 9.3) to evaluate the global warming effect caused by producing and delivering 1 MJ of fuel to the bunkering hub. The method used to assess the global warming impact of the process is the IPCC method (2013), developed by the Intergovernmental Panel on Climate Change, which contains the climate change factors of greenhouse gases within a 100 year horizon.

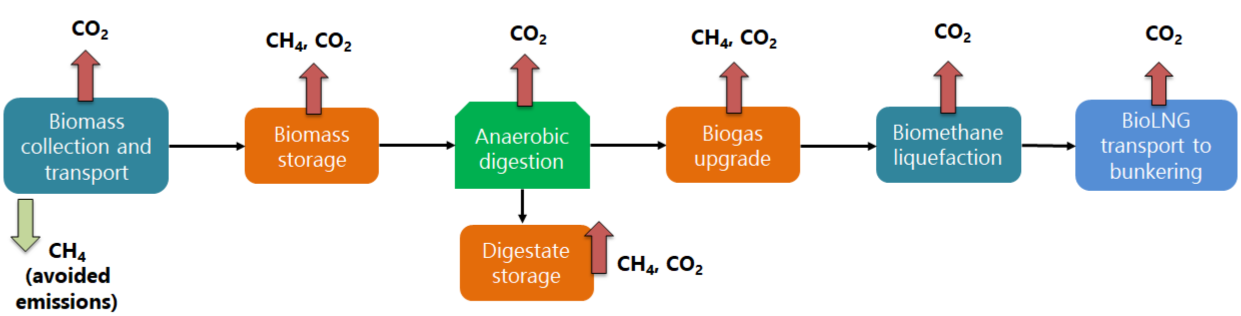


Figure 5.1 –LCA system boundaries and emissions for bio-LNG production from anaerobic digestion

The uptake of atmospheric CO_2 from biomass was not considered, following the carbon-neutrality assumption for biofuels and implying that CO_2 emissions due to onboard biofuel combustion are offset by CO_2 absorbed by biomass from the air during its growth [82]. GHG emissions occur at each step of the bio-LNG production process, and they are mostly related to the CO_2 burden of the energy consumed for processing and transporting the fuel (Figure 5.1). Methane leakage can occur at the biomass and digestate storage stages due to the degradation process of the substrates and during biogas upgrading [83]. If manure is used as feedstock, avoided emissions of methane can be taken into account.

Bio-LNG production was modelled following different assumptions on the process:

- **Production technology**: anaerobic digestion or thermal gasification
- **Feedstock type**: manure, energy crops and woodchips
- **Storage configuration**: closed or open storage for feedstock and digestate
- **Feedstock GHG burden**: avoided emissions from manure
- **Electricity carbon emission factor**: based on 2019 European electricity mix and 2030 forecast

In particular, three production pathways were analysed based on feedstock and conversion technology: i) anaerobic digestion of manure; ii) anaerobic digestion of energy crops; iii) gasification of woodchips. The following paragraphs discuss the LCA models and the relative assumptions.

5.2.1. Bio-LNG from anaerobic digestion of manure

The model is based on the following process steps:

1. Manure input (with associated burden)
2. Biogas production by anaerobic digestion (including storage of manure and digestate)
3. Biogas upgrading to biomethane
4. Biomethane liquefaction
5. Bio-LNG transport by ship

Fresh manure input to the digester was calculated based on an average methane yield of 255 m^3CH_4/ton of dry matter (see chapter 4.3.1).), equal to 46 kg of fresh manure for each m^3 of biomethane (with a 9% DM content). Conventional storage and use of manure as fertiliser in the fields can lead to significant methane emissions, which can be avoided if the waste is used to produce biomethane that is later burned and converted to CO_2. For this reason, the use of manure as a substrate for the production of biogas and biomethane is regarded by some regulations, such as the Renewable Energy Directive (RED II) in Europe, as “improved agricultural manure management” which contributes to emission reduction by preventing field emissions. Manure can emit up to 148 $kgCH_4$/ton of volatile solid content [84]. This credit can be detracted from the GHG emission balance and may lead to overall negative emissions, depending on the assumptions made for the analysis. However, it is crucial to consider that including avoided methane emissions due to alternative uses of manure is a risky practice that may affect the rigour of the analysis from a methodological point of view. As such impact is of an order of magnitude higher than the other GHG emissions in the steps of bio-LNG production, different assumptions on methane release and alternative use of manure may drastically affect the final result.

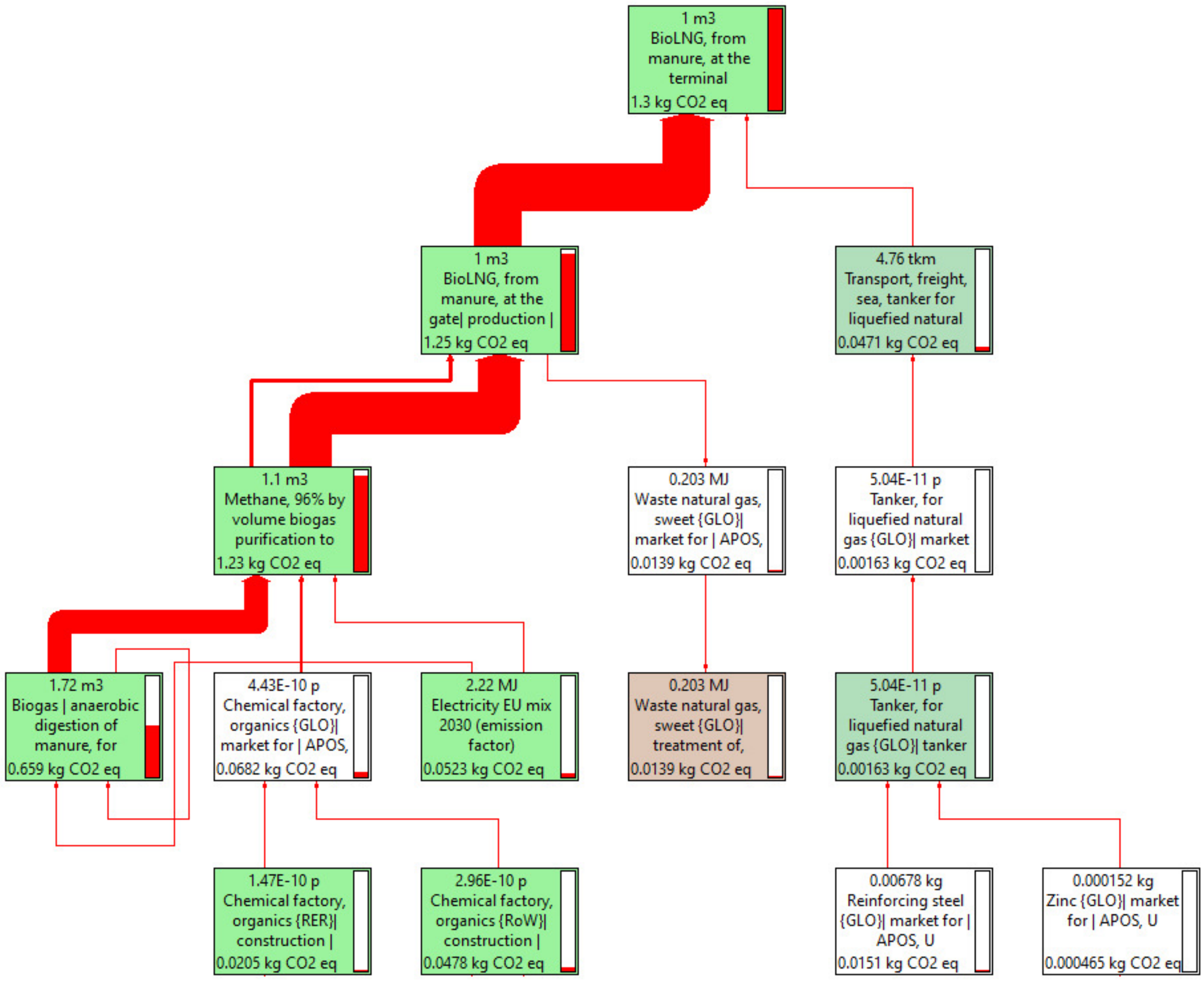


Figure 5.2 – SimaPro model for bio-LNG production from manure

This makes the overall LCA analysis weaker from the methodological point of view. Indeed, even if current manure handling causes methane emissions, such practice may change as more and more attention will be given to such environmental issues in farm practices. If the baseline practice resulted in methane captured and being flared, the avoided emissions related to the use of manure for biofuel production would likely become almost negligible [85]. Moreover, even considering the current bad practice as the baseline case for comparison in the LCA analysis, when avoided emissions are included, the resulting GHG emission factor may lead to preferring less efficient processes that require higher input of biomass (as each kg of such biomass brings a significant avoided emission burden with itself). This is problematic as the most efficient use of resources should always be prioritised. For these reasons, the well-to-tank emissions were calculated by considering manure as a waste stream with no GHG burden and avoided emissions are presented separately from the main balance. Biogas production process was based on the Ecoinvent database in Simapro ("Biogas {CH}|anaerobic digestion of manure"), and it includes, by default, the emissions of methane from the open-air storage of the digestate. For a best-case scenario, closed storage was modelled, assuming that methane release by the substrates is fully recovered and no methane is lost into the atmosphere. The heat required by the process is obtained by burning a fraction of the produced biogas. The treatment of the digestate sludge was not included in the analysis. Biogas upgrading process was based on the "Methane, 96% by volume {CH}| biogas purification to methane 96 vol-%" process, with a baseline assumption of the use of pressure swing adsorption (PSA) technology (1.5% methane slip) and chemical adsorption as best case scenario (0.2% slip) [9]. The liquefaction of biomethane was modelled through the "Natural gas, liquefied {DZ}| production" process in the Ecoinvent database, which describes the liquefaction of natural gas, assuming 10% usage of the produced biomethane (on an LHV basis) to meet the energy requirements. The electricity used in the biogas generation and upgrading has a carbon factor of 275 gCO_2/kWh based on the average EU electricity mix in 2019, while for the best case scenario, a lower value of 86 gCO_2/kWh was set based on the 2030 forecast for EU mix [86]. In the final step, bio-LNG is transported by ship between ports through an average distance of 6000 nautical miles [87].

5.2.2. Bio-LNG from anaerobic digestion of energy crops

The model for bio-LNG produced from energy crops was based on the manure digestion model discussed in the previous paragraph, with modified biomass feedstock input and associated GHG burden. Based on the average yield assessed in chapter 4.3.1., the required input was calculated as 2.06 kg of energy crops (dry matter) to produce one cubic meter of biogas. The cultivation of energy crops generates GHG emissions due to the use of water, fertilisers and fuels to collect and transport the crops included in the model. The literature values for two common energy crops are reported in Table 5.1. The corresponding range of GHG emissions in the well-to-wake analysis was found equal to 3-14 gCO_2eq/MJ of bio-LNG produced.

Table 5.1 – GHG burden due to the cultivation of energy crops

Source	Crop	GHG burden ($kgCO_2eq$/kg dry)
Maas et al. 2013 [88]	Alfalfa	0.141
Ecoinvent database	Alfalfa	0.107
Vivo and Zicarelli 2021 [89]	Alfalfa	0.070
Ecoinvent database	Miscanthus	0.068
Krzyzaniak et al 2020 [90]	Miscanthus	0.034

5.2.3. Bio-LNG from thermal gasification of woodchips

The model for bio-LNG from gasification of woodchips was based on a modified version of an available Ecoinvent process of methane production from synthetic gas produced through gasification technology. The process includes the biomass pretreatment (drying and milling), the gasification of the wood chips with a Fast Internally Circulating Fluidised Bed (FICFB), the syngas cleaning to remove impurities and contaminants, and lastly, the methanation and gas compression. The downstream part of the process is the same as described in the previous models.

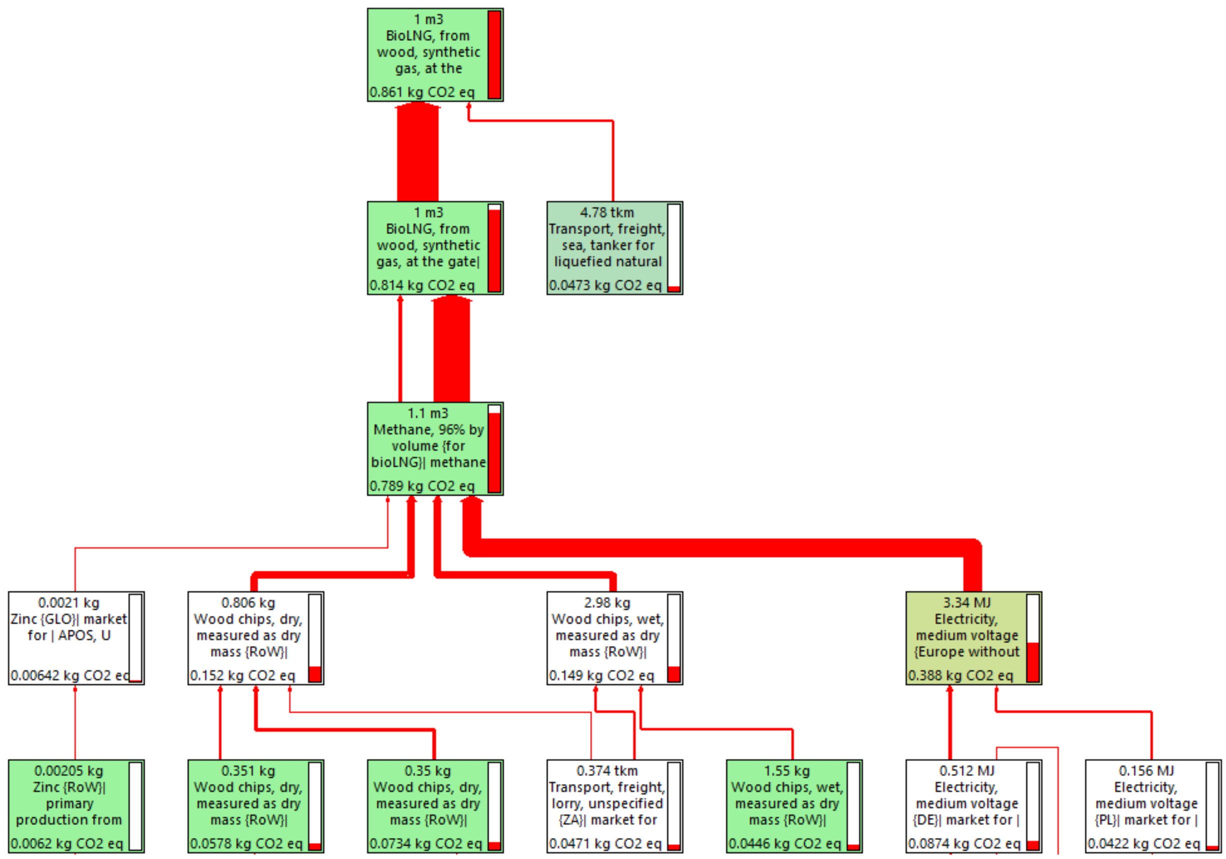


Figure 5.3 - SimaPro model for bio-LNG production from gasification of woodchips

5.3. Tank-to-wake emissions

The combustion of bio-LNG in ship engines causes the emission of greenhouse gases into the atmosphere:

- CO_2 and NO_x emissions due to the pilot fuel combustion (1-4% on an LHV basis)
- CH_4 emissions due to methane slip
- NO_x emissions due to bio-LNG combustion

Assuming MGO as pilot fuel, the related GHG emissions can be calculated by considering the amount typically required by modern LNG engines (1-4% on an LHV basis [91]) and the emissions of marine gas oil (86 gCO_2eq/MJ [92]). For 2-stroke engines, emissions due to pilot fuel are around 0.6-3.4 gCO_2eq/MJ of LNG burned, depending on the engine type. Methane slip is due to unburned methane that can pass through the exhaust and is affected by the load factor, engine type and size. Typically it can vary between

0.2% to 1.5% in 2-stroke engines [93], thus increasing the onboard GHG emissions by 3-27 gCO_2eq/MJ for Diesel cycle and Otto cycle engines, respectively. The emissions due to NO_x are due to N_2O, a potent greenhouse gas, which may amount to 130-220 µg/g of LNG, depending on engine type [91] (0.8-1.3 gCO_2/MJ). The overall tank-to-wake GHG emissions for bio-LNG are 8-28 gCO_2eq/MJ, with methane slip being the highest contributor (40-95%).

5.4. Well-to-wake emissions

The results of the LCA analysis are reported in Figure 5.4 and Figure 5.5 for the worst and best-case scenarios, respectively. If methane leakage along the value chain is not recovered (or burned), the GHG emissions increase substantially, especially for the anaerobic digestion pathways. Indeed, more than 60% of the overall emissions for bio-LNG from anaerobic digestion are due to the methane released by the storage of the digestate, the biogas upgrading step, and onboard combustion. Some studies confirm that if methane losses in biomethane production are not adequately addressed by taking appropriate measures, the overall GHG emission balance comes close to fossil fuels [94]. If avoided emissions from manure are included in the balance, the overall GHG emissions are negative and equal to -44 gCO_2eq/MJ. Energy crops have a higher methane yield, and a lower amount is required to produce 1 m^3 of methane. Consequently, the energy consumption for the digestion process is slightly lower compared to manure. However, growing the crops also requires energy and materials, which carry a GHG burden that eventually overcomes the savings in the digestion process. Bio-LNG from gasification exhibits better performances compared to bio-LNG from anaerobic digestion, thanks to the higher efficiency and the lower risk for fugitive methane across the supply chain. With a low methane slip on board, the thermal gasification pathway can provide excellent GHG emission reduction, almost 80% lower compared with the fuel oil baseline (Figure 5.5). If digestate is kept in closed storage with a methane recovery system, and biogas upgrading is performed with chemical adsorption technology which achieves very low levels of methane leakage (or if fugitive methane from PSA upgrading is recovered or burned), the emissions of bio-LNG from anaerobic digestion are almost equal compared with gasification pathway. When adding the benefits of reduced methane slip from the ship engine, emissions drop to one-fourth compared with the fuel oil baseline for all the analysed cases. If negative emissions from manure are also included, the overall GHG balance becomes negative and equal to -83 gCO_2eq/MJ (in line with the default values for biomethane produced with close digestate storage defined in the EU directive 2018/2001, Annex VI, Section D). Negative values for the well-to-wake emissions imply that using bio-LNG from manure with an optimised production process and improved methane slip actually could actually remove CO_2 from the atmosphere. However, the allocation of negative emissions to manure brings up some methodological issues, as highlighted in chapter 1 and should therefore be done with caution. Instead, focusing on reducing as much as possible the methane released across the production chain leads to more reliable GHG emission reductions. Fossil LNG can provide 14-23% GHG emission savings compared to fuel oil, which is not enough to achieve full decarbonisation alone. However, blending bio-LNG with fossil LNG reduces the lifecycle emissions proportionally to the percentage of bio-LNG in the mix (Table 5.2). A relatively low blend of 30% bio-LNG can provide emission reductions up to around 38% compared to fuel oil and up to 75% when avoided emissions are taken into account, provided fugitive methane emissions along the supply chain are minimised.

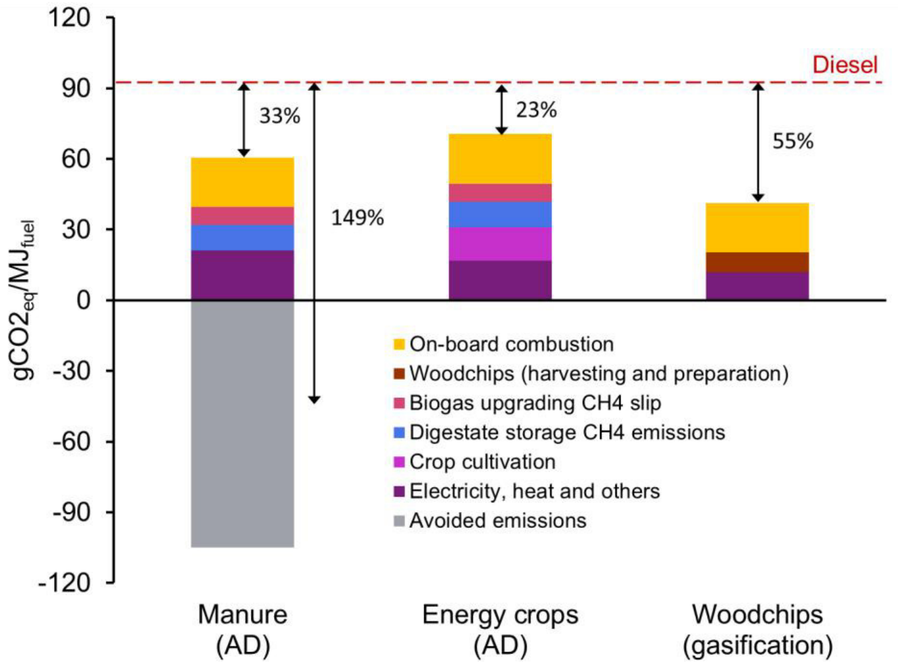


Figure 5.4 – Lifecycle GHG emissions of bio-LNG for shipping, by feedstock type, compared with fuel oil baseline (worst case: open digestate storage, high methane slip, high carbon intensity of electricity, high GHG burden of energy crops). GHG savings for bio-LNG from manure are calculated with and without considering avoided emissions.

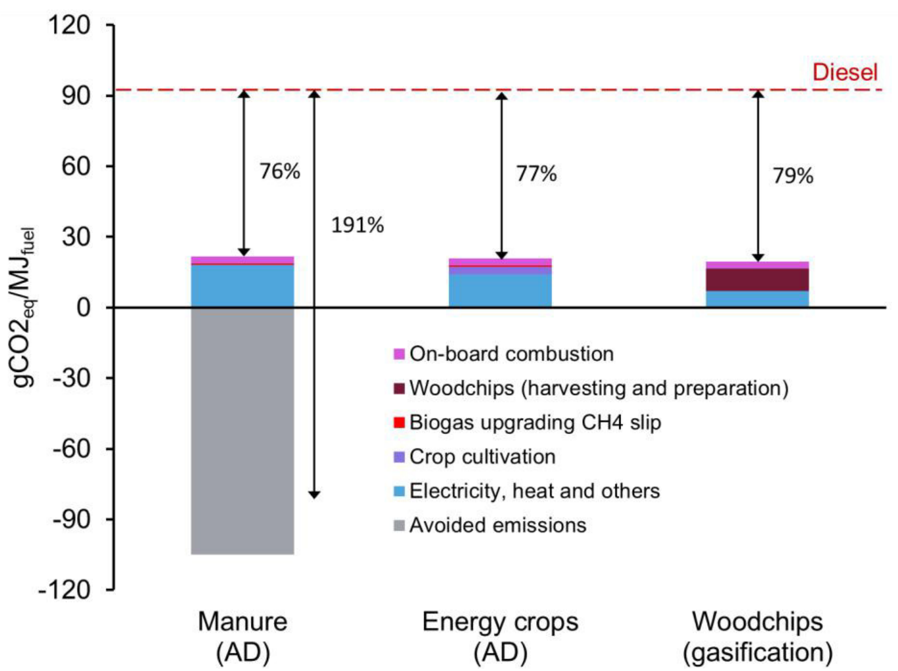


Figure 5.5 - Lifecycle GHG emissions of bio-LNG for shipping, by feedstock type, compared with fuel oil baseline (best case: closed digestate storage, low methane slip, low carbon intensity of electricity, low GHG burden of energy crops). GHG savings for bio-LNG from manure are calculated with and without considering avoided emissions.

Table 5.2 – GHG savings of bio-LNG (from manure) blends with fossil LNG, compared to fuel oil baseline. Best case scenario for anaerobic digestion with minimised methane leakage. The range corresponds to different values of methane slip from 2-stroke dual-fuel LNG engines, which currently correspond to Diesel cycle (0.2%) and Otto cycle (1.5%). Data source: [93].

	GHG savings (%)	
% blending with fossil LNG	**No avoided emissions**	**With avoided emissions**
0%	14-23%	
10%	18-28%	30-40%
30%	26-38%	62-75%
50%	34-49%	95-110%
100%	53-75%	175-196%

The lifecycle emissions analysis showed that bio-LNG is potentially a good candidate for reducing GHG emissions in shipping. However, some key issues of the current production process must be addressed, such as methane leakage across the anaerobic digestion route (a closed storage system is required for the digestate, and leakage from biogas upgrading must be minimised) and methane slip onboard (which has a strong impact on the overall emissions).

6. Logistics and supply chain

6.1. LNG and bio-LNG supply chain

A bio-LNG supply chain (Figure 6.1) can be divided into two main sections: biomass-to-biomethane production and post-production to bio-LNG bunkering. The latter part overlaps with the existing fossil LNG distribution network after fossil methane is produced. The typical key stages of the bio-LNG supply chain include: i) supply of biomass, including collection and transport; ii) pretreatment of biomass; iii) conversion of biomass into biomethane; iv) liquefaction of biomethane to bio-LNG; v) storage of bio-LNG at LNG distribution terminal and vi) bunkering of bio-LNG onboard vessels. Different transportation modes may be employed depending on the characteristics and location of the materials or products. For example, trucks or trains can transport solid materials such as raw biomass feedstock and pretreated biomass over long distances. Bulk carriers may be involved if the location of the pretreatment plant or bio-methane production plant is overseas. However, this may lead to a high final cost of biomethane due to the low energy density of raw biomass. On the other hand, gaseous and liquid materials like biomethane and bio-LNG can also be transported by pipeline and LNG tankers, respectively. Certain stages in the bio-LNG supply chain may sometimes be skipped. For instance, raw biomasses can be delivered directly to a biomethane production plant without any pretreatment. On-site liquefaction can also supply bio-LNG to LNG-fuelled vessels without needing an LNG distribution terminal.

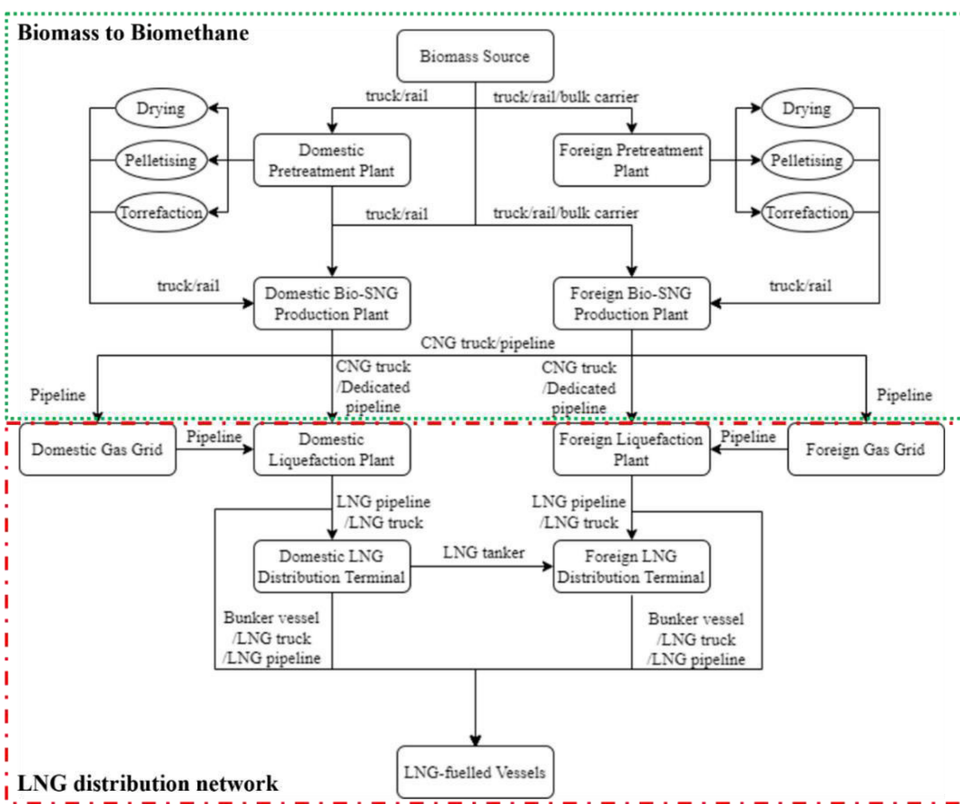


Figure 6.1 – Bio-LNG supply chain structure

6.2. From biomass to biomethane production plant

Biomass for bio-LNG production can come from various sources. The biomass availability varies significantly across different geographical locations, depending on biomass type. For instance, agricultural residue, municipal solid waste and woody biomass are usually the most viable feedstock for large-scale bio-LNG production based on the potential availability. However, their global distributions vary significantly. Both agricultural residue and municipal solid waste have the highest potential in densely populated areas, such as China, India, and the United States. On the other hand, woody biomass tends to locate in the least-populated area, such as Siberia, Northern Europe, North Canada, Amazon Rainforest, and Tropical Africa. Besides the differences in the types of biomass, feedstock seasonality could be another issue. Agricultural residues and forest-based biomass are usually abundant for several months each year but may become scarce in other months. The off-season downtimes may necessitate additional biomass storage (thus implying extra cost) in months of abundance [95]. In addition, low density, low calorific value, and dispersed geographical availability of forest-based biomass can lead to increased collection and transportation costs. Furthermore, unlike traditional fossil fuels, biomass is prone to degradation, especially when importing biomass from a place that is a few months' sea shipping away [96]. The quality of the resulting biofuel can be affected due to the partly degraded biomass.

Besides logistics issues related to the characteristics of biomass, there are other considerations related to how biomass is handled. For example, uncertainties lie behind different biomass harvesting methods, technical characteristics of the selected equipment for handling biomass, the distance between the planting place of the feedstock and the biorefineries, the chosen transportation method, and the chosen pretreatment method [97]. Such uncertainties are related to different biomass supply chain arrangements associated with different final costs and life cycle GHG emissions of the final bio-LNG product [98]. As a result, the final biomass supply cost, including logistics, can be very high depending on the local logistic context. The existing literature on this topic shows that collection, transportation, storage, and preprocessing activities could account for up to 72% of the final cost of biomass that enters a biomethane production plant [95], with the actual biomass material cost accounting for only 28% of the final price. Other studies state that the logistics-related costs might contribute up to 65% of the produced biofuel price [96].

The considerations mentioned above frame a context in which, as opposed to fossil fuels which have less price variability across the globe, future biomethane costs could vary significantly depending on the characteristics of local biomass supply chains.

6.3. Logistics issues related to biomethane production

Generally, the economic performance of the biomethane supply chain can be improved by choosing a suitable production supply chain. Centralised supply chain and decentralised supply chain are the two common choices. A centralised biomethane supply chain usually features an integrated and large-scale production plant that sometimes integrates the pretreatment and liquefaction functions. In a decentralised supply chain, pretreatment and production happen near where the biomass is collected, so that production activities spread out over a series of nodes in a network. Both centralised and decentralised supply chains have their advantages. Centralised production may benefit from using excess heat and products to enjoy the economy-of-scale from increased plant sizes and intermediate upgrading to reduce feedstock transport costs. On the other hand, decentralised production could enjoy better flexibility and potentially lower transport cost of the raw biomass due to shorter travel distances. In general, a compromise must be found between the size of the biomethane production plant and the radius over which biomass is collected in order to minimise the final cost of biomethane. Figure 6.2 provides an illustration of a centralised supply chain and decentralised supply chain in biofuel production. Several studies addressed the different configurations of biomethane production. Aziz et al. (2020) showed an example of decentralised biomethane production [99], in which palm oil mill effluent (POME), a side product in palm oil production in Malaysia, is utilised to produce biogas and subsequently upgraded to biomethane. The estimated energy potential generated from 50k tonnes of POME produced in a year is about 3.2 million MWh of electricity, or 2.19% of the total electricity demand in Malaysia. Another example of decentralised biomethane production is shown in the study of Ahlström et al. (2017), in which the authors illustrated a potential case study of Sweden sawmills using sawdust, wood chips, bark and forest residues as the feedstock to produce biomethane [100].

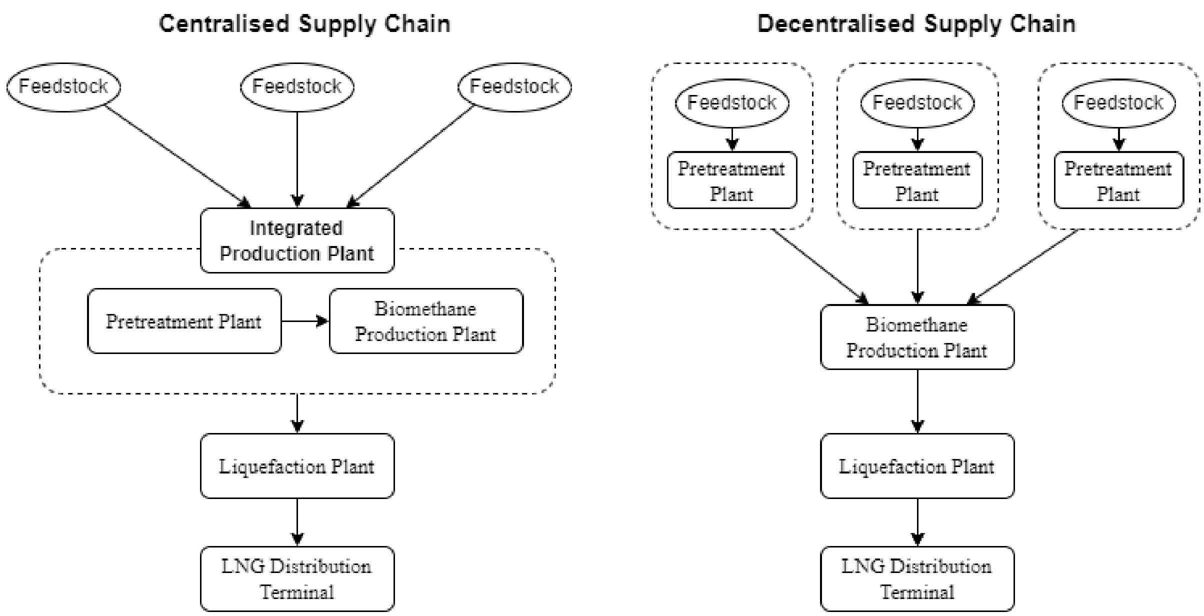


Figure 6.2 - An illustration of centralised supply chain and decentralised supply chain in biofuel production

The feedstocks are assumed to be transported by truck to the sawmill-integrated LNG plant. Transportation from sawmills to LNG terminals is also by LNG trucks. The resulting fuel production cost is estimated to be from 68 to 156 EUR/MWh LNG. Besides examples of decentralised biomethane production, Singlitico et al. (2019) showed an example of centralised biomethane production in a case study applied to the Republic of Ireland with forestry residues as feedstock [101]. The authors examined how an increasing number of production plants could affect the levelised cost of energy (LCOE) and production capacities. Post-production transportation is done through the existing gas network. The results showed that having several production plants leads to a higher production capacity but higher production costs.

Although centralised production tends to apply better with woody biomass feedstock, it is also possible to implement this logistic system using residual waste as the feedstock. Such implementation is usually achievable with the help of the pretreatment of the waste. Calderón & Papageorgiou (2018) illustrated this pretreatment concept in a theoretical UK case study [102]. Two types of transportation were considered in the case study: local transportation by truck and regional transportation by train. Local transportation includes collecting feedstock and delivering BioSNG to consumers within the same region. To implement centralised production using residual waste, decentralised pretreatment facilities have to be installed to convert the residual waste into pellets. This "pelletisation" process could considerably reduce transportation-related costs and reduce the size of centralised production facilities for final conversion into biomethane, implying a lower capital requirement.

Other than centralised and decentralised supply chain arrangements, there are other logistic considerations related to biomethane production. A crucial factor to consider is the optimal plant size or production capacity. The production capacity is significantly related to the production cost. Some studies suggest that plants with lower environmental impact were found between 5 and 40 MW, while the most profitable plants were between 100 and 200 MW [103]. However, more research on the optimal plant size is required. Besides plant size, the chosen production technologies also affect feedstock and energy requirements, costs, final emissions, and the resulting supply chain. Currently, anaerobic digestion may be preferred in biomethane production due to cheaper production costs than gasification. Anaerobic digestion can also serve as an environmentally sound way to handle residential waste [104]. There may be stronger competition on the feedstock used in gasification as the same feedstock could be used to produce other biofuels.

6.4. From biomethane production to bunker bio-LNG

The post-production biomethane distribution network can overlap with the existing fossil LNG network. However, a question remains whether to use existing or dedicated facilities for biomethane for shipping. In a dedicated supply chain scenario, biomethane can be transported and handled using dedicated pipelines, dedicated liquefaction plants and LNG distribution terminals without blending bio-LNG with fossil natural gas. Utilising dedicated facilities reduces the need for green certificates but with potentially high costs [105]. On the other hand, employing existing facilities could significantly lower the distribution costs, but it would need a well-recognised system of green certification for renewable gas. When comparing different transportation modes, it becomes clear that transport by existing pipelines is by far the cheapest pathway compared to other existing transportation modes, such as bulk carriers and LNG carriers [106].

Besides the use of dedicated facilities, the location of biomethane handling facilities is another source of uncertainty in the post-production biomethane supply chain. Handling facilities such as production and liquefaction plants can be located in the domestic country of biomass feedstock or a foreign country. The differences in the locations of the facilities imply different transport methods and costs. Batidzirai et al. (2019) illustrated an interesting case study of the Netherland importing biomethane or feedstock from

Brazil and Ukraine through various transportation modes [106]. The results showed that importing bio-SNG directly by pipeline from Ukraine is the most viable choice regarding the final delivery cost. However, the bio-SNG cost through importing pretreated biomass into the Netherland, where the conversion into bio-SNG happens, is also competitive with bio-SNG cost produced overseas.

6.5. Supply chain configurations

Several uncertainties affect the future bio-LNG supply chain, from biomass sources to the bunkering of bio-LNG. Figure 6.3 and Figure 6.4 summarise the main practices and choices that can be applied to the biomethane value chain.

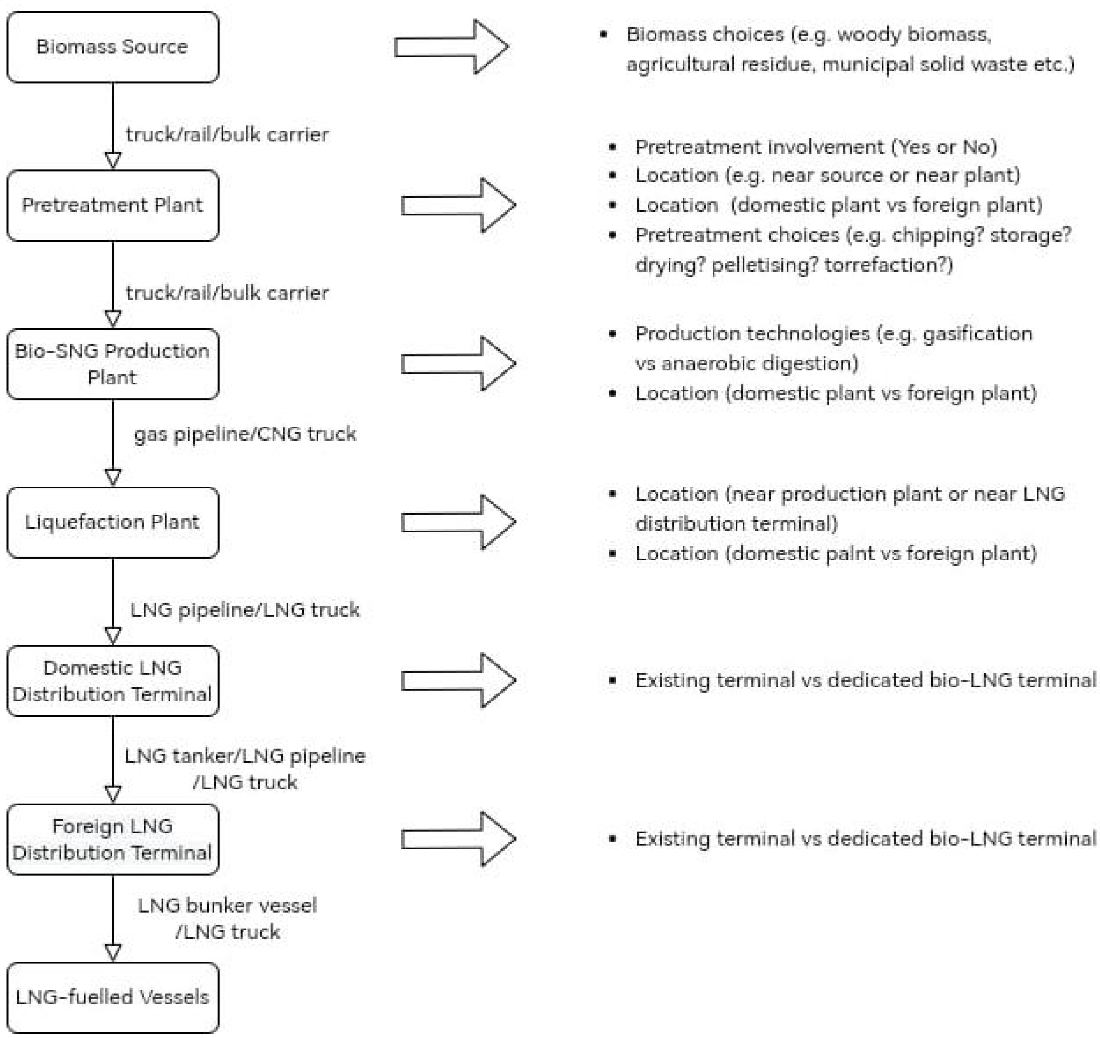


Figure 6.3 - Summary of possible configurations for biomethane supply chain

Delivery cost can be a significant component of the total bio-LNG cost for end-users. As such, centralised production is preferable due to economies of scale and to reducing supply chain costs. On the other hand, a decentralised supply chain may be more suitable for integrated production with bio-LNG as the by-products. The main advantage of adopting dedicated supply chains for bio-LNG delivery to ports is that shipowners can be confident that the molecule purchased at the delivery terminal is the same molecule produced in the renewable gas plant. However, this configuration significantly increases the final cost of bio-LNG due to the significant investment required to establish relevant infrastructures such as dedicated pipelines and terminals. Considering biomethane's relatively high production cost, utilising the existing LNG logistic facilities may be preferred. When using the existing infrastructure to transport the biomethane, biomethane produced from a production plant can be directly injected into the gas grid and subsequently liquefied with fossil gas at a central liquefaction plant. From the end user's point of view, the LNG received by the end users corresponds volume-wise and energy-wise with the biomethane injected into the gas grid. Using the existing gas network and infrastructure to transport biomethane allows for a reduction of the logistic costs, but it requires an appropriate accountability method to ensure that an equivalent amount of renewable gas is injected into the grid for a certain quantity of liquefied biomethane purchased.

A derived application of using the existing infrastructure for biomethane transport is the virtual delivery of biomethane through the use of Green Gas Certificates and Biomethane Guarantees of Origin. Green Gas Certificates are issued for a certain amount of biomethane injected into the gas grid. Subsequently, the Certificates may be transferred multiple times from the producers of biomethane to traders and ultimately to the end bio-LNG users. During the transfer of the Certificates, no physical movement of the biomethane is required. The end users of LNG bought from whatever suppliers can still claim bio-LNG consumption through procurement of the Certificates. The fact that Green Gas Certificates can be traded separately from the conventional LNG market means that the supply chain cost for using bio-LNG could be minimised. However, similar to using the existing infrastructure to transport biomethane, a robust and well-recognised Green Gas Certificates system is required to facilitate the virtual delivery of bio-LNG.

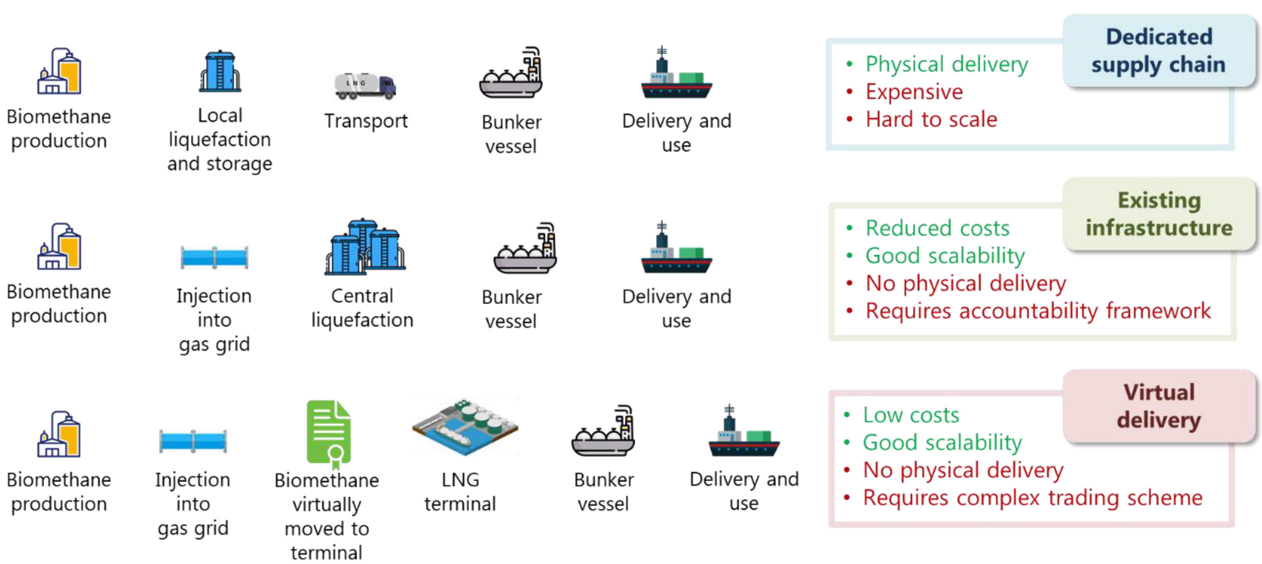


Figure 6.4 – Different possible configurations for bio-LNG supply chain for maritime transport with pros and cons

7. Assessment of the adoption

7.1. Existing energy landscape

To assess the potential impact of bio-LNG adoption in shipping in terms of future emissions, it is necessary to evaluate the energy demand of the shipping sector from now to 2030 and 2050. In this chapter, a future fleet model is presented and will be used to assess whether and how the adoption of different alternative fuels can help the maritime transport sector reach the emissions reduction targets set by the International Maritime Organization.

7.1.1. Key formula

To conduct the world fleet projection from 2020 to 2050 with its energy demand, ship specification data has been collected and consolidated for cargo vessels, including container vessels, bulk carriers, oil tankers, gas tankers, and chemical tankers, forming the 2020 ship portfolio. This choice is related to two main reasons, as elaborated below:

- Availability of data on the mentioned five types of ships
- The emission of CO_2 from the mentioned types of ships accounts for around 75%-94% of total emissions from international shipping.

Historical data on yearly vessel delivery and demolition have been collected and utilised to build time series models to forecast future vessel delivery and demolition number. The future ship number was then calculated using the following equation:

Future ship number = Existing ship number + Future delivery number - Future demolition number

In addition, the ship composition ratio is assumed based on the IMO 4th GHG study to deduce the yearly ship delivery number and demolition number for a sub-class of vessels.

7.1.2. Scenarios

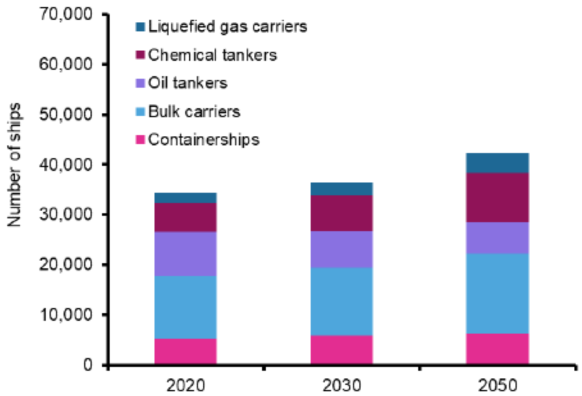
As a future GHG emission baseline, the GHG emission was calculated based on “shared socioeconomic pathways (SSPs)”. The SSPs have been developed by a team of climate scientists, economists and energy systems scientists to examine how global society, demographics, and economics might change over the next century based on future human development, lifestyles, policies, technologies, economies and provision of environmental services [107]. Different combinations of these components lead to various extents of global challenges to climate change. In general, the SSPs represent five global futures for human society (i.e., SSP1, SSP2, SSP3, SSP4 and SSP5). The definitions of the chosen SSPs for this study can be found in Table 7.1. It should be noted that these SSPs have been used as inputs for climate models, feeding into reports produced by the Intergovernmental Panel on Climate Change (IPCC). In this report, SSP1 and SSP5 are considered as they represent opposite pathways related to the use of renewable energy and fossil energy sources. The different scenarios affect the yearly ship number based on the forecasted sea transport demand, as defined by IMO 4th GHG study.

Table 7.1 - Definition and description of SSP1 and SSP5 scenarios used in the analysis

SSP	Assumption for climate mitigation	Description
SSP1 Sustainability	Early accession with global collaboration as of 2020	A world making relatively good progress towards sustainability, with sustained efforts to achieve development goals, while reducing resource intensity and fossil fuel dependency. Technology development is directed toward environmentally friendly processes, including clean energy technologies and high productivity of land. Natural resources are used efficiently, with increased awareness of the environmental consequences of choices. There is a reluctance to use non-conventional fossil fuels.
SSP5 Conventional development	Some delay in establishing global action with regions transitioning to global collaboration between 2020 and 2040	The world is developing rapidly, powered by cheap fossil energy. With the help of technological progress, fossil resource extraction is being maximised at low costs, and local externalities of fossil energy production (e.g. health effects) are well controlled. Due to the firm reliance on fossil energy, alternative energy sources are not actively pursued.

7.1.3. Future energy demand in shipping and GHG emission targets

The total number of ships is expected to grow from 34,288 in 2020 to 42,365 in 2050 based on SSP1 and 59,896 in 2050 based on SSP5 (Figure 7.1). As a result, the net energy demand is expected to reach 6.9 EJ in SSP1 (Figure 7.2) and 9.3 EJ in SSP5 (Figure 7.3). Assuming that the current average energy efficiency of internal combustion engines burning HFO will not change substantially in the future, the estimated total energy demand for the shipping sector is 13.7 EJ in SSP1 and 18.7 EJ in SSP5. A recent study by the International Renewable Energy Agency [108], the world shipping energy demand is expected to reach about 12.4 EJ by 2050, based on a scenario similar to SSP1 and without energy efficiency improvement in shipping. As highlighted in the 4th IMO GHG study, the CO_2 emissions from international shipping range from 740-919 million tons of $CO_{2,}$ depending on the methods applied. According to IMO GHG Strategy, the industry aims to reduce CO_2 emission by at least 50% in 2050 (based on the CO2 emission level in 2008). The estimated total shipping emission in 2018 is roughly the same as in 2008. In this study, five types of major international cargo vessels were considered, namely containerships, bulk carriers, oil tankers, chemical tankers and liquefied gas tankers. For the sake of comparison, the CO_2 emission target is estimated to be 350 million tons of CO_2 for the five major types of international cargo vessels.



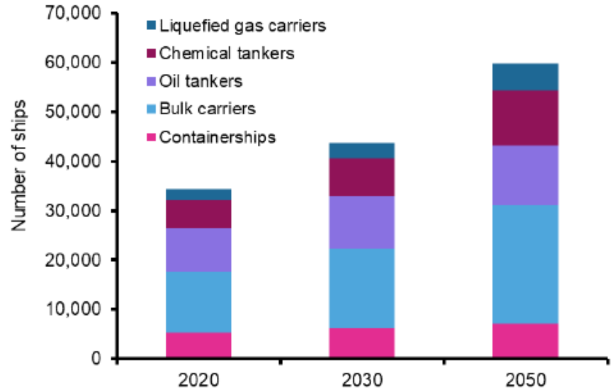


Figure 7.1 – World fleet forecast based on SSP1 (left) and SSP5 (right) scenarios

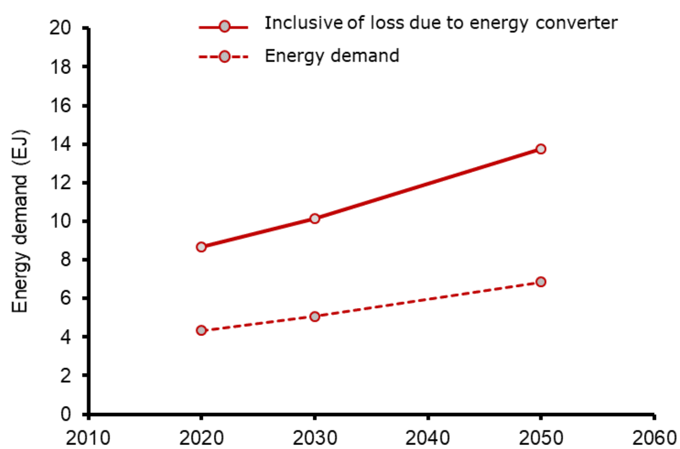


Figure 7.2 – Shipping energy demand forecast based on SSP1 scenario

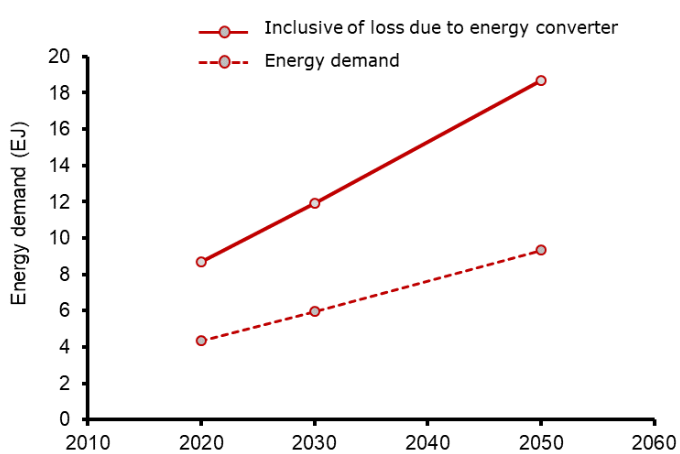


Figure 7.3 - Shipping energy demand forecast based on SSP5 scenario

7.2. Alternative fuels comparison

As shipowners will face increasing pressure from IMO and regional organisations to reduce the greenhouse gas emissions of maritime transport, they will necessarily need to shift to low-carbon fuels. It is possible to divide marine fuels into three main categories:

- **Fossil fuels**, currently used by 99% of world's fleet (fuel oil, marine gasoil, LNG)
- **Biofuels**, obtained through transformation of biomass feedstock (biodiesel, HVO, ethanol, bio-LNG and others)
- **Electro-fuels**, obtained from the combination of hydrogen from electrolysis of water and possibly CO_2 captured from many sources (liquid hydrogen, ammonia, e-LNG and others)

Another possibility is to adopt electric engines and use batteries to run the propulsors. However, this is applicable only to short route shipping due to the low energy density of batteries that require a lot of space onboard.

In order to assess the future role that bio-LNG could play in the shipping sector, it is crucial to put it into a comparative perspective with other potentially interesting low-carbon fuels. The cost and the lifecycle GHG emissions are some of the main factors through which it is possible to assess the attractiveness of a specific fuel for the involved stakeholders in the maritime sector (though not the only ones, as other factors may come into play such as fuel availability and safety features). For this reason, a comparison between the estimated bunker cost of different alternative fuels and their lifecycle GHG emissions is discussed here. The shortlisted fuels and their main features are presented in Table 7.2.

Table 7.2 – List of alternative shipping fuels considered in the analysis with pros and cons

Name	Description	Advantages	Disadvantages
LSFO	Low sulfur fuel oil	Low cost	High GHG emissions
MGO	Marine gasoil		
LNG	Liquefied natural gas		
UCOME	Biodiesel from waste cooking oil	Low GHG emissions Often cheaper compared to other biofuels It does not rely on food crops and oils like other biodiesel fuels	Scarce availability Higher cost compared to fossil fuels
Bio-LNG	Liquefied biomethane	Mature technology for fuel production and onboard combustion It can be blended with LNG Transport and bunkering infrastructure is already developing Low GHG emissions	Cryogenic storage temperature required Current low scale of production Biomass availability

Name	Description	Advantages	Disadvantages
Bio-methanol	Methanol from gasification of biomass	Liquid fuel (alcohol) Can achieve low GHG emissions Low onboard emissions Available experience from engine manufacturers and sea trials	Lacking bunkering infrastructure Mildly toxic Gasification technology not commercially mature
Liquid hydrogen (LH_2)	Liquefied H_2 from electrolysis and renewable energy	Lowest GHG emissions among fuels Zero onboard emissions	Expensive Cryogenic liquid Low energy density Boil-off Infrastructure is costly and currently absent Requires fuel cells
Green ammonia (e-NH_3)	Produced from electrolytic H_2 and N_2 separated from the air	Low GHG emissions It does not contain carbon (no CO_2 capture required) Often the cheapest among the electrofuels	It does not ignite easily (requires significant amounts of pilot fuel) Engine technology not yet proven Extremely toxic gas
Green methanol (e-MeOH)	Synthetic methanol made from electrolytic H_2 and CO_2 captured from fluegas or air	Liquid fuel (alcohol) Low GHG emissions Available experience from engine manufacturers and sea trials	Expensive Mildly toxic Requires CO_2 capture
Synthetic LNG (e-LNG)	E-LNG made from electrolytic H_2 and CO_2 captured from fluegas or air	Low GHG emissions Transport and bunkering infrastructure is already developing	Transport and bunkering are more expensive than e-MeOH It requires CO_2 capture

Even though there are several types of biodiesel available for marine engines (i.e. FAME and HVO), only the biodiesel sourced from waste oil was considered in the analysis. The rationale for this choice lies in consideration of the fact that 1st generation biodiesels sourced from edible oils should not be considered sustainable in the long term due to competition with food uses. For each of the fuels presented in Table 7.2, an estimation of the cost to the shipowner and the lifecycle GHG emission reduction potential was carried out. Due to the scarcity of literature data regarding electrofuels, a cost model was created. The model assumptions and results are presented in the following section.

7.2.1. Electro-fuels production cost

Electro-fuels, also known as power-to-gas fuels, are defined in this analysis as all those fuels that can be produced using green hydrogen as the main feedstock. Hydrogen is generated by separating the H_2 molecule from water using an electrolyser powered with electricity from renewable energy sources such as wind and solar energy. The gaseous hydrogen is then liquefied or combined with nitrogen or carbon dioxide captured from available waste streams from human activity or air to obtain liquid ~~carbon~~ fuels for use in industry, power generation and transport sectors. The future cost of electro-fuels was assessed through a cost model based on available literature data on investment and operational costs for fuel production. The cost of producing hydrogen from the electrolysis of water is currently high but is expected to decrease substantially by 2030 and progressively until 2050 when production cost might get close to 1 $/kg [109]. The main factors influencing the price of hydrogen are the investment cost required for the electrolysers and the cost of renewable electricity. The investment cost for electrolyser systems is expected to drop considerably from current values around 1000 $/kW to 200 $/kW and below by 2050 due to technological improvement and plant scale-up [110,111]. Assuming wind and solar energy as the main sources of the electricity required to produce hydrogen, the cost of renewable energy is expected to decrease by 60% from now to 2050 [112,113], while the average plant size will reach around 400-500 MW by 2050. The capacity factor is assumed to be equal to 90%, and plant lifetime was set equal to 25 years, with a 7% yearly discount rate. Electrolyser efficiency is assumed to be equal to 65%, and the stack lifetime and replacement cost are equal to 70,000 hours and 40% of the total CAPEX, respectively, based on polymer electrolyte membrane (PEM) technology.

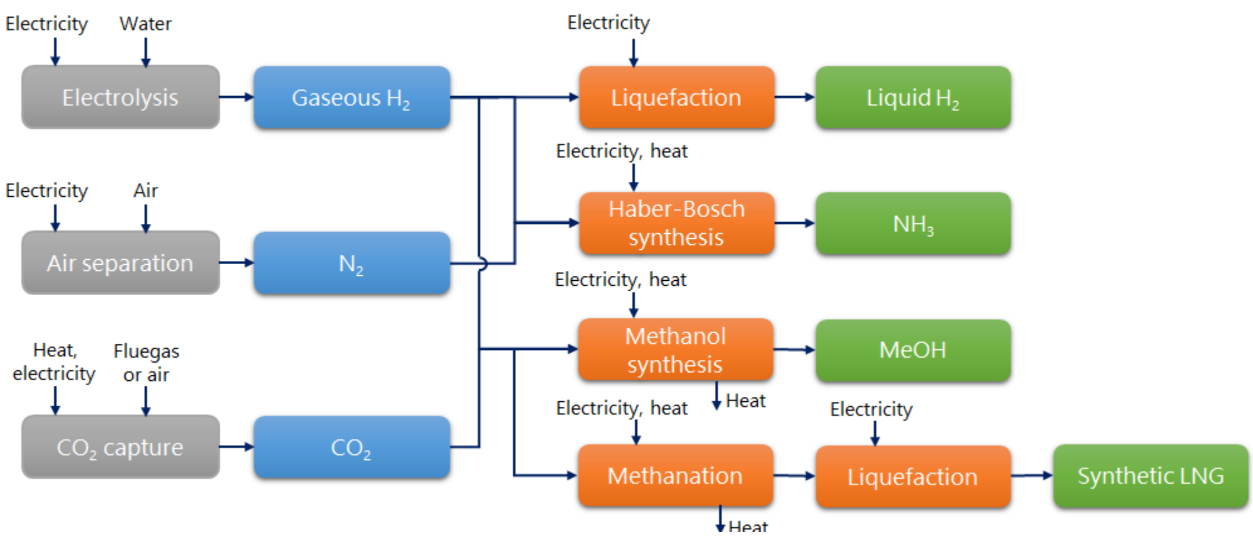


Figure 7.4 – Electrofuels production process scheme

Table 7.3 – Assumptions on hydrogen production and carbon capture parameters, based on literature review

Parameter	2020	2030	2050
Electrolyser system CAPEX ($/kW)	1000	500	200
Renewable electricity cost ($/MWh)	60	40	25
Plant size (TPD)	20	100	200
Carbon capture cost ($/ton$CO_2$)	60 (fluegas)	60 (fluegas)	100 (air)

The cost of green hydrogen calculated in this analysis will decrease from the current value of 5 $/kg to less than 2 $/kg by 2050, a trend in line with most recent forecasts [21,109,110,114]. Once the hydrogen is produced, it is possible to obtain different electrofuels through the processes shown in Figure 7.4. A cost model for each of the processes was elaborated in order to calculate the expected cost of each analysed electrofuel in 2030 and 2050, based on the main parameters shown in Table 7.3.

Table 7.4 – Investment costs, operative costs and energy consumption used in the electrofuel cost model analysis

Parameter	CAPEX (M$)	OPEX (% of CAPEX)	Energy consumption	Sources
H_2 liquefaction	6.05*TPD^(0.87)	3%	13.1*TPD^(-0.2) kWh/kgH_2	[115]
NH_3 synthesis	4.05*TPD^(0.52)	3%	0.363 kWh/kgNH_3	[116-118]
MeOH synthesis	2.43*TPD^(0.48)	2%	0.169 kWh/kgMeOH	[56,119-121]
Methanation	0.40*TPD^(0.70)	5%	1.723 kWh/kgCH_4	[54-56,122]
CH_4 liquefaction	2.91*TPD^(0.56)	4%	0.420 kWh/kgLNG	[123,124]

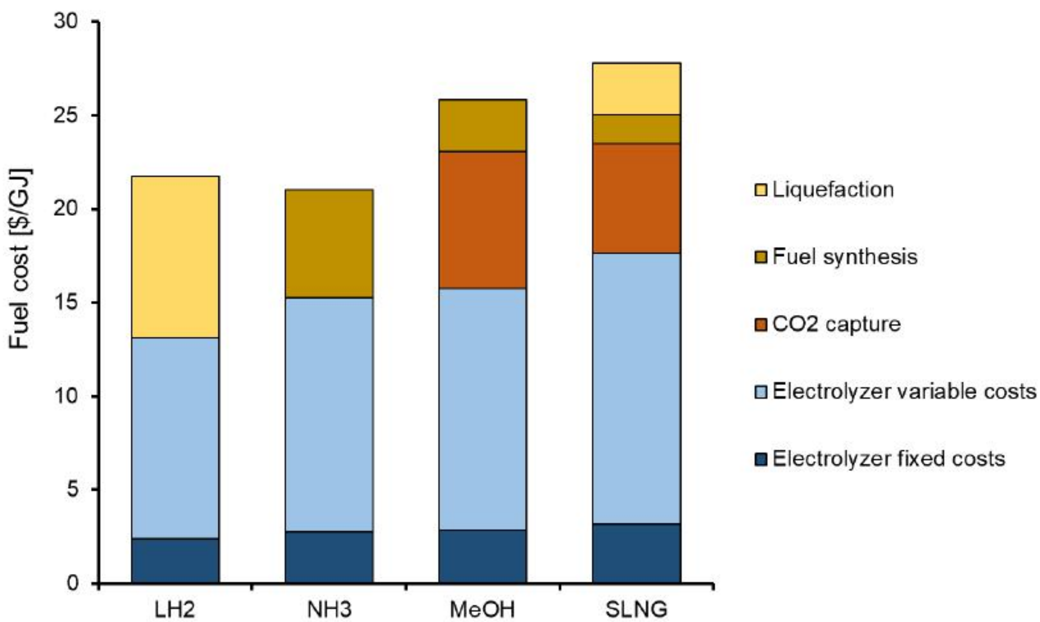


Figure 7.5 – Estimated cost of electrofuels in 2050 (with gaseous H_2 cost equal to 1.6 $/kg)

E-methanol and synthetic natural gas production process requires CO_2, which can be captured from two main sources: fluegas streams from other industrial processes or ambient air. The CO_2 capture process is based on chemical or physical adsorption, depending on the technology, and requires considerable amounts of heat and electricity. Due to the high concentration of carbon dioxide available in the fluegas from industry (i.e. aluminium, steel, cement production), the energy and cost required for the separation are considerably lower compared to carbon capture from air, for which the concentration of the molecule is much lower (<0.05% by volume). For this reason, the cost of CO_2 from fluegas is generally between 50-

100 $/ton, while currently, direct air capture (DAC) requires several hundreds of dollars per single ton of carbon dioxide [125-128]. However, it is expected that with large-scale implementation and process optimisation, the cost of DAC could fall down to around 100 $/ton [129,130].

In the analysis, CO_2 capture from fluegas was considered in the short-medium term, while direct air capture is assumed as the predominant source of CO_2 in the long run. Indeed, all industrial processes will eventually replace the use of fossil fuels and reduce their carbon emissions, thus no longer providing a source of cheap CO_2 for the production of fuels. The main relevant parameters for electrofuel production are presented in Table 7.4. The resulting specific cost per unit of energy to produce the four electrofuels analysed in 2050 is shown in Figure 7.5. Liquid hydrogen and e-ammonia have a similar cost of production, while methanol and e-LNG will be slightly more expensive due to the carbon capture process step. E-LNG requires less CO_2 on an energy basis. However, the liquefaction step adds to the total cost. E-methanol production needs more CO_2 and has a more complex fuel synthesis slightly. However, the produced fuel is already in liquid form and thus does not require further liquefaction. When transport costs are taken into account, liquid hydrogen becomes considerably more expensive than other electrofuels due to the expensive infrastructure required to transport a very low-temperature cryogenic liquid minimising losses.

7.2.2. Alternative fuels cost comparison

The energy cost of analysed alternative fuels is shown in Figure 7.6. The cost for fossil LNG is based on DNVGL data for 2-stroke engines [131], while the cost of methyl ester from used cooking oil (UCOME) is based on historical market prices and ranges anywhere from 600-1100 $/ton [132,133]. According to IRENA analyses [134], for feedstock costs below 6 $/GJ (100 $/ton dry), biomethanol may cost between 300-700 $/ton depending on the investment cost of gasification technology. The cost of bio-LNG from biogas upgrading is based on the present study, and both current and expected future costs were considered. Current production is based on small-scale plants and medium-scale liquefaction, with a biomethane cost between 14-25 $/GJ and a liquefaction cost of 3-5 $/GJ, while the future cost is calculated based on the assumption that future production will scale up and biomethane cost will drop to 10-20 $/GJ by 2040, with a liquefaction cost of 2.5-3 $/GJ. Electrofuels cost range was calculated based on the model discussed in the previous chapter and considered the expected future costs (higher and lower ends of the spectrum represent 2030 and 2050 costs, respectively).

An estimation of the costs for transport and bunkering was also included in the analysis and added to the fuel production cost. Transport costs for e-ammonia and e-methanol were based on average freight rates [135-137]; bunkering and delivery costs for methanol were set equal to 30 $/ton [138], while bunkering cost of e-ammonia was considered the same as for LPG fuel, due to analogue storage conditions (though ammonia may require additional safety measures that might increase the cost). LNG transport costs vary with charter rates, and a common range is 60-120 $/ton [71,72], while bunkering and port fees for LNG delivery vary between 60-160 $/ton [75]. Liquid hydrogen transport is expected to cost around 5-8 $/GJ [114], while bunkering costs were assumed to be 20% higher compared to LNG per unit of volume.

Table 7.5 – Fuel production, transport and delivery cost estimation, based on own model and literature data

Fuel	Production cost		Transport cost		Bunkering and delivery cost		Total fuel cost
	\$/ton	\$/GJ	\$/ton	\$/GJ	\$/ton	\$/GJ	\$/GJ
UCOME	600-1100	14-26	20	0.6	10	0.3	15-27
Biomethanol	300-700	15-35	40	2	30	1.5	19-39
Bio-LNG (current)	850-1500	17-30	100	2	100	2	21-34
Bio-LNG (future)	600-1100	12-23	100	2	100	2	16-27
E-methanol	530-725	27-37	40	2	30	1.5	30-41
Liquid H_2	2800-4100	23-35	800	7	700	6	36-48
Liquid NH_3	410-670	22-36	40	2.1	35	1.9	26-40
E-LNG	1430-2000	29-40	100	2	100	2	33-44

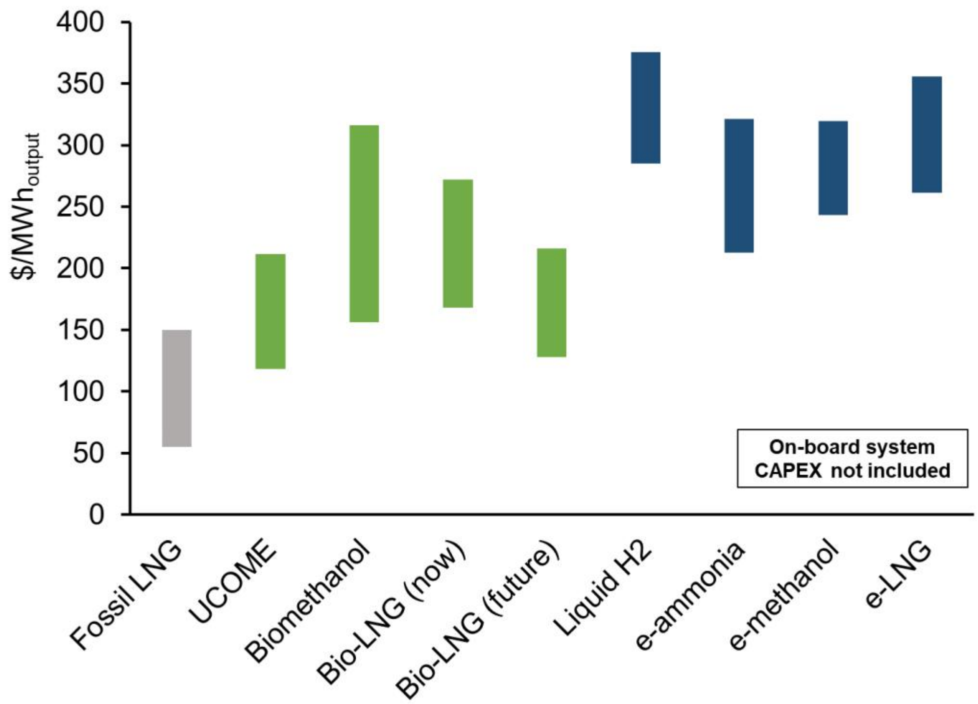


Figure 7.6 – Alternative fuels energy cost comparison, per unit of output energy from the engine. It includes transport and bunkering costs (bio-LNG and e-LNG transport costs are based on fossil LNG, thus implying the use of existing infrastructure). Assumed engine conversion efficiency is 45% (50% for liquid hydrogen used in a fuel cell). (Note: the higher and lower ends of the spectrum represent 2030 and 2050 costs, respectively).

While biodiesel from waste cooking oil is the cheapest among the biofuels, its availability is uncertain due to the limited feedstock resources [133]. Biomethanol and bio-LNG have similar costs per unit of energy, with biomethanol being slightly more expensive due to gasification technology which is more expensive than anaerobic digestion. If the production of biomethane increases globally, the bio-LNG price could become even more competitive thanks to economies of scale. Among the electrofuels, liquid hydrogen has the lowest production costs. However, the high transport and delivery costs make it the most expensive among the electrofuels, even without considering the investment for the fuel cell. E-ammonia is generally cheaper to produce and transport, and its production does not require carbon capture. However, there are uncertainties about fuel handling and engine technology which have not been developed yet, and reliable data on onboard conversion system costs and end efficiency are not yet available. E-methanol and e-LNG have similar costs for transport and bunkering per unit of energy. Indeed, even if a gallon of methanol is cheaper to store and transport compared to an equivalent amount of LNG, it carries less energy due to the lower energy density. E-LNG total energy cost is slightly higher compared to methanol, mostly due to the production process, which requires liquefaction. The cost analysis shows that bio-LNG is potentially competitive with biomethanol and sustainable biodiesel in terms of costs and can be an interesting candidate among future fuels for shipping. E-LNG cost is slightly higher compared to methanol and ammonia but cheaper than liquid hydrogen.

7.2.3. Alternative fuels lifecycle GHG emissions

As discussed in chapter 5 of this study, Bio-LNG has the potential to provide considerable emission savings when compared to fossil fuels. This chapter offers instead a framework which serves as starting base to compare bio-LNG with other alternative fuels in terms of GHG emissions throughout the value chain. The analysis was based on both literature review data and modelling on SimaPro LCA software and aimed at estimating the emission reduction potential of different fuels. Due to the complexity of the problem, lifecycle GHG emissions fall into a wide range depending on the assumptions made for the value chain. The analysis covers well-to-tank emissions, which are due to the fuel production process, while onboard energy conversion (in engine or fuel cell) constitutes the tank-to-wake emissions. GHG emissions related to fuel transport were not considered in the study.

Fossil LNG

Well-to-Tank GHG emissions for fossil LNG are mainly due to carbon dioxide emissions related to energy consumption for gas extraction, processing and transport and methane leakage throughout the value chain. The vast majority of the emissions (around 75%) is, however, due to the onboard combustion, which releases carbon dioxide and methane (due to slipping from the combustion chamber) into the atmosphere. According to a recent study from Sphera [93], fossil LNG emissions from 2-stroke slow-speed engines (which burn 70% of the fuel used in shipping) are 14-23 % lower compared to diesel.

Used cooking oil methyl ester (UCOME)

Biodiesel from waste oil is one of the best-performing fuels in terms of GHG emission savings. However, its production involves some amount of carbon dioxide emissions into the atmosphere. Waste cooking oil is first collected from catering and agro-food industries, then pre-treated to remove unnecessary solids and increase glycerides and free fatty acids content, and finally, through a transesterification process, it is transformed into biodiesel. Well-to-Tank emissions for UCOME are very low and in the range of 0.23-0.55 kgCO_2eq/kg biodiesel (5-13 gCO_2eq/MJ) [139,140]. Biodiesel combustion typically involves lower carbon emissions and slightly higher NO_x emissions compared to fossil diesel. It is commonly used as a blending fuel as if used in the pure form, the properties of biodiesel may degrade and cause some problems in engine systems [141]; current standards allow blends up to 30% [142]. Onboard emissions for UCOME combustion were evaluated based on diesel emissions [91], considering carbon dioxide emissions as neutral as biodiesel contains biogenic carbon. For the sake of comparison with other biofuels, emissions of pure biodiesel (B100) were considered. However, in reality, biodiesel is likely used in a blend with fossil diesel, and the amount of GHG emission reduction that can be achieved varies with the chosen blending rate.

Biomethanol and e-methanol

Biomethanol is mainly produced from the gasification of woody biomass or waste products from the pulp industry (black liquor). The emissions related to biomethanol production are primarily due to the energy consumption (in the form of electricity) for the gasification process, syngas cleaning and methanol synthesis. IRENA has published an outlook study on renewable methanol with a literature analysis on lifecycle emissions of biomethanol for different production pathways [134]. Different assumptions on the carbon footprint of electricity used in the process lead to substantially different values for well-to-tank GHG emissions of biomethanol [143]. When process electricity comes from renewable energy sources such as solar, wind or biomass energy, biomethanol can be produced with low GHG emissions (around 5-23 gCO_2eq/MJ) if sourced from waste wood and even lower emissions when produced from black liquor [134]. However, if the electricity comes from the national electricity mix, the resulting emissions may be much higher (up to 50-60 gCO_2eq/MJ), depending on the emission factor of electricity [143,144]. Lifecycle GHG emissions for e-methanol were evaluated based on material inputs of 0.2 kgH_2 and 1.46 $kgCO_2$ for 1 kg of produced methanol. Wind energy was assumed as the source of the electricity required to capture CO_2 from the air, while the required heat can be obtained by burning a sufficient amount of hydrogen produced by the electrolyser. Methanol synthesis requires 0.169 kWh/kgMeOH [121]. Onboard emissions of methanol fuel are considerably lower than diesel, and SO_x, PM and NO_x emissions for methanol engines are 99%, 95% and 60-80% lower, respectively, compared to fuel oil [143]. Considering biogenic carbon, tank-to-wake emissions of biomethanol are mainly due to N_2O emissions and are equal to approximately 2.5 gCO_2eq/MJ. Methanol engines require small amounts of pilot fuel, and a 5-95% diesel-methanol mixture was considered in this study [145].

Liquid hydrogen

Well-to-tank emissions of liquid hydrogen are largely due to the electricity consumed for the electrolysis of water (around 51 kWh/kgH_2) and the liquefaction of gaseous hydrogen, which requires around 30% of the processed hydrogen energy on an LHV basis (10 kWh/kgH_2). Another potential source of GHG emissions is related to hydrogen leakage throughout the value chain: molecular hydrogen is indeed an indirect greenhouse gas (recent estimates on the global warming potential assess a GWP equal to 11) [146]. While the production and transport of liquid hydrogen results in a global warming impact, onboard emissions are negligible if hydrogen is used in a fuel cell. It is estimated that producing LH_2 from renewable power generates 9-16 gCO_2eq/MJ only [131,144]. If a 10-15% hydrogen leakage along the supply chain is also considered [147], lifecycle GHG emissions increase to 18-30 gCO_2eq/MJ.

E-ammonia

GHG emissions from e-ammonia production are slightly higher compared to liquid hydrogen. To produce 1 MJ of fuel energy, more gaseous hydrogen is needed to synthesize NH_3 compared to pure hydrogen (around 15% more). Ammonia synthesis is an energy-intensive process that requires significant amounts of electricity. The GHG impact of ammonia production was calculated based on the wind energy required to produce hydrogen and nitrogen and to synthesize ammonia [116,117]. Since no ammonia engine is currently available on the market and the technology is still in development, onboard emissions estimates are not available in the literature. It is known that the combustion of ammonia releases high amounts of nitrous oxides [148,149], and this issue must be addressed as N_2O has a very high GWP impact.

Considering that ammonia engines need to comply with Tier II emission limits, an onboard NO_x emission reduction system such as a selective catalytic reduction (SCR) system will probably be needed. It can be assumed that future ammonia engines will comply with NO_x regulations; therefore, for the analysis, an emission of 14 g NO_x/kWh of engine output was considered, with N_2O concentration abated at levels of diesel [91]. With these assumptions, onboard emissions add up to 1-2 gCO_2eq/MJ. Ammonia has a limited flammability range and, therefore, will likely require a pilot fuel for efficient combustion (5-20%) [150-152]. If diesel is injected with ammonia for this purpose, additional onboard emissions of 3-12 gCO_2eq/MJ must be considered, depending on the amount of pilot fuel used. However, in the long term, biofuel or even hydrogen may be used as pilot fuels. It must be noted that there is high uncertainty about onboard emissions of ammonia, as the technology needs to be proven and the first ammonia engines will likely enter the market not before 2024 [150].

Bio-LNG and e-LNG

Bio-LNG emissions data were taken from the LCA study performed and discussed in chapter 5. Reliable literature data on the GHG impact of the use of e-LNG in shipping is not available. Therefore, for this study, a simplified LCA model was built with SimaPro software for lifecycle analysis. The four main contributions to the GHG emissions in e-LNG production that were considered are: i) H_2 production (electrolysis of water); ii) CO_2 capture (direct air capture); iii) CH_4 synthesis (methanation); iv) methane liquefaction.

Gaseous hydrogen is produced with an electrolyser with 65% efficiency, thus requiring 29 kWh/kg of methane. To synthesize methane, almost 3 kg of CO_2 is required for each kg of CH_4 [56,122]. The carbon dioxide capture process from ambient air requires both electricity and heat. With a plant configuration optimised for the production of electrofuels [130], it is estimated an energy input of 0.37 kWh/$kgCO_2$ in the form of electricity and 1.46 kWh/$kgCO_2$ in the form of heat. If the heat required for CO_2 separation is obtained by burning hydrogen produced in the electrolyser, thus avoiding the use of fossil fuels, an additional 7.3 kWh/kg of methane must be provided to the electrolyser.

Methanation energy inputs were set equal to 1.7 kWh/$kgCH_4$ [122], while the subsequent liquefaction step requires 10% of the processed gas on an LHV energy basis, according to the SimaPro process database. Electricity for the whole process comes from wind energy, with a carbon emission factor of 13 gCO_2eq/kWh [153-155]. It must be considered that with a GWP=25 for methane, a 1% loss across the value chain would cause an increase in the overall lifecycle GHG emissions of 5-6 gCO_2/MJ. It is, therefore, crucial that methane losses are minimised, and boil-off gases are recovered during the production and transport of e-LNG. In this analysis, a range between 0-2% methane losses along the supply chain was considered (0-11 gCO_2/MJ).

Onboard emissions for bio-LNG and e-LNG are due to the NO_x emitted during the combustion process. However, any small amount of methane escaping from the combustion chamber of the engine rapidly increases the global warming impact of this fuel. Engine manufacturers are putting significant effort into the reduction of methane slip, and great improvements in the combustion processes are expected to decrease the methane losses to 0.4-0.8 g/kWh of engine output by 2030 (0.3-0.6 % slip) [93], which corresponds to 4.5-9 gCO_2eq/MJ. In this analysis, a methane slip of 0.2-1% (3-15 gCO_2eq/MJ) was considered. Typical N_2O-related emissions from LNG engines were also included [91], with GHG emissions in the range of 0.8-1.3 gCO_2eq/MJ.

LCA comparison

All the analysed fuels can provide significant emission reductions compared to diesel. However, the calculated emissions fall into wide ranges due to the different assumptions about the fuel production process (Figure 7.7). Biodiesel from waste cooking oil is the best performing fuel. However, it can currently only be blended with conventional fuels. UCOME B30 blends with fuel oil reduce the overall emissions by 25-28% compared to the baseline. Bio-LNG emissions are high if open storage is used for biomass feedstock and digestate due to the high amounts of methane released and lost into the atmosphere. Instead, adopting closed storage with methane recovery systems drastically reduces the GHG emissions, making bio-LNG from anaerobic digestion competitive with biofuels from gasification (i.e. biomethanol). However, in the long term, with improvements in gasification technology and the availability of cheap renewable electricity, biomethanol will achieve higher emissions reduction, represented by the lower part of the range in the graph (and so will bio-LNG from gasification).

The highest emission reductions, above 70%, are obtained when bio-LNG is produced from manure, with low methane slip onboard. In the specific case of bio-LNG produced from anaerobic digestion of manure, if avoided emissions are taken into account, the resulting GHG emissions are negative and therefore outcompete all the other fuels. Liquid hydrogen is the best performing electrofuel, even when considering H_2 leakage along the supply chain. E-ammonia achieves similar emission reduction potential compared to other electrofuels, provided that ammonia engine technology will be proven to meet Tier II limits for N_2O emissions. If improvements in combustion technology or clean pilot fuels are available, reductions up to 70% and more are expected. Most of the GHG emissions for e-methanol are due to fuel production, and the best performance is related to the availability of clean CO_2 from biomass or geothermal plants. E-LNG from wind energy and DAC-captured CO_2 will be competitive with other electrofuels in terms of lifecycle equivalent CO_2 emissions. However, its GHG footprint is very sensitive to methane losses along the value chain and onboard the ship.

Assuming that methane losses along the value chain are minimised and onboard methane slip is negligible, the use of e-LNG offers emission reduction up to around 80% compared to diesel fuel. However, with increasing methane losses into the atmosphere, the performance gets worse: 56% reduction considering 1% methane slip onboard and 2% methane losses along the supply chain.

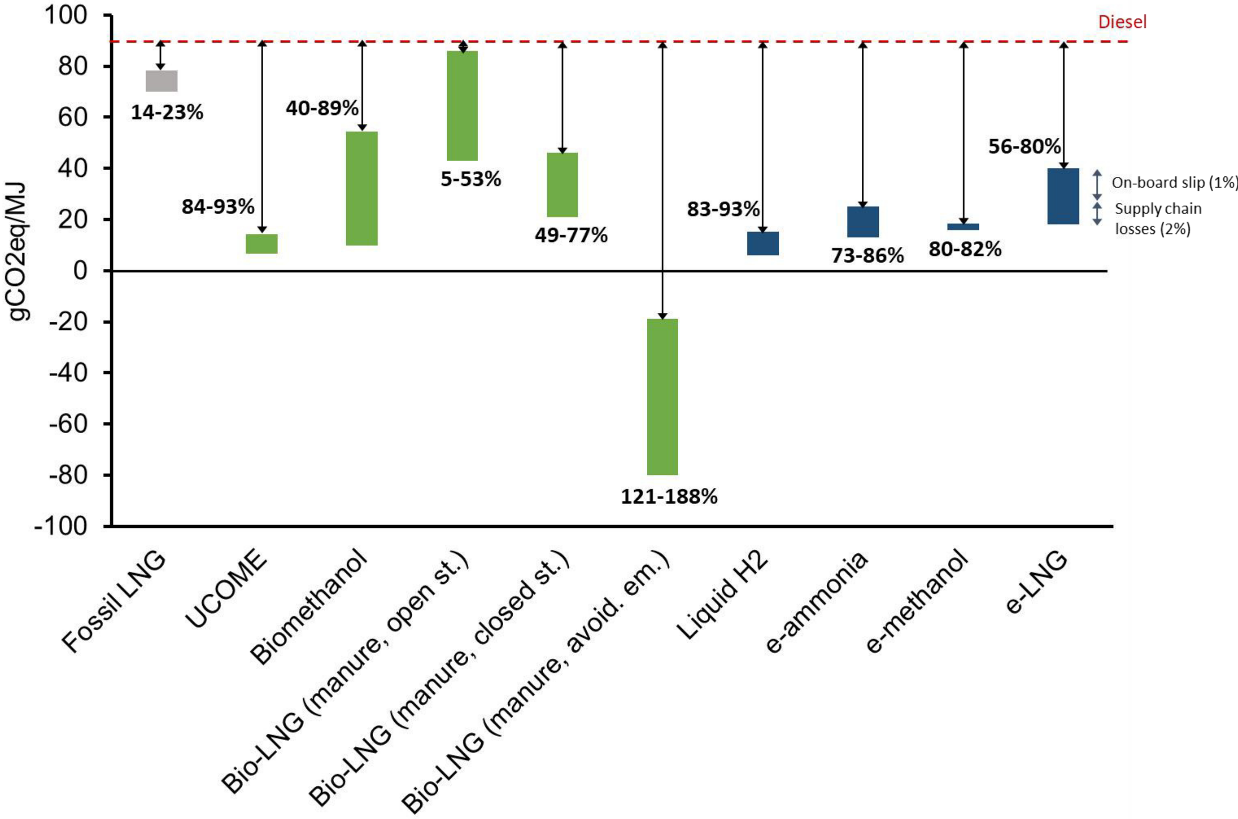


Figure 7.7 – Lifecycle GHG emissions of alternative fuels compared to diesel. Includes emissions during fuel production and onboard emissions. Electrofuels are produced with wind energy and their cost range is estimated for 2050.

7.3. Bio-LNG adoption

The future fuel landscape and the rate of adoption of alternative fuels in shipping will depend on many factors such as fuel price and relative carbon footprint, fuel handling and safety practices, infrastructure development for alternative fuel transport and bunkering, incentive policies for the adoption of GHG mitigation measures and carbon pricing. It is, therefore, very complex to make forecasts about the future fuel mix in shipping. However, it is possible to make a simplified assessment of the "likeability" of different fuels based on the future cost for fuel and onboard system and related GHG emissions. A fuel adoption assessment model was used to evaluate the adoption of alternative fuels in shipping from now to 2030 and 2050. Considering two different global scenarios for the pathway of society towards sustainability and different assumptions on the future carbon price, the total cost of ownership for each fuel was calculated year by year, and potential adoption pathways from the shipping fleet were evaluated. The total emissions from the maritime sector were then compared with IMO targets to check whether the adoption pattern would be compatible with future emission reduction goals.

7.3.1. Method overview

A simplified adoption model was built to assess the future shipping demand for different alternative fuels, and Figure 7.8 presents the overview of the bio-LNG adoption model, with key inputs and outputs. The evaluation of the adoption of alternative fuels is based on Net Present Value (NPV) as a parameter to determine whether a ship owner will adopt an alternative fuel or conventional LSFO.

$$NPV = \sum_{t=0}^{T} \frac{Fuel\ cost_{lsfo} - Fuel\ cost_{alt}}{(1+r)^t} - CAPEX$$

T: The number of years expected of interest. Ten years is assumed in this study.
CAPEX: Conversion cost to adopt alternative fuel from using LSFO
Fuel Cost$_{lsfo}$: Annual fuel cost when using LSFO
Fuel Cost$_{alt}$: Annual fuel cost when adopting an alternative fuel.
r: Discount rate (%), assumed at 5% in this study

Besides the adoption criteria, this model utilises several assumptions as the model inputs. The assumptions on CAPEX of engines and respective discounted factors of the CAPEX are given in Table 7.6, while assumptions on the fuel costs, including distribution and storage costs, are provided in Figure 7.9. For simplicity, onboard emission factors are adopted in the model.

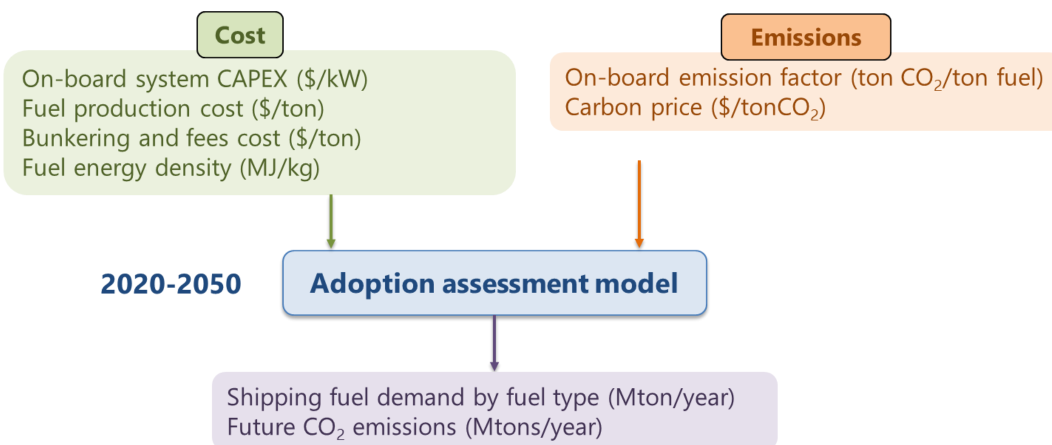


Figure 7.8 – Overview of the alternative fuel adoption assessment model

Table 7.6 - Assumptions on CAPEX of engines and discounted factors. Data source: [156].

Engine type	CAPEX (USD/kW)	Discount 2030	Discount 2050
Diesel engine	595	1	1
LNG engine	1013	0.9	0.9
Hydrogen fuel cell	2611	0.8	0.4
Methanol engine	658	0.9	0.7

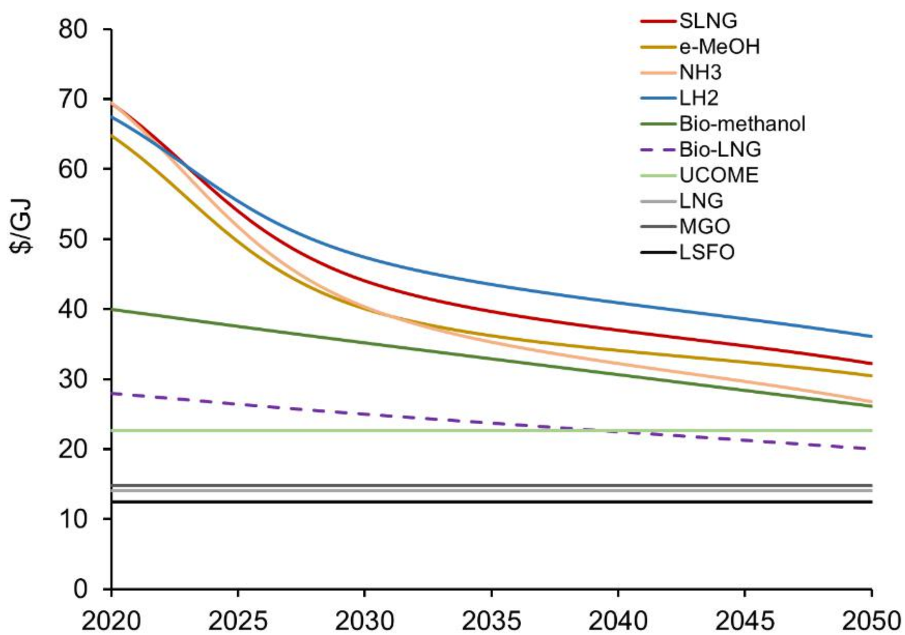


Figure 7.9 – Model assumptions on the cost evolution of fossil fuels and renewable fuels (including distribution and storage cost) over time

7.3.2. Model results

Figure 7.10 and Figure 7.11 present the estimated fuel demand at different CO_2 prices in SSP5 and SSP1, respectively. When the CO_2 price is higher than 145 USD/ton and less than 235 USD/ton, the IMO's 50% emission reduction target by 2050 is not met in either SSP5 or SSP1. Biodiesel (i.e. UCOME B30) will become the dominant fuel in the future. However, the resulting demand for UCOME will most likely exceed the availability. Bio-LNG and bio-methanol will start to be adopted only in the late 2040s. When the CO_2 price is higher than USD 235/ton, IMO's targets can be met in the sustainable development scenario (SSP1). Firstly, the demand for UCOME B30 peaks in 2030. Subsequently, bio-LNG will start to be adopted in 2025 and become the dominant fuel by 2040. The forecasted supply of bio-LNG by 2050 for shipping will likely be fully utilised. The additional demand may be covered by bio-methanol demand or bio-LNG (gasification). In the SSP5 scenario, the demand for bio-LNG varies significantly by the change in expected ship demand in the future. Despite several limitations of the adoption models due to the simplified assumptions, it is possible to get a few key outcomes from the analysis. Firstly, bio-LNG emerges as a viable option among other fuels if the carbon price is high enough. Secondly, it appears that even with a strong carbon price push, electro-fuels will not be adopted based on a purely economic decision due to their higher costs compared to biofuels. The situation will likely change when lifecycle GHG emissions are adopted and used as a reference to calculate the economic benefit of using low-carbon fuels. Indeed, in this model, biofuels and electrofuels both provide zero onboard emissions, while in a cradle-to-grave perspective, the additional emission reductions provided by electrofuels may balance their higher cost compared to biofuels, including bio-LNG. The presence of electrofuels will, in this way, help to solve the issues of biofuel availability. Lastly, the cost of biofuels from gasification is typically higher compared to bio-LNG from biogas upgrading. Therefore, the latter appears as a more profitable fuel choice, provided that future production capacity will be able to meet the demand.

Table 7.7 – Estimated world fleet emissions in 2050 for different scenarios and carbon prices, compared to GHG emission targets

Scenario	CO_2 price ($/ton)	Fleet GHG emissions in 2050 (Mtons/year)	GHG emission target in 2050 (Mtons/year)
SSP5	>145	1026	350
SSP5	>235	438	
SSP1	>145	767	
SSP5	>235	350	

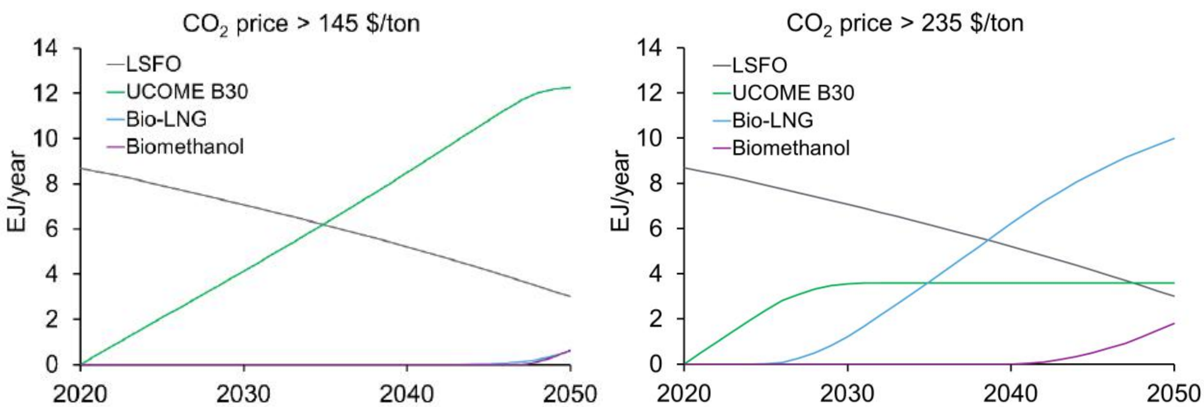


Figure 7.10 - Estimated fuel demand in SSP5 at different CO_2 prices

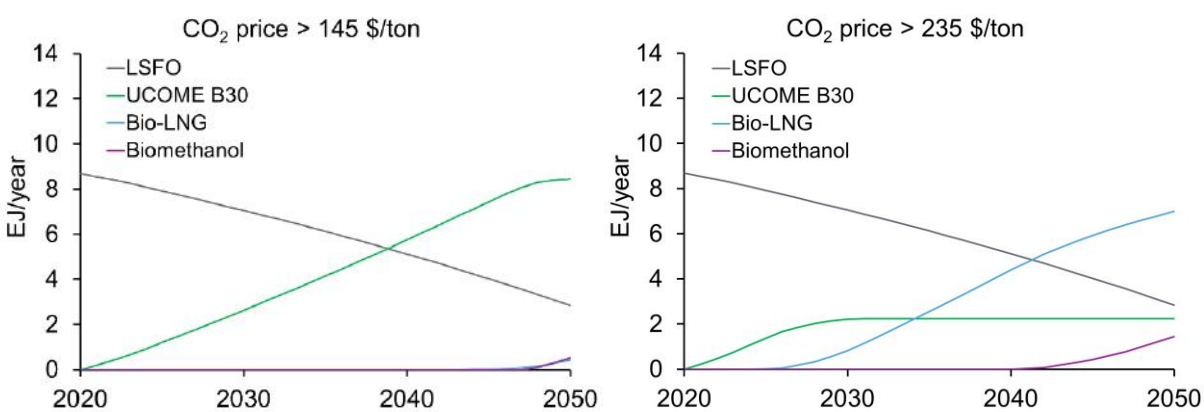


Figure 7.11 - Estimated fuel demand in SSP1 at different CO_2 prices

8. Bio-LNG fuel landscape

In general, there has been an increasing number of government policies and measures in the past few years to reduce greenhouse gas emissions, improve energy efficiency and support the development and deployment of renewables and other clean energy technologies. Many countries have implemented blending mandates and targets for the use of biofuel. Figure 8.1 presents the global mapping of existing biofuel mandates. Biofuel mandates have been implemented in most European countries, North and South American countries, several Asia Pacific countries and some African countries. However, most of the biofuel mandates focus on the use of ethanol and biodiesel in land transport. Currently, no biomethane mandate exists in any single country. In the past few years, policies and measures have been emerging regarding promoting biomethane or biogas. Most of them happen in Europe, focusing on biomethane production technology, production capacity, and related infrastructure development. Such policies and measures focus on biogas production for electricity generation rather than biomethane production for the transport industry.

Currently, Europe is the global leader in developing the biogas and biomethane industry. The region has the highest biogas production and upgrading plants and the largest installed capacity for generating raw biogas and purifying it for biomethane. According to BCC Research [157], as of 2019, 86.7% of biogas upgrading plants are located in Europe, followed by North America (8.9%) and Asia (3.6%). Despite having the second-highest number of biogas upgrading plants, North America's biomethane production experience has focused on landfill gas upgrading. The produced biomethane is mainly used y for electricity generation or limited usage in land transport. Besides Europe and North America, the biomethane industry is just beginning to emerge in the rest of the world, including Asia.

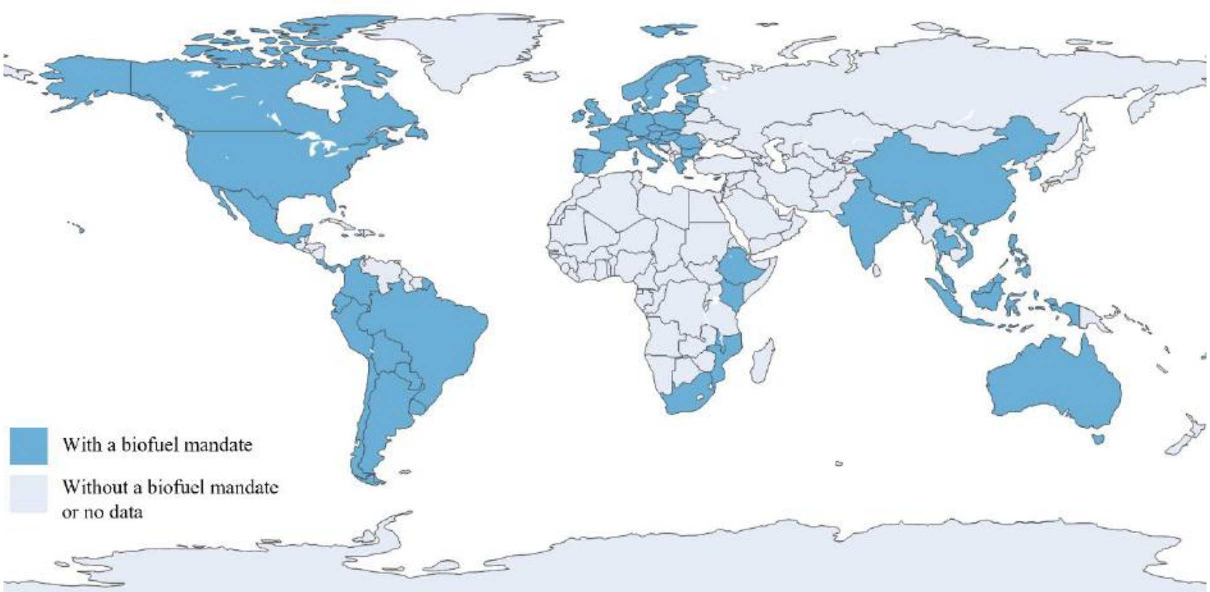


Figure 8.1 - Mapping of existing biofuel mandates. Data source: [157].

8.1. Regulatory framework

This section introduces the key regulatory framework and recent development related to biogas and biomethane in three selected areas and institutions: Europe, the United States, and the International Maritime Organization. Table 8.2 summarises the key regulations and recent development related to biomethane in these three entities.

8.1.1. Europe

The Renewable Energy Directive (RED) enforced in 2009 forms the basis of EU regulations on biofuels. The RED sets a mandatory 20% renewables target for the EU energy mix by 2020 and a 10% renewable energy target specific for transportation. In 2018, the European Union adopted the new RED (RED II), Directive 2018/2001, which entered into force on January 1, 2021. The RED II increases the mandatory 20% renewables target to at least 32% by 2030 with a 14% target for the transport sector, with a clause for a possible upwards revision by 2023. Besides the overall targets for using renewable energy, RED also includes specific sections related to biogas and biomethane. Article 12 of the directive mentions biogas's importance and high GHG mitigation potential. Article 16 provides non-discriminatory transport and distribution charges for gas produced from renewable sources. In addition, the directive also enables double counting of the biomethane made from waste in the renewable energy target for the transport sector.

More recently, the European Green Deal, a set of policy initiatives, was approved in 2020 to make European Union (EU) climate neutral by 2050. The European Green Deal includes two key initiatives: European climate law and the 'Fit for 55' package. The European climate law is a legally binding regulation to reach climate neutrality by 2050. By adopting it, the EU and its member states have to reduce net greenhouse gas emissions by at least 55% by 2030, compared to 1990. The 'Fit for 55' package is a set of proposals to revise climate-, energy- and transport-related legislation and implement new initiatives to support the European Green Deal. Under the 'Fit for 55' package, the European Commission is considering legislation specific to sustainable maritime fuels, the FuelEU Maritime regulation. This proposed regulation may set increasingly stringent limits on the carbon intensity of vessels visiting the EU starting from 2025. As a result, vessels under this regulation will have to adopt alternative fuels that could meet the requirement. As such, the implementation of the FuelEU Maritime could give a significant boost in the use of alternative fuels such as biomethane.

According to the most recent update on the EU regulations (Proposal for a Regulation of the European Parliament and of the Council on the use of renewable and low-carbon fuels in maritime transport and amending Directive 2009/16/EC – General approach), an obligation for the uptake of low carbon fuels such as bio-LNG will be introduced, with a penalty for shipowners proportional to the missed compliance with set reduction targets.

Table 8.1 – Estimated values for carbon intensity limits in EU according to the proposed FuelEU Maritime regulation (baseline for average ship carbon intensity in 2020 was set equal to 86 gCO_2eq/MJ, reference value for fuel oil)

Year	Reduction target	Carbon intensity limit (gCO_2eq/MJ)
2025	2%	89
2030	6%	86
2035	13%	79
2040	26%	67
2045	59%	37
2050	75%	23

Considering a baseline value of 91 gCO_2eq/MJ for the average onboard carbon intensity of ships in 2020 as a typical value for fuel oil, the reduction targets and the corresponding maximum carbon intensity allowed onboard ships are shown in Table 8.1. However, these limits are most likely not sufficient to satisfy the 2030 IMO's targets of a 40% reduction of emissions per unit of transport work and might soon be revised. According to such limits, the adoption of fossil LNG only would be sufficient to meet the targets until 2040. The issue of the final regulation is expected by the end of 2022.

8.1.2. North America

In the US, the Renewable Fuel Standard (RFS) is the primary federal policy supporting the use of biofuels. The RFS originated based on the Energy Policy Act in 2005 and was subsequently extended by the Energy Independence and Security Act of 2007. The RFS requires a biofuel target of an annual production rate of 36 billion gallons by 2022. In June 2022, the US Environmental Protection Agency (EPA) released the revised final volumes for Renewable Fuel Standards Program 2022. The final volumes have been reduced from 36 billion gallons to 0.63 billion gallons of cellulosic biofuel, 5.63 billion gallons of advanced biofuel, 20.63 billion gallons of total renewable fuel, and 2.76 billion gallons of biomass-based diesel fuel [158]. Besides the federal policies, Low Carbon Fuel Standard (LCFS) has been implemented in the states of California and Oregon. The LCFS promotes renewable natural gas as a transportation fuel by generating credits that can be sold to offset mandated carbon intensity deficits annually.

In Canada, energy policies that support the use of biogas and biomethane are usually happening at the provincial level. British Columbia, Ontario, and Alberta are the leading provinces that have already established the feed-in tariff for biogas production. The credit system available in the US has also been adopted in several Canadian provinces. For example, fuel suppliers in British Columbia are able to earn credits through trading fuels below certain carbon intensity based on British Columbia's Low Carbon Fuel Standard.

However, unlike the EU, the incentives for biogas upgrading that are present in European countries are generally not available in North America. There is also a lack of federal or country-level programs or incentives directly aiming to increase biomethane investments. The existing incentives, such as Renewable Identification Numbers (RINs) under RFS and LCFS credits, generally relate to road vehicles and renewable energy sources. The RFS policies and feed-in tariff in Canada also favour the use of biogas for direct electricity production. According to the BCC research [159], 85% of current biogas in the US is used to generate onsite electricity. Upgrading the biogas into biomethane and later injected into the national grid is generally not preferred.

8.1.3. International Maritime Organization (IMO)

In 2018, IMO adopted the "Initial IMO Strategy on Reduction of GHG Emissions from Ships". Based on the Initial Strategy, further energy efficiency design index (EEDI) phases were implemented. Various levels of emission targets have been set. Specifically, IMO commits to reducing CO_2 emissions per transport work by at least 40% by 2030 and 70% by 2050. It also set a target to reduce GHG emissions from international shipping by at least 50% by 2050 compared to 2008. During MEPC 73 in 2018, the time for developing the revised Strategy was set to be adopted in 2023 during MEPC 80. IMO does not have a specific view on bio-LNG but views biofuels as suitable for the existing fleet due to their drop-in capability to be blended with conventional marine fuels [160].

Table 8.2 - Key regulations and recent development related to biomethane in the EU, US and IMO

	EU	**North America**	**IMO**
Main Regulatory Framework	• The Renewable Energy Directive (RED) & RED II	•US: Renewable Fuel Standard (RFS) •Canada: provincial regulations	•Initial Strategy on the reduction of GHG emissions
Year of First Enforcement	•RED (2009) •RED II (2021)	•US: Energy Policy Act (2005) and Energy Independence and Security Act (2007)	•MEPC 72 (2018)
Key Highlights	•Specify the importance of biogas also related to biomethane production •Non-discriminatory transport and distribution charges for gas produced from renewable sources •10% of transport fuels to be derived from renewable sources by 2020 (RED) •Renewable energy target of at least 32% by 2030 with a 14% target for the transport sector (RED II)	•Biofuel targets to an annual production rate of 36 billion gallons by 2022 (US RFS) •Support direct electricity production from biogas •Promotion of corn ethanol and biodiesel from plant oils or grease •Incentive through credit trading •No programs or incentives directly aiming at increasing investments in biomethane	•New EEDI and CII •Total annual GHG emissions from international shipping should be reduced by at least 50% by 2050 compared to 2008 •Revised Strategy – set to be adopted in 2023 •To reduce CO_2 emissions per transport work by at least 40% by 2030, towards 70% by 2050, compared to 2008
Recent Developments	European Green Deal (2020) •European climate law (2020) •'Fit for 55' package (2021) •Proposed FuelEU Maritime initiative (2021)	•The new US climate goal (2021) aims to reduce net GHG emissions by 50%-52% below 2005 levels by 2030 •RFS Annual Final Rule 2022	•MEPC 76 More guidelines for EEXI and CII Implementation •MEPC 77 Agreement on the need to review and update the IMO GHG Strategy •Proposed MEPC 80 in 2023: Finalisation of an updated Strategy •Working group discussion on LCA

However, biofuels should be produced from sustainable feedstocks and energy supplies. There are other considerations, such as the availability of biofuels. More recent works in IMO, such as MEPC76 and MEPC77, have been focusing on detailing the guidelines for the Initial IMO Strategy. Examples are guidelines for EEXI and CII and guidance for Reporting EEDI Values to IMO. IMO is also discussing adopting the well-to-wheel approach with relevant guidelines and standards for ship's emissions.

8.2. Regulatory challenges

This study identified two key regulatory challenges that may hinder the large-scale development and usage of biomethane for the shipping industry. First, there is a lack of commonly accepted standards for grid injection and vehicle fuel. Few biomethane standards exist but mainly at a national level. Technical specifications on the biogas quality requirements also vary across countries and regions. For example, although the EU allows for non-discriminatory access to the gas grid based on the RED, the biogas still has to meet the pipeline quality before grid injection. Some countries still prohibit grid injection of biomethane produced from certain feedstocks, such as municipal solid waste and sewage. Efforts on standardisation among countries and regions are needed to make biomethane competitive and reliable in the marketplace. Another key regulatory challenge is the development of commonly accepted and preferably legally binding certificates of origin specific to biomethane. The existing Energy Attribute Certificate (EAC) system has been designed for renewable electricity. In the US, such an EAC system is usually referred to as the Renewable Energy Certificates (RECs). In Europe, it is known as Guarantees of Origin (GOs). RECs and GOs can prove that electricity comes from a renewable source. An equivalent version of GOs for green gas is often called Green Gas Certificates or Renewable Gas Guarantees of Origin (RGGOs). RGGOs are usually associated with green gas injected into the national grid to track the green gas through the supply chain to provide certainty for consumers. However, there is a lack of a harmonised green certification system that hinders the smooth cross-border trading of the RGGOs. For example, some European countries have national registry certification bodies, but these national renewable gas standards vary. Voluntary schemes exist, such as the European Renewable Gas Registry (ERGaR), as cooperation between established national renewable gas registries in Europe. However, no harmonised EU legislative body currently regulates European green gas certificates.

8.3. Addressing barriers: recommended actions

Bio-LNG can be a viable marine fuel to decarbonise the shipping sector, both as drop-in and stand-alone fuel, provided that key challenges will be overcome to make its use onboard ships possible. There are technical, logistic and regulatory barriers since biomethane production and use are not widespread yet. However, since this fuel is recognised as one of the most valid candidates for future decarbonisation of heat and power across many sectors, such barriers may be overcome sooner than other fuels. An overview of the main actions that need to be taken to foster the use of this fuel in shipping is summarised in Table 8.3.

One of the main issues that need to be addressed as soon as possible across the world regions is related to the small production capacity that needs to increase substantially to meet the global demand. Building new plants is currently slow and can take years, and there is not enough awareness among biomass suppliers about the economic potential behind waste biomass. Targeted planning and dedicated policies at the national level are essential for efficient waste collection from agricultural, forestry and animal industries. While the anaerobic digestion route is mature and needs only scale-up, gasification and methanation technologies that could enable centralised production of biomethane still need more investment for research and technology demonstration to become viable solutions. Since biomass gasification can be used to produce a variety of fuels, a push from other sectors may allow this technology to become mature in the medium-long term.

The analysis of logistic issues explained in chapter 6 showed that the liquefaction of biomethane to obtain bio-LNG is more economically convenient when performed in centralised liquefaction plants (existing or new), but this requires injection of biomethane into the existing gas network. Establishing certification systems for renewable gas trading is key to enabling efficient biomethane transport across the globe. Regarding the onboard use of bio-LNG, there are fewer barriers compared to other alternative fuels since LNG is already a mature fuel, and there is extensive knowledge about bunkering and combustion of methane on ships. However, engine manufacturers must keep improving combustion performances to reduce methane slip which has a significant impact on the lifecycle emissions. Appropriate guidelines for blending and an international regulatory scheme to define the amount of GHG savings that can be achieved by using bio-LNG are other important factors that can help improve trust among shipowners looking at bio-LNG to replace fossil fuels in their operations.

Table 8.3 – Recommended actions to overcome technical, logistic and regulatory barriers to bio-LNG use in shipping

	Technical and logistic actions	Regulatory actions
Production	**Anaerobic digestion:** • reduce methane losses from biogas production and upgrading • focus on closed digestate storage and fugitive methane recovery • building new plants on a large scale • establishment of robust waste biomass supply chains • improve digester productivity **Gasification:** • improve gas cleaning technologies • reduce production costs • more research on alternative gasification technologies • scale-up required for gasification and methanation plants	• national policies schemes required to support a quick scale-up of large-scale biomethane production plants and their biomass supply chains • incentivisation of demonstration projects for large biomass-to-SNG plants • foster the collection and use of existing streams of waste biomass from agricultural activities and MSW and sewage from cities • develop awareness among farmers for the mobilisation of agricultural and forestry wastes • guidelines, piloting, and support incentives for sustainable sequential cropping
Transport	• avoid the use of dedicated bio-LNG supply chains for shipping (high costs) • prefer transport of biomethane by pipeline in gaseous form rather than by truck and ship in liquefied form • build new biomethane plants in a strategic position (close to ports and gas liquefaction hubs or gas network injection points) • address fugitive methane losses across the value chain	• establishment of intranational and international schemes to foster biomethane trading across borders • guarantees of origin system required to carry information about sustainability

	Technical and logistic actions	Regulatory actions
Use	• reduce methane slip onboard	• global policy framework to assess lifecycle emissions of biofuels in shipping and reduce uncertainties about the climate impact of bio-LNG • carbon pricing mechanisms to foster the use of alternative fuels • mandatory biofuel blends • improvement of current LNG bunkering and transport infrastructure • spread knowledge about bio-LNG among shipowners

9. Conclusions

This study aimed to assess the many uncertainties regarding the sustainability of bio-LNG as a fuel for the shipping industry by evaluating the key factors influencing future availability for the maritime sector, such as fuel cost, GHG emissions and the logistic issues related to the production, transport and use of liquefied biomethane onboard ships. Despite the high level of complexity of the analysis, some key outcomes were found based on both available literature and internal models.

9.1. Feedstock availability

The sustainable biomass feedstock potential from energy crops, agricultural residues, forestry residues and other biowaste materials for bio-LNG production in 2030 and 2050 is theoretically sufficient to support the shipping industry fully. However, it is limited by competitive uses from other sectors such as paper and material use of biomass, aviation, specific heat applications in industry, power generation and heavy-duty road transport. Just like shipping, these sectors will compete for the available 2nd generation biomass feedstock that will soon become the main sustainable source of biomass for energy purposes. Shipping was found to be a medium-priority sector, and it is, therefore, unrealistic to think that bio-LNG could fully cover the future energy demand for shipping fuels. The amount of biomethane that could be available for the maritime sector is subjected to many uncertainties regarding future demand for biomethane from all sectors, production scale-up and biomass conversion technology maturity. The anaerobic digestion pathway will likely remain the preferable choice due to high technology maturity, reliability on sustainable feedstock and lower production costs compared to other production pathways. This study assumes that with the application of proper policies to boost worldwide biomethane production and, provided enough awareness is raised among stakeholders in the shipping sector, bio-LNG could be readily available at many ports in the next decades and will be able to cover a significant fraction of the future fleet energy demand: up to 0.4-3.1% in 2030 and 2.4-12.6% in 2050. This is valid if the use of pure bio-LNG to fuel ships is assumed, however when considering it as a drop-in fuel for blending with fossil LNG, the potential energy demand coverage increases: up to 15.7% and 62.9% of the total energy demand in 2030 and 2050, respectively, with 20% blending rate.

9.2. Costs

The estimated cost of bio-LNG from biogas upgrading today stands around 19-37 $/GJ, 3-4 times the cost of bunker LNG price from fossil sources. Bio-LNG cost to the shipowner depends mostly on the biomethane production cost, which represents around 70% of the final cost. Biomethane cost ultimately depends on the conversion technology adopted and on the biomass feedstock used in the process. The final bio-LNG price is also influenced by the variabilities of logistic costs that also affect fossil LNG bunker prices. Bio-LNG from thermal gasification would cost even more today. However, if the technology is extensively deployed in the following decades, in 2050, the cost of biomethane from gasification could match the current costs of biomethane from anaerobic digestion of biomass. The cost decrease expected in 2030 and 2050, mostly due to production scale-up and improved logistics, will reduce the final bio-LNG price but will not be enough to make it competitive with fossil LNG, based on historical prices. In 2030 the expected cost of bio-LNG bunker fuel is around three times the cost of its fossil counterpart, with an average value of 25 $/GJ, while in 2050, it will decrease even more and reach an average of 20 $/GJ.

The analysis showed that even in the best scenario, the bio-LNG cost is substantially higher compared to fossil LNG. This means that its economic competitiveness will ultimately depend on subsidies for biofuels and carbon pricing schemes. With current prices, a very high carbon levy would be required to make bio-LNG competitive with fossil LNG. However, if manure is used to produce biomethane and if avoided methane emissions are considered, the required carbon price will decrease.

Despite its relatively high cost, bio-LNG emerges as a future-proof candidate fuel for decarbonising shipping compared to other alternative fuels. Indeed, it is generally cheaper than biomethanol produced from thermal gasification of biomass and may soon be competitive with sustainable biodiesel (i.e. produced from non-edible sources), which has a relatively low price but suffers from low availability issues.

9.3. Emissions

The study highlighted the high level of uncertainty regarding the evaluation of greenhouse gas emissions associated with the production, transport and use of bio-LNG as a shipping fuel. The main method to define the GHG emissions of marine fuels is the lifecycle analysis (LCA), which requires a massive set of assumptions that may lead to substantially different results. Since the available literature shows a massive range for the GHG emissions of biomethane as fuel, a dedicated model was created with SimaPro LCA software in order to spotlight the main factors influencing the final results. It was found that the main sources of equivalent CO_2 emissions in the bio-LNG value chain are related to the fugitive emissions of methane from the anaerobic digestion process (in particular from the storage of the digestate and biogas upgrading step) and onboard methane slip from the engine. If such emissions are not adequately addressed, the advantages of using waste biomass to produce bio-LNG are soon overcome by the strong greenhouse gas effect of methane that leaks across the value chain. However, if proper measures are taken to minimise methane leakage in the biomethane production process and if methane slip onboard is avoided or minimised, bio-LNG could provide substantial GHG emissions reduction (43-72%) compared to the fuel oil baseline. This makes bio-LNG a practical choice for the decarbonisation of shipping. However, it shows slightly lower environmental performance when compared with biofuels from gasification (e.g. biomethanol) and electrofuels such as e-ammonia and e-LNG.

When manure is used as feedstock to produce bio-LNG, avoided emissions from the natural decomposition of manure on fields (which is the standard practice) could be considered. This may lead to negative values of GHG emissions. However, this option must be carefully evaluated as different assumptions on the degradation rate of manure and its alternative uses can lead to very different values of CO_2 emissions per unit of fuel energy as its influence on the final result is of an order of magnitude higher compared to other components of the LCA. Nevertheless, this is a key factor that contributes to the attractiveness of bio-LNG as a future fuel for shipping. If bio-LNG is used as drop-in fuel and thus blended with fossil LNG, relatively low blending rates can help achieve intermediate emission reduction targets: a 30% blend can provide up to 26-38% emission reduction compared with the fuel oil baseline and up to 46-59% if avoided emissions from manure are included.

9.4. Logistics

The value chain of bunker bio-LNG differs from that of fossil LNG as it requires biomass supply chains for biomethane production plants and transporting gas to the bunkering hubs. Part of this value chain can overlap with existing infrastructure for natural gas, which reduces logistic costs. The analysis shows that a proper size of future biomethane plants must be defined in order to avoid high costs due to the collection and transport of biomass to the production plant. Decentralised and centralised configurations both offer pros and cons, and an intermediate solution between the two might be the most viable choice to limit the cost of biomethane at the plant gate. The best scenario is represented by medium size plants strategically located close to farms and biomass waste collection points, such as cities for food waste and slurry, animal farms for manure and agricultural sites for residues. Lower costs are achieved when biomethane is injected into the gas grid and transported to liquefaction plants and LNG terminals using the existing infrastructure, while the most efficient solution involves the complete conversion of biogas and biomethane into LNG through certificates. However, this would require a proper regulatory framework and green certificates for renewable gas trading inside and across borders, as it already happens for green electricity in some regions of the world (i.e. Europe). Dedicated supply chains for shipping, involving on-site liquefaction and transport of bio-LNG by dedicated trucks and bulk carriers, are appropriate for demonstration purposes. However, they should be avoided from a large-scale implementation perspective due to the very high costs.

9.5. Bio-LNG adoption

Bio-LNG is competitive in terms of costs and GHG emissions savings compared to other existing alternatives such as biomethanol and electrofuels like e-ammonia, renewable methanol and e-LNG. Bio-LNG from anaerobic digestion of waste biomass, and especially from manure, represents an attractive choice for shipowners due to the fact that the fuel cost is lower than other alternative fuels, and the onboard energy conversion technology is mature and well-understood, with existing guidelines and established practices. Moreover, there is a current (and developing) infrastructure for transport and bunkering, and the presence of an existing fleet of vessels currently running on fossil LNG represents a starting market for the adoption of bio-LNG, especially as a drop-in fuel. This is not the case for other alternatives like methanol and ammonia. The main barriers to its widespread adoption are related to fuel availability and to the current absence of proper regulations for assessing the lifecycle GHG emissions that may vary substantially depending on biomass feedstock and fuel production technology. However, these issues are not unique to bio-LNG and affect other biofuels. Since e-LNG appears to have cost and emission performances similar to other electrofuels, it could gradually replace bio-LNG in the long term when the demand for alternative low-carbon fuels increases and the price of hydrogen decreases. E-ammonia is one of the most competitive choices among the electrofuels as its production does not require CO_2 (which is an added cost for renewable methanol and e-LNG), however many uncertainties related to the combustion technology, the onboard emissions and safety issues still have to be addressed.

9.6. Regulations and barriers

Although many forecast a widespread use of biomethane in the future to decarbonise several sectors, there is still a lack of specific regulations and policies aimed at developing the production and use of this renewable gas around the world. It is, however, likely that, in the upcoming years, more and more national and international policies will be issued to foster the use of biomethane in heating, power generation and transport sectors. Some general guidelines already exist for drop-in biodiesels in shipping, and more specific policies for other kinds of biofuels may soon be issued. IMO does not have a specific view on bio-LNG, but it views biofuels in general as a suitable option for the existing fleet due to their drop-in capability to be blended with conventional marine fuels. This report shows that bio-LNG has all the required characteristics to fit the biofuels that could help to achieve future climate goals. European RED II directive, adopted in 2018, mentioned the importance of biogas and biomethane related to their GHG mitigation potential. More recently, the FuelEU Maritime regulation proposal issued in the 2020 European Green Deal aimed at framing a set of policies to limit the carbon intensity of vessels travelling inside the Union, fostering the use of low-carbon alternative fuels. This could significantly boost the adoption of biomethane and bio-LNG for shipping.

The main barrier to the adoption of bio-LNG from a regulatory perspective is due to a lack of commonly accepted standards for biomethane production, grid injection and vehicle fuel usage. Few biomethane standards exist today and mostly at a national level. Technical specifications on the biogas quality requirements also vary across countries and regions. Efforts on standardisation among countries and regions are needed to make biomethane a competitive and reliable fuel in the marketplace. Another key regulatory challenge is the development of commonly accepted and legally binding certificates of origin for biomethane. There is currently no harmonised legislative body regulating green gas certificates across the world, however, based on the current views and forecasts from various international bodies such as IEA, Gas for Climate and ETC, it is expected that the role of biomethane in the future decarbonisation of the economy will soon be recognised as a priority and regulatory framework are likely to come in the near future, probably inside the European Union context first and later in other regions of the world.

9.7. Looking ahead

Just like it happened for fossil LNG in shipping, the widespread adoption of biomethane across several sectors and the existence and development of an integrated global transport infrastructure may be a significant boost for the shipping industry to use biomethane (in the form of bio-LNG), even though there will be competition from other sectors. Biomethane use in the transport sector, primarily for heavy-duty trucks and ships, will likely increase dramatically in the upcoming decades, and this will help to reduce the uncertainties and costs related to fuel production and transport. Carbon pricing schemes and a proper regulatory framework are currently lacking. However, they are essential for the adoption of bio-LNG as a shipping fuel. Nonetheless, bio-LNG has an advantage compared to other alternatives such as methanol, hydrogen and ammonia due to the available experience in transporting, bunkering and handling LNG in the shipping industry.

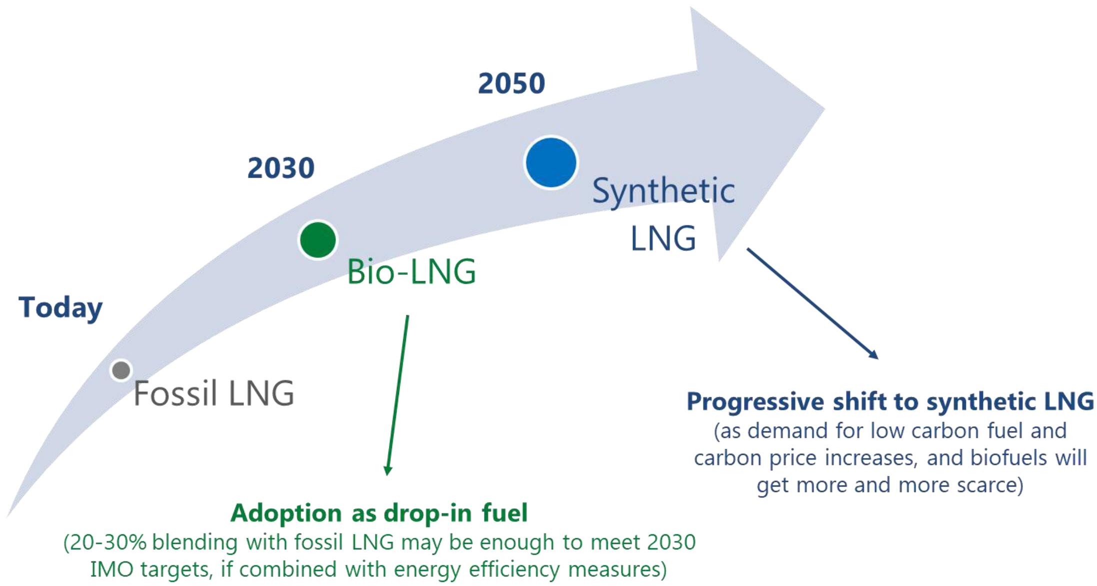


Figure 9.1 – Adoption pathway for bio-LNG and e-LNG in shipping

Even though there are still many uncertainties related to bio-LNG as shipping fuel, mostly due to the huge scale-up of worldwide biomethane production required in the next years and the need for proper supporting policies for biomethane production and trading, it is clear that shipowners should not overlook the application of this fuel for their future operations. Bio-LNG appears to be a reliable and future-proof fuel for decarbonisation of the shipping sector thanks to the readily available technology for fuel production and uses onboard and the competitive cost compared to other sustainable biofuels. Bio-LNG can be blended with fossil LNG in relatively small amounts to help reach the intermediate IMO targets, and the biofuel proportion in the mix can be increased to meet raising targets. However, it is unlikely that bio-LNG could fully support a large fleet of vessels in the distant future due to the limited global availability of biomass and the increasing demand for bioenergy from other sectors. Therefore, the shipowners that invested in this technology pathway will need to shift to e-LNG in the long term, which has the disadvantage of requiring CO_2 for its production. Thus, its cost will likely be slightly higher compared to non-carbon electrofuels (i.e. e-ammonia).

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