Availability and costs of liquefied bio- and synthetic methane

The maritime shipping perspective

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Content

Acronyms

Abbreviation	
AD	Anaerobic Digestion
AEC	Alkaline Electrolysis Cell
AHPD	Autogenerative High Pressure Digestion
CAPEX	Capital Expenditure
DAC	Direct air capture
EJ	Exajoule
FLH	Full load hours
FQD	Fuel Quality Directive (2009/30/EC)
GHG	Greenhouse Gas(es)
HFO	Heavy fuel oil
HGV	Heavy goods vehicle
HSH	Hot standby hours
ILUC	Indirect Land Use Change
km	Kilometre
kW	Kilowatt
kW_e	Kilowatt-electric
kW_{th}	Kilowatt-thermal
kWh	Kilowatt hour
LBM	Liquefied biomethane
LNG	Liquefied natural gas
LSM	Liquefied synthetic methane
MEPC	Marine Environment Protection Committee
MEUR	Million Euro
MGO	Marine Gas Oil
MMBtu	million British thermal units
mt	Metric ton
Mt	Megaton
MW	Megawatt
MW_e	Megawatt-electric
MW_{th}	Megawatt-thermal
MWh	Megawatt hour
NG	Natural gas
OPEX	Operational Expenditures
PEM	Proton Exchange Membrane
PtG	Power to Gas
RED	Renewable Energie Directive (2009/28/EC)
RED II	Revised Renewable Energy Directive (2018/2001/EU)
SOEC	Solid Oxide Electrolyser Cell
TPH	Thermal Pressure Hydrolysis (TPH)
TRL	Technology Readiness Level
TWh	Terawatt hour
VLSFO	Very low sulphur foil oil

Executive Summary

Currently, a small, but growing number of ships are LNG-fuelled. This is mainly due to stricter air pollution regulation for maritime shipping. Decarbonisation of the maritime shipping sector requires the use of zero/low carbon fuels and the use of liquefied biomethane (LBM) or liquefied synthetic methane (LSM) is a potential decarbonisation pathway for shipping. LNG-fuelled ships could then use LBM or LSM without major modifications and a technically mature LNG infrastructure would only need to be scaled up. The volumes of LBM and LSM that will become available to the shipping industry and the relative costs of these fuels compared to other zero/low carbon fuels are crucial for the viability of this pathway.

Against this background, this study aims:
— to assess the global availability of LBM and LSM in relation to the global energy demand of maritime shipping;
— to assess the cost price of LBM and LSM and to compare it with the cost (price) of other existing and potential marine bunker fuels; and
— to make recommendations as to how industry and policy makers could address barriers to the scaling of LBM and LSM as a marine fuel.

The study focuses on 2030 and 2050, years in which important milestones in the IMO Initial Strategy on Reduction of GHG Emissions will have to be met.

The study is based on review of scientific and grey i.e. non-academic literature.

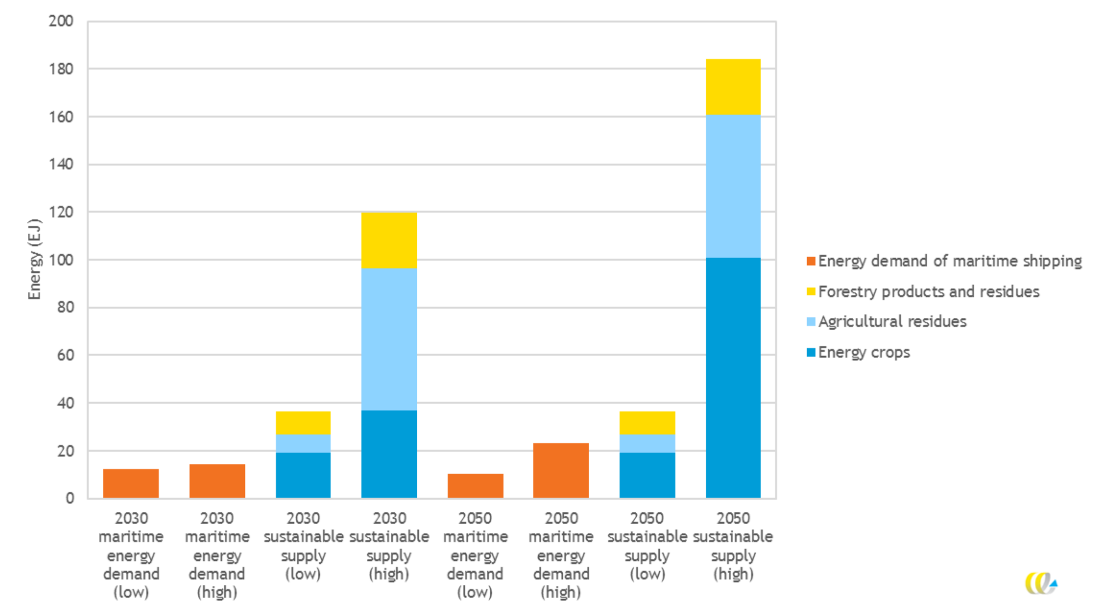
Availability of biomethane

Biomethane can be made from different types of biomass and by means of different conversion technologies. Conducting a literature review, this study has analysed the maximum conceivable sustainable supply of the following biomass streams:
— energy crops (grown solely for energy purposes);
— agricultural residues;
— forestry products and residues; and
— aquatic biomass.

The maximum conceivable sustainable supply is defined as the maximum supply that can be produced in a sustainable way. Different literature sources apply different definitions of sustainability. Most have in common that they rule out biomass streams, interfering with the growth of food, fodder and fibres.

Taking into account the efficiency of the different production routes and of liquefaction, Figure 1 compares the maximum conceivable sustainable supply of LBM with the projected energy demand from the maritime sector in 2030 and 2050. The maximum conceivable sustainable biomethane potential is expected to range from roughly 40 to 120 EJ in 2030 and from roughly 40 to 180 EJ in 2050, compared with projected energy demand from shipping of 12-14 EJ in 2030 and 10-23 EJ in 2050. In addition to the biomass streams depicted in Figure 1, aquatic biomass has the potential to play a dominant role, especially in 2050 (550–1,300 EJ biomethane). However, only a few studies have looked into the global availability of aquatic biomass so far and it is not possible to draw firm conclusions on its maximum sustainable supply.

Figure 1 — Maritime energy demand and global maximum sustainable supply of LBM in 2030 and 2050, without aquatic biomass (EJ)



From this analysis, we can conclude that, if the global maximum conceivable supply of biomass were converted into biomethane, and if all the biomethane became available for maritime shipping, it would be more than sufficient to meet the global total energy demand of the sector. The sustainable potential could be substantially higher in 2050 compared to 2030, however, there is no consensus on this in the literature.

Regional availability of biomass

It is difficult to compare estimates of the global distribution of biomass feedstocks as studies use different regional boundaries and sets of biomass categories. At a high level, the literature appears to show that the global sustainable biomass potential that could be used to produce LBM is widely distributed with a quarter to a third located in Asia and OECD regions contributing 25 to 55% to the total. The biomass distribution over the different regions varies between different types of biomass.

Availability of synthetic methane

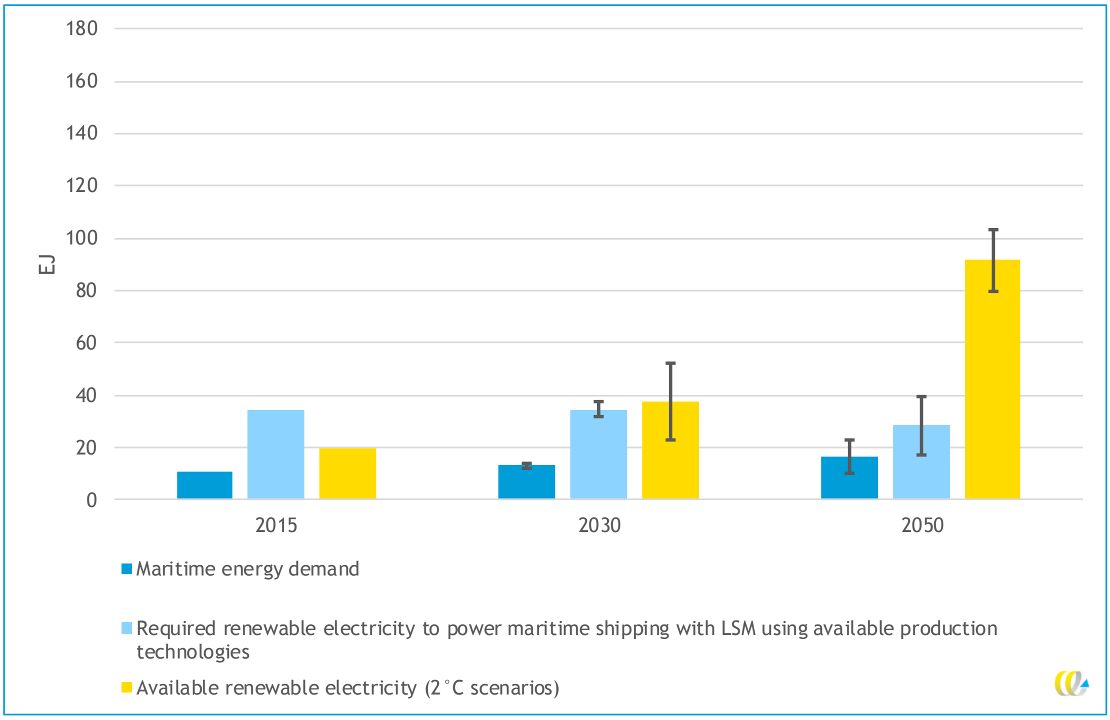
We define synthetic methane as methane that is derived from the synthesis of CO_2 and hydrogen (methanation process). For synthetic methane to be considered a zero emission fuel, the hydrogen would have to stem from water electrolysis, using water and renewable electricity as inputs; the CO_2 would have to be ‘recycled CO_2’ and could be captured from industry flue gas or from air.

The availability of synthetic methane is mainly determined by the availability of technologies; because the plants do not require arable land, land availability is less of a constraint.

Water electrolysis and methanation are well-established processes. Carbon capture at the stack of an industrial plant is also a well-established process. In the long-run, direct air capture (DAC) and carbon capture at the stack of bioenergy production plants are more relevant options. Renewable electricity technologies are mature, with the efficiency of some technologies expected to further increase in the future. Hence, all technological processes that are required to produce synthetic methane can be considered to be mature or near maturity.

Figure 2 shows the energy demand from maritime transport and the amount of renewable electricity that would be required to meet this demand with LSM. Because of projected improvements in the production process, the renewable electricity demand will decrease when the projected energy demand increases. The amount of renewable electricity required to produce LSM for the maritime sector is compared with the projected amount of renewable electricity that will be required to limit global warming to 2 degrees above pre-industrial levels. In 2050, an estimated 25-30% of renewable electricity would need to be produced in addition to the projected amount to decarbonise the maritime transport sector using LSM.

Figure 2 — Maximum potential supply of LSM compared with maritime energy demand given a renewable electricity supply in line with a 2°C degree scenario



From this analysis we can conclude that the current global share of renewable electricity is insufficient to produce sufficient LSM to power a significant share of the fleet. The situation is projected to improve, although the investments require adequate policies. And it remains to be seen how much of the renewable electricity will be available for the production of hydrogen which is a necessary feedstock for all synthetic fuels such as LSM, green hydrogen and ammonia.

Discussion of availability for and demand of shipping sector

The analysis of the availability of LBM has focused on the global maximum conceivable supply and the analysis of the availability of LSM on the renewable electricity required to supply the entire shipping sector with LSM.

It would however be unrealistic to assume that these volumes of LBM/LSM would all become available to the shipping sector: Biomass that can be used for the production of LBM could be utilised in alternative ways, i.e. either used directly or for production of other gaseous or liquid biofuels and hydrogen. And the renewable electricity used for the production of LSM could also be used differently, i.e. either used directly or for the production of other synthetic gaseous or liquid fuels.

Currently, most natural gas is used in the power sector, industry and the built environment. It can be expected that the power sector and industry will reduce their demand for methane when the economy moves away from fossil fuels. The built environment, land-based, HGV transport and shipping may see a continued or an increased demand for methane from renewable sources.

In order to scale up the use of LSM and LBM in the shipping sector, it could be relevant to reduce the uncertainty about the use of methane as a fuel, especially with regards to methane slip and the associated climate impact. Policy measures like a fossil carbon levy, emissions trading or a low-carbon fuel standard could be implemented to shift the demand in the shipping sector from natural gas or liquid fossil fuels to LSM, LBM or other low- and zero-carbon fuels.

(Relative) costs of biomethane and synthetic methane

The literature review of the cost price of biomethane and synthetic methane at the plant gate i.e. production costs including input costs, produced the following findings (all figures in USD_{2019}):

Biomethane costs

As Table 1 shows, the current cost price of biomethane from anaerobic digestion is estimated to lie in the range of around 20 to 50 USD/MMBtu and to be lower than for gasification (range of around 25-65 USD/MMBtu). For both processes, production costs are expected to be lower in 2050, with the costs for gasification then being lower than for anaerobic digestion. However, only limited research has been carried out for the 2050 situation. Future cost reductions will most likely be the result of upscaling and the further development of gasification technologies. Costs can also decrease if fewer energy crops and manure and more tertiary residues like organic waste and sludge could be used.

Table 1 — Summary of biomethane cost price values at the plant gate from the literature review

[USD/MMBtu]	Anaerobic digestion	Gasification
Current situation	19-49	24-63
2050	15-21	13

Synthetic methane costs

The estimations of the cost price of synthetic methane vary significantly: for 2030 around 23-110 USD/MMBtu and for 2050 around 15-60 USD/MMBtu. Different assumptions regarding the price of renewable electricity and the load of the electrolyser are the main reasons for this large range. Renewable electricity prices play a major role for the cost price of synthetic methane. These factors also hold for the production of green hydrogen and other synthetic fuels such as ammonia.

Cost comparisons with alternative bunker fuels

Two comparisons between the costs of alternative bunker fuels have been conducted in the study. Since data availability for 2050 is rather poor, these comparisons focus on 2030. First, the expected bunker fuel prices of fossil fuels (VLSFO, fossil LNG) and the expected cost price of two post-fossil fuels (LSM, LBM) at point of delivery in port have been compared. Regarding the fossil bunker fuels, a carbon mark-up has been accounted for, assuming that an according climate policy measure will be in force in 2030.

This first cost comparison shows:
- Per energy unit, fossil LNG would be the cheapest and LSM the most expensive bunker fuel in 2030. Fossil LNG is estimated to be between 1 to 11 USD/MMBtu cheaper than VLSFO. LSM can only be cheaper than LBM, if cheap renewable electricity is available and high electrolyser load factors can be achieved.
- A carbon mark-up of between 50–100 USD/t CO_2, the 2030 carbon price level that is considered consistent with achieving the Paris temperature target, will not be sufficient to incentivize a switch from fossil LNG to LBM or LSM in 2030. However, a 2050 carbon price that is consistent with a well below 2°C mitigation pathway i.e. between 300 and 400 USD/t CO_2, can be expected to incentivize a switch from fossil LNG to LBM, at least if the 2050 price for fossil LNG is not below its 2030 price.

Second, the cost price of different alternative, renewable fuels (liquid hydrogen, liquid ammonia, LSM, LBM) are compared at the plant gate (see Table 2) i.e. before any costs associated with transport, distribution and bunkering, which are still uncertain for hydrogen and ammonia, are taken into account.

Table 2 — 2030 plant gate cost price estimates for different renewable bunker fuels

	Cost price at plant gate (USD/MMBtu)
LBM	21-48
LSM	26-113
Liquid ammonia	17-105
Liquid hydrogen	19-72

From this second cost comparison we can conclude the following:
- In an optimistic scenario (lower range of the cost estimates from the literature review),
  - plant gate costs are broadly comparable for LBM, liquid ammonia and liquid hydrogen;
  - plant gate costs of liquid ammonia are expected to be lowest, followed by liquid hydrogen and LBM with LSM featuring the highest costs. Significantly lower liquefaction costs for ammonia can explain the cost differential between liquid

ammonia and liquid hydrogen, but the presumed optimistic electricity price might also vary between the estimates.
- In a pessimistic scenario (higher range of cost estimates from the literature review), plant gate costs are expected to be lowest for LBM, followed by liquid hydrogen; costs for both, liquid ammonia and LSM are relatively high and highest for LSM.

The optimistic scenario will probably only materialise for liquid hydrogen, liquid ammonia and LSM if the production location has favourable conditions for renewable electricity. This may require the transportation of the produced fuels over longer distances, depending on the locations of the bunker ports.

If transported by ship, transportation costs can be expected to be lower for liquid ammonia compared to liquid hydrogen and LSM and indeed, LBM: due to ammonia's relatively high boiling point it can become liquid at relative low pressure and/or under relatively mild conditions. Liquefaction, storage and transport costs are therefore lower than for hydrogen and LSM/LBM; for liquid hydrogen these costs are can be expected to be higher than for LSM/LBM.

Since the production of LBM does not rely on the availability of cheap renewable electricity, this might allow for local production in the vicinity of major ports and could save out costs for the transport of the bunker fuel. Local production of LBM might however require transport of biomass. These transport costs can be expected to be relatively low, at least if the biomass can be transported/is available in bulk.

As the costs of the bunker infrastructure for hydrogen and ammonia are not known, their impact on the bunker fuel prices are difficult to assess at present. However, given that the bunkering infrastructure for LBM and LSM are technically mature and commercially available whereas the bunkering infrastructure for hydrogen and ammonia is technically still immature, the bunker price cost mark-up for the bunkering of hydrogen and ammonia can be expected to be higher than for LSM and LBM, at least in the short- and medium-run.

Conclusions

The future maximum conceivable sustainable supply of LBM and LSM exceeds the energy demand from the shipping sector, provided that biomass will be used to produce methane and sufficient investments are made in renewable electricity production. The production costs of these fuels need not be significantly higher and could be comparable to the production costs of other low- and zero-carbon fuels. So, if the costs of bunkering infrastructure and ships are comparable as well, LSM and LBM would be viable candidate fuels for a decarbonised shipping sector.

1 Introduction

1.1 Background

The current air quality requirements for ships in Emission Control Areas and the upcoming global cap on the sulphur content of fuel oil of 0.50% m/m provide an incentive to use liquefied natural gas (LNG) as marine bunker fuel. In consequence, the number of LNG-fuelled and LNG-ready ships[1] is currently[2] rising: according to Clarksons Research, around 525 LNG-capable ships are in the fleet and around 330 on order.

The Initial IMO Strategy on Reduction of GHG Emissions from Ships (Resolution MEPC.304(72)) aims to phase-out greenhouse gas emissions from international shipping as soon as possible in this century. In addition, the Strategy sets the ambitions to:

- improve the carbon intensity of shipping by at least 40% in 2030, relative to 2008 and pursue efforts to improve it by 70% by 2050; and
- reduce the greenhouse gas emissions of shipping by at least 50% in 2050, relative to 2008.

The Initial Strategy also notes that 'the global introduction of alternative fuels and/or energy sources for international shipping will be integral to achieve the overall ambition'. It is generally understood that these fuels and energy sources will contain significantly less/no fossil carbon compared to the bunker fuels currently used.

Given the IMO's Initial GHG Reduction Strategy, the question arises for how long LNG-fuelled ships and LNG bunker fuel infrastructure will be viable.

Whether an investment in an LNG-ready ship is profitable thereby depends on the total cost of ownership of the different possible combinations of propulsion systems and bunker fuels a ship owner has at hand, given the air quality regulations for maritime shipping and given that at a later point in time the ships might — depending on their life time — have to switch to renewable bunker fuel, either as a drop-in fuel or as a fuel that would require additional retrofits.

Liquefied bio- and synthetic methane[3] (LBM and LSM) could play an important role in this context since it could substitute fossil marine LNG[4]. The future availability of LBM and LSM as well as the cost prices of these fuels are therefore the focus of this study.

[1] LNG-ready ships can relatively easily be converted to LNG-capable ships.

[2] September 2019.

[3] Focus of the study are two types of low/zero carbon bunker fuels that can easily substitute the current marine LNG which we call 'liquefied bio-methane' and 'liquefied synthetic methane'. We decided not to work with the terms 'bio LNG' and 'synthetic LNG' to avoid the association with fossil natural gas.

[4] LNG is typically composed of methane, ethane, propane and nitrogen, with the composition depending on the origin of the natural gas. Main component is always methane with its share ranging from 80-99% (IGU, 2012). Using methane instead of LNG might require retrofits which we however expect to be minor.

1.2 Objective of study

The aim of the study is threefold:
1. To assess the availability of LBM and LSM in relation to the global energy demand of maritime shipping.
2. To assess the cost price of LBM and LSM and to compare it with the cost (price) of other existing and potential marine bunker fuels.
3. To give recommendations as to how industry and policy makers could address barriers to the scaling of LBM and LSM as a marine fuel.

1.3 Scope of study

The scope of the specific tasks are discussed in the according sections of the report; the general scope of the study is as follows:

Time horizon

We assume that the fleet will be required to, and will, meet the IMO targets as specified in the Initial IMO Strategy on Reduction of GHG Emissions from Ships. Specifically, we assume that the following targets will be met:
- by 2030 the fleet's carbon intensity is reduced by at least 40% relative to 2008;
- by 2050 the fleet's carbon intensity is reduced by at least 70% and the total annual GHG emissions by at least 50% relative to 2008;
- as soon as possible after 2050 the fleet is fully decarbonized.

Given these targets, this study will focus on cost and availability scenarios for 2030 and 2050.

Alternative bunker fuels

The scope of the availability analysis is limited to LBM and LSM. The availability of other low-/zero-carbon bunker fuels, such as hydrogen, synthetic ammonia, methanol or biodiesel is not analysed.

Geographic scope

The study assesses the availability of LBM and LSM on a global level and relate them to the global energy demand of the global fleet engaged in international shipping.

Assessment of availability

This study assesses the *maximum conceivable supply* of LBM. This means that when assessing the availability of LBM we assume that the available volume of a relevant biomass feedstock will entirely be used to produce LBM, at least if the production capacity allows for this. In other words, the study does not take competition for resources into account.

In addition, the study does not estimate the share of the maximum conceivable supply that might become available for the shipping sector. In Chapter 5 however, the availability for and the demand of LBM/LSM for the shipping sector is discussed.

Although the maximum conceivable supply implies an assessment of the technical potential only, this is not possible in practice. In reality, the technical and economic potential are strongly intertwined: especially the technical potential is determined by many economic factors. The business case of alternative fuels is heavily influenced by policy incentives and technological developments are also influenced by policy objectives and economic incentives, such as subsidies or obligations. In this report, we define the maximum conceivable supply as the supply that could be achieved assuming that investments in LBM and LSM are profitable, either through market factors or through regulatory intervention.

Shipping sector

The study focuses on the shipping sector, noting that other sectors may compete for biomethane, synthetic methane, biomass, renewable electricity and other inputs to the production of biomethane and synthetic methane.

Assessment of costs

To be able to assess the affordability of LBM and LSM for the shipping sector, production costs of LBM and LSM are estimated for 2030 up until the point of delivery to a ship. They are compared with bunker price estimates of fossil LNG and VLSFO, taking a carbon mark-up into account.

In addition, the estimated 2030 cost price at plant of LBM and LSM is compared with the cost price at plant of two alternative, renewable fuels (liquid hydrogen and ammonia). Transport and bunker infrastructure costs are not considered in this context.

When comparing the cost (price) of different bunker fuel types, the actual change of the ships' operational costs is not considered, i.e. the energy efficiency of the different according propulsion systems is not accounted for.

Conversion routes hydrogen and other synthetic fuels considered

Next to fossil bunker fuels and LBM, the cost analysis considers hydrogen, LSM, and ammonia. For the hydrogen as such and for the hydrogen that is required as an input for the production of LSM and ammonia, the study considers so-called green hydrogen. Green hydrogen is produced by means of water electrolysis.

Blue hydrogen is not considered in this study. If blue hydrogen, which is produced from natural gas, would be used instead of green hydrogen, the CO_2 stemming from the combustion of the blue hydrogen and the synthetic fuels based on blue hydrogen would have to be captured and stored for the fuels to be considered low/zero fossil carbon fuels. CO_2 storage capacity will be scarce in the long run and could therefore restrict the volume of blue hydrogen/fuels based on blue hydrogen to be used. In addition, blue hydrogen in combination with CCS is, at least in the long run, expected to be more expensive than green hydrogen.[5]

[5] See for example (Lloyd's Register; UMAS, 2019) and (CE Delft, 2018b).

GHG reduction potential

In the value chain of marine fuels two main phases can be distinguished: well-to-hull and hull-to-wake.

In the well-to-hull phase of fossil marine LNG, natural gas is extracted, processed, transported to and stored at a main LNG terminal and is subsequently distributed to ports for bunkering. In this first phase, GHG emissions result from the combustion of different fossil fuels and from uncombusted natural gas which can slip at different points in the value chain as well as due to flaring and venting practices during natural gas production. Flaring[6] and venting are applied if the gas quality is not sufficient or if there is not sufficient pipeline capacity. In the hull-to-wake phase, LNG is used on board ships, with GHG emissions resulting from the combustion of LNG and from the slip of uncombusted methane. The amount of methane slip thereby depends on the engine type and the operation of the engines.

If LBM or LSM is used instead of LNG, the hull-to-wake carbon emissions should be accounted for as zero emissions (see Annex A for an overview of how the GHG emissions of biofuels are accounted for under IPCC and EU rules), whereas the other hull-to-wake GHG emissions can be expected to be the same as for fossil LNG and should be accounted for in the same way.

The well-to-hull emissions of LBM and LSM can expected to change compared to fossil LNG, due to structurally different supply chains.

The actual GHG reduction potential of LBM and LSM and the other alternative fuels are out of the scope of the study.

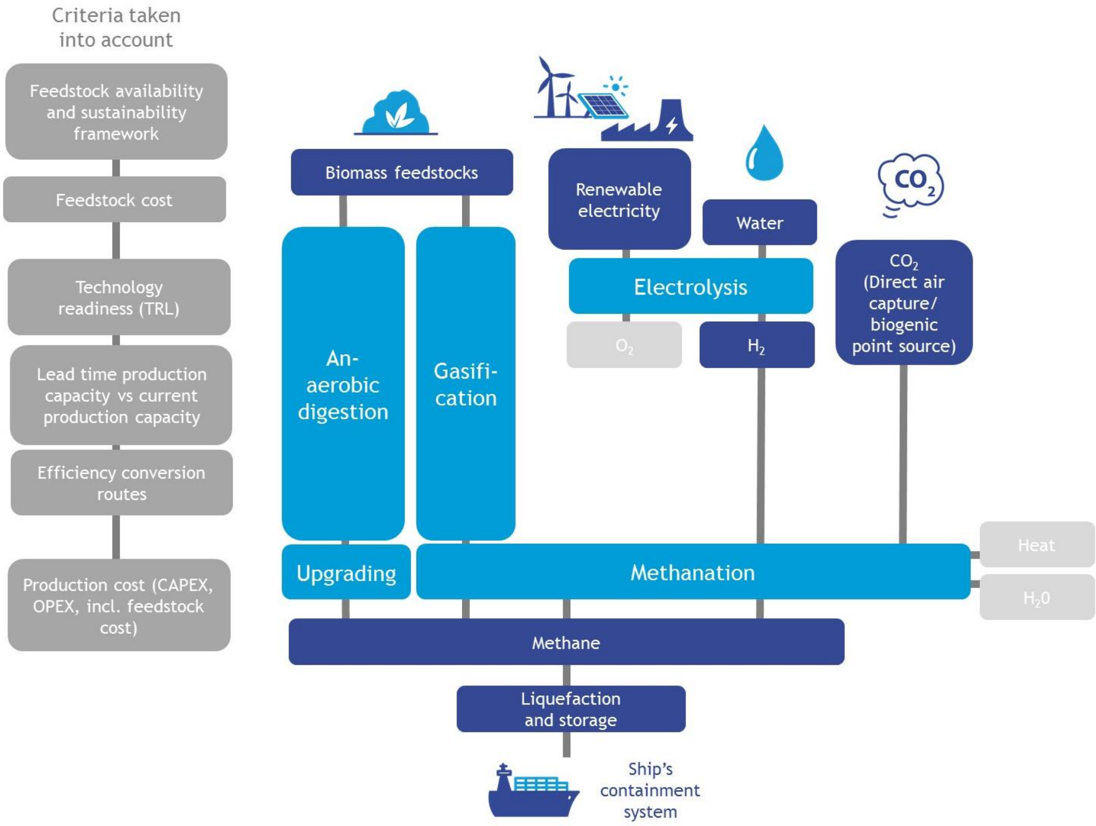
1.4 Approach

Figure 3 shows a schematic overview of the supply chain of LBM and LSM, with on the left a list of criteria applied to estimate the maximum conceivable supply. For both fuel types, we thereby start off with a scoping analysis in which the different possible production processes and inputs are described and relevant combinations of production process and inputs are elaborated. The next step includes an assessment of feedstock availability and feedstock cost. In the following step, the conversion technologies are assessed using criteria, such as technology readiness level (TRL)[7], etc. Lead times to increase production capacity are especially relevant in relation to 2030.

6 Flaring leads to methane emissions if not properly operated.

7 Technology readiness levels indicate how close to commercialisation technologies are. 9 levels are differentiated: Level 1 indicates the lowest and Level 2 the highest readiness.

Figure 3 — Schematic overview of supply chain of LBM and LSM



1.5 Structure of report

The study is structured as follows:
- Chapters 2 and 3 analyse the availability and the cost price of LBM and LSM respectively.
- Chapter 4 compares the expected cost price of LBM and LSM with the expected (cost) price of other marine bunker fuels.
- Chapter 5 discusses the availability of and demand for LBM and LSM by the maritime shipping sector.
- Chapter 6 gives recommendations to industry and policy makers as to how to address practical barriers to the scaling of LBM and LSM as marine fuel.
- Chapter 7 presents the main conclusions from the study.

2 Availability and cost price of liquefied biomethane (LBM)

In this section we estimate the maximum global availability (Section 2.2) and cost price (Section 2.3) of methane that is produced from biomass feedstocks in the current situation, as well as in 2030 and 2050. In order to determine the global availability of LBM, we first identify the main conversion routes and biomass feedstocks (Section 2.1). The analyses have been carried out by means of a literature review.

2.1 Scoping analysis

In the scoping analysis we identify and describe the main conversion routes and biomass feedstocks for the production of biomethane and present relevant technology-feedstock combinations.

2.1.1 Main conversion routes

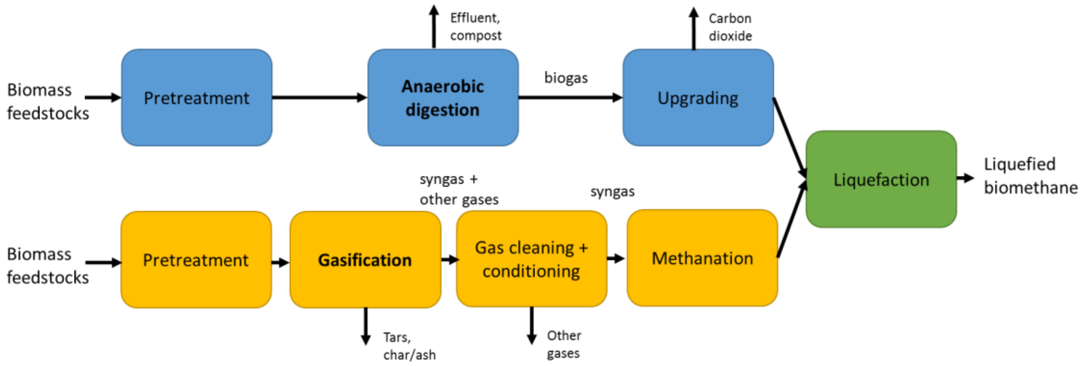
As depicted in Figure 4, there are two main types of conversion routes for the production of biomethane from biomass: anaerobic digestion and gasification.

Anaerobic digestion is a collection of processes in which microorganisms break down biomass feedstocks in the absence of oxygen. The feedstocks sometimes undergo a pre-treatment step such increasing the moisture content to the required level.
The anaerobic digestion processes result in biogas, which is a mixture of methane, carbon dioxide (30-50%), and other gasses such as hydrogen sulphide. In an upgrading step, the carbon dioxide is separated from the (bio)methane.

Gasification is a process in which biomass feedstocks react at high temperatures (> 700°C) with a certain amount of oxygen and/or steam and are converted into syngas (short for synthesis gas), which is a gas mixture that consists mainly of hydrogen and carbon monoxide. In a preceding pre-treatment step biomass is dried and reformed by means of pyrolysis (Sikarwar, et al., 2016). After gasification, gas cleaning and conditioning, the syngas is fed into a methanation process.

Independent of the conversion route, biomethane has to be liquefied to obtain LBM.

Figure 4 – The two main conversion routes for the production of LBM



Various detailed technology options fall under these two main conversion routes. These deal particularly with the core system (the AD system or the gasifier) and are listed below. Note that not all of the technologies are technologically mature at present, but as shown further down in the report, all of the following technologies can be expected to become technologically mature in the coming decades.

For the anaerobic digestion conversion route, technology options are:
- *Single-stage:* "all wastes are loaded simultaneously, and all AD processes are allowed to occur in the same reactor" (Meegoda, et al., 2018).
- *Multi-stage:* digestion steps in different reactors.
- *Mono-, co-, and all-feedstock digesters:* Digestion units can be designed and optimized for a specific single feedstock types or for multiple feedstocks. However, the used process technology is essentially the same. The different types of digesters are further considered below, as used feedstock types and unit sizes do differ. Manure digestion is a common type of mono-digestion (CE Delft, 2018c).
- *Autogenerative High Pressure Digestion (AHPD):* This is an innovative technology developed and patented by the Dutch company Bareau. It produces relatively pure biomethane without biogas as an intermediate product. Thus, the upgrading step is not part of the conversion route of this technology (CE Delft, 2018c).
- *Thermal Pressure Hydrolysis (TPH):* Feedstocks are, together with process water, heated to 150-160°C and pressurized, resulting in partial hydrolysis of the biomass. By means of instantaneous pressure release the water evaporates in such a way that the molecule structure of the biomass is cracked (CE Delft, 2018c).

For gasification, the technology options are:
- Wood gasification:
  - *Fixed bed:* Has a simple configuration and is flexible in use of feedstocks. Capacity of 1-10 MW_{th}. (WBA, 2015);
  - *Fluidized bed:* Capacity of 10-200 MW_{th} (WBA, 2015);
  - *Entrained flow:* High conversion efficiency but requires feedstock fractions smaller than 1 mm. Unit capacities from 2 MW_{th} to more than 100 MW_{th} (WBA, 2015).
- *Plasma gasification:* Emerging technology. "Usage of plasma as a heat source during gasification or as a tar-cracking agent downstream". Has high investment cost, is electricity intensive and has a low efficiency (Sikarwar, et al., 2016).
- *Supercritical water gasification:* Emerging technology. Form of hydrothermal gasification. Gasification carried out in supercritical water. Liquid biomass and solid biomass with a high moisture content can be processed with this (Singh Sikarwar et al., 2016). Solid biomass can be used as well, but needs to be broken down in small particles

and mixed with water to create a pumpable slurry in the pre-treatment step (Pinkard, et al., 2019).

2.1.2 Biomass feedstocks

Essentially, all types of biomass feedstock could be used for the production of biomethane. A classification of biomass feedstocks, differentiating between the type of stream and the sector the stream stems from, are given in Table 3. Also, some examples of specific feedstock types are provided.

Table 3 — Classification of biomass feedstocks

Sector	Type of stream	Examples of specific feedstock types
Agriculture	Production	Maize, sugarcane, sugar beet, soy, rapeseed
	Primary residues	Beet leaves, straw, solid manure, slurry (wet manure)
	Secondary residues	Beet pulp, slaughterhouse waste, shells
	Tertiary residues	Organic fraction of municipal solid waste, other organic waste, sewage sludge, disposed textile, used fats and oils, landfill gas
Forestry	Production	Roundwood
	Primary residues	Branches, leaves, bark, roots
	Secondary residues	Sawdust, black liquor
	Tertiary residues	Waste wood, disposed paper and cardboard
Aquaculture	Production	Algae, sea weed
	Secondary residues	By-products from biodiesel production from aquatic biomass, waste from fish-farming
Other	Production	Lignocellulosic energy crops (willow, poplar, miscanthus, switch grass)
	Primary residues	Roadside grass, biomass from maintenance of reed beds and watercourses, landscape care wood

In studies on global biomass potential, a distinction is often used between the following four biomass categories:
1. Energy crops (grown solely for energy purposes).
2. Agricultural residues.
3. Forestry products and residues.
4. Aquatic biomass.

For this reason, we will adopt these four biomass categories in the availability analysis presented in Section 2.2.

Based on sustainability assessments and frameworks foreseen for the future, such as the EU Renewable Energy Directive (RED II), not all four categories of biomass are preferred to be used to the same extent as renewable energy source. For energy crops for example, the RED II caps the contribution from food and feed crops, which means that the use of these feedstocks is limited due to sustainability concerns, especially in relation to indirect land use change (ILUC). For biomethane from anaerobic digestion based on maize is therefore less desirable from an RED II-perspective, because maize falls within the category of food and feed crops. There is, however, an option to use food and feed crops in case their low-ILUC risk can be proven by means of certification as laid down in the delegated act from March 2019. Due to this possibility, it is hard to simply exclude this category of energy crops in this analysis, but we will present energy crops as a separate category in the results.

The use of used cooking oil and animal fats is capped under the RED II too. Their availability is limited. This implies that the increase in renewable energy required to meet the EU renewable energy target for transport has to come from advanced biofuels stemming from other residues. Biofuels from aquatic biomass produced in installations on land are classified as advanced biofuels, but biofuels produced from macroalgae (seaweed) cultivated at sea are not, because the magnitude of the associated environmental risks are still uncertain (see Section 2.2.3). Other options, including manure, organic waste and agricultural residues will be classified as advanced biofuels and are favoured under the RED II-framework. In addition, developments and growth in gasification will open up the options to also include more forestry residues, which are also listed as potential feedstocks for advanced biofuels.

Regarding the using of roundwood (biomass from forestry production), it must be noted that the sustainability of this type of biomass is subject to debate. The sustainability is to a large extent determined by how forests are being managed. However, many small forest owners in North America have not certified their wood resources. This does not necessarily mean that their wood resources are unsustainable but means the sustainability can at least not be proven. Another point of discussion is carbon debt. Carbon debt can be defined as the carbon balance of wood resources between reduced carbon stocks of a forest due to harvesting or land-use on the one hand, and carbon sequestration through forest (re)growth and carbon offsets of avoiding emissions from fossil fuels on the other (Hanssen, 2015).
In other words: carbon debt is about the difference between the pace of emitting CO_2 from wood combustion versus how fast a forest can recapture the CO_2 again. Stakeholders do have discussions on what payback time is required to restore the carbon balance in relation to the GHG emission reduction targets of various sectors.

2.1.3 Technology-feedstock combinations

Different biomass conversion technologies exist, each with their own set of suitable biomass feedstocks. Table 4 provides an overview of the different anaerobic digestion and gasification technologies, along with their suitable feedstock types, typical unit sizes and technology readiness levels.

Table 4 — Conversion routes, underlying technologies and corresponding characteristics (based on CE Delft, 2018c)

Conversion route	Technology	Feedstocks	Unit size	Technological readiness level
Anaerobic digestion	Manure digestion	Slurry (cow and pig), solid manure (cow)	Often small scale (20-50 m^3 biogas per hour)	Commercial
	Co-digestion	Manure, sludge, organic waste, maize, straw, roadside grass	Small to middle-large scale (~500 m^3 biogas per hour)	Commercial
	All-feedstock digestion	Manure, sludge, organic waste, maize, straw, roadside grass	Large scale (800-10,000 m^3 biogas per hour)	Commercial
	Dry digestion	Organic waste, maize	Large scale (~1,500 m^3 biogas per hour)	Commercial
	Thermal Pressure Hydrolysis (TPH)	Sludge	Middle-large scale (~350 m^3 biogas per hour)	Commercial

Conversion route	Technology	Feedstocks	Unit size	Technological readiness level
	Autogenerative High Pressure Digestion (AHPD)	Sludge, manure (pig), agricultural residues	*Unknown*	TRL 8 (scale-up phase)
Gasification	Wood gasification	Woodchips (from forestry production and primary residue streams), bark, waste wood	From 10 MW to considerably larger volumes	Demonstration units on semi-commercial scale
	Supercritical water gasification	All types of biomass feedstocks	0.7-3.3 MW [a]	Pilot plant is under construction in the Netherlands

Sources: a: STOWA (2016); If no source is indicated, the source is CE Delft (2018c).

Table 4 shows that different dedicated anaerobic digestion systems have been developed for different biomass feedstock types. The unit sizes of digesters are often optimized based on the types of feedstocks used and the available feedstock volumes (CE Delft, 2018c). Gasification systems are generally not optimised for particular feedstocks, as the gasification process is not as dependent on feedstock composition as is the AD process.

Gasification systems typically use dry, woody (lignocellulosic) biomass, whereas anaerobic digestion systems use wet feedstock types. However, supercritical water gasifiers can process all types of feedstocks, both woody and non-woody. These gasifiers require wet feedstocks, which means that dry biomass must be mixed with water.

An important technical observation is that most anaerobic digestion technologies have entered the market, whereas gasification technologies still need to be demonstrated commercially.

2.2 Availability analysis

In this section we determine the maximum conceivable global supply of LBM in the current situation, in 2030 and 2050. This amount poses a physical limit on the amount of LBM that could possibly be used by marine shipping worldwide.

The maximum conceivable supply is calculated by taking into account three main factors:
— the global availability of relevant biomass feedstocks;
— the development of the global biomethane production capacity; and
— the LBM production yield of the conversion routes, assuming all biomethane will be converted to LBM.

We will discuss these factors separately before calculating the maximum conceivable supply of LBM.

2.2.1 Global availability of biomass feedstocks

Bioenergy provides around 9% of global primary energy demand, a high share of which is ‘traditional’ bioenergy in the form of charcoal from unsustainable deforestation, used in developing countries to produce heat for cooking. Other forms of bioenergy add up to 4% of global primary energy demand (CCC, 2018). Considering that the global primary energy supply was 571 EJ in 2015 (IEA, 2017b), the current contribution of biomass to energy consumption worldwide is about 50 EJ.

When studying the bioenergy potential, it is important to distinguish between different 'types' of potentials. Bioenergy potential studies often estimate a technical potential and/or a sustainable potential. The technical potential is the biomass that could become available for the production of bioenergy. The use of biomass for the production of food, feed and fibres is excluded from this. This means that crops for bioenergy are only grown on 'surplus land', i.e. land that is not used for production of food, feed and fibres. However, the technical potential does not take into account environmental constraints. Therefore, utilization of the technical potential could result in e.g. loss of biodiversity and land degradation. In the sustainable potential, such environmental constraints are taken into account, often resulting in biomass availability values that are well below the technical potential (PwC EU, 2017). The sustainability criteria applied might, however, vary per literary source and are often not explicitly mentioned.

In order to determine the maximum conceivable supply of LBM, we first estimate both the technical potential and the sustainable potential of global primary bioenergy production. We base our estimation on literature on bioenergy potential. Table 5 and Table 6 contain an overview of studies that estimate the global bioenergy potential for 2030 and 2050, respectively. Because aquatic biomass is not considered in these studies, we have studied this biomass category separately in Section 2.2.3.

Most of the literature estimating/reviewing studies that estimate the global bioenergy potential in 2030 (Table 5) assesses the *sustainable* potential. We can observe that the estimated ranges of the global bioenergy potential are similar for most of the part. The minimum value given by Daioglou et al. (2019) is however relatively low, but this is based on climate mitigation scenarios, where bioenergy use may be lower than the sustainable potential. IRENA (2014) include in their literature review not only the sustainable but also the technical potential figures, resulting in a maximum value of 350 EJ, which is 2-3 times higher than the sustainable potential estimates in other studies.

Table 5 — Literature overview of global bioenergy potential in 2030

Biomass category	Minimum value (EJ)	Maximum value (EJ)	Type of potential	Source	Remarks
Energy crops	25	90	Technical + sustainable	IRENA (2014)	Based on literature review, including both technical and sustainable potential studies.
Agricultural residues	25	190			
Forestry production and residues	70	70			
Total	**120**	**350**			
Total bioenergy potential in IPCC (2011)	**100**	**130**	Sustainable	IPCC (2011)	
Energy crops	33	39	Sustainable	IRENA (2014)	Estimations by IRENA.
Agricultural residues	37	66			
Forestry production and residues	27	43			
Total	**97**	**147**			
Woody biomass	10	48	Sustainable	Daioglou et al. (2019)	Results from a climate mitigation study, in which the sustainable bioenergy production in different climate scenarios is assessed. As the purpose of this study was not to determine the bioenergy
Maize + sugarcane	5	10			
Grassy biomass	5	24			
Residues	10	50			
Total	**30**	**132**			

Biomass category	Minimum value (EJ)	Maximum value (EJ)	Type of potential	Source	Remarks
					potential, the given values can be considered to represent a minimum potential.

Note: Aquatic biomass has not been estimated in the studied bioenergy potential literature, and is therefore not included here. We will treat this biomass category separately.

Our literature study of global bioenergy potential in 2050 (Table 6) contains multiple estimates of both technical potential and sustainable potential. The technical potential studies report a similar minimum value of ~100 EJ, but the maximum value varies from 600 EJ in IPCC (2011) to 1,723 EJ in Slade et al. (2014). These large variations are caused by different assumptions on, and estimations of, uncertain technological, economic and social developments. The studies use different scenarios and assumptions on, among others, population growth, global food demand, growth in productivity of agriculture and livestock, and the use of degraded and marginal lands for energy crop production.

Table 6 — Literature overview of global bioenergy potential in 2050

Biomass category	Minimum value (EJ)	Maximum value (EJ)	Type of potential	Source	Remarks
Energy crop production on surplus land	-	120	Technical	IPCC (2011)	'Surplus' land concerns land that is not used for the production of food, feed and fibres. The 'improvements' are in agricultural and livestock management. The minimum values for the energy crop categories were not given by IPCC (2011).
Energy crops on marginal and degraded lands	-	70			
Energy crops due to improvements	-	140			
Residues from forestry, agriculture and organic wastes	40	170			
Surplus forestry products	60	100			
Total	**100**	**600**			
Energy crops	22	1,272	Technical	Slade et al. (2014)	Based on literature study by authors. They note that estimates above 600 EJ in total are 'extreme'.
Agricultural residues	10	66			
Forestry residues	3	35			
Wastes	12	120			
Forestry	60	230			
Total	**107**	**1,723**			
Traditional biomass	10	20	Technical	Creutzig et al. (2015)	
Forest and agricultural residues	40	125			
Dedicated crops	25	675			
Optimal forest harvesting	25	75			
Total	**100**	**895**			
Bioenergy crops	0	130		IRENA (2014)	Based on literature review by authors. The review include both
Agricultural residues	0	560			

Biomass category	Minimum value (EJ)	Maximum value (EJ)	Type of potential	Source	Remarks
Forestry products	0	220	Technical + Sustainable		studies estimating a technical potential and studies estimating a sustainable potential.
Total	**0**	**910**			
Total bioenergy potential in IPCC (2011)	**100**	**184**	Sustainable	IPCC (2011)	The source does not give a minimum value. This value has been set equal to the minimum value given by IPCC (2011) for 2030.
Energy crops	40	110	Sustainable	Searle and Malins (2015)	Based on a reassessment of figures collected through literature study, resulting in “the maximum sustainable bioenergy potential that could realistically be achieved”.
Forestry, residues and wastes	10	20			
Total	**50**	**130**			
Woody biomass	0	40	Sustainable	Daioglou et al. (2019)	Results from climate mitigation scenarios. These numbers may be lower than the sustainable potential of biomass for energy purposes.
Maize + sugarcane	0	10			
Grassy biomass	25	65			
Residues	45	70			
Total	**70**	**185**			

Note: Aquatic biomass has not been estimated in the studied bioenergy potential literature, and is therefore not included here. We will treat this biomass category separately.

2.2.2 Availability in different world regions

The globally available amount of biomass feedstocks is not equally distributed over world regions. To gain some insight in the distribution of biomass for energy over the world, we present in this paragraph bioenergy potential estimations for different world regions.

We have found six studies in which bioenergy potential estimations have been made for different world regions. These studies only analyse main biomass categories (agricultural and forestry production and residues), they do not go into detail on specific biomass feedstocks such as maize and manure. However, it is difficult to compare the studies, because they differ in terms of included years, region boundaries, considered biomass feedstock types, and the type of potential (technical or sustainable). A main barrier for comparison is the fact that the included countries per region vary between studies. For this reason, we present here the regional bioenergy potentials of two studies, Daioglou et al. (2019) and IRENA (2014). Both studies provide estimates of the sustainable potential of agricultural and forestry feedstocks in 2030.

Daioglou et al. (2019) give sustainable production figures for energy crops and agricultural and forestry residues in 2030 for different socio-economic climate scenarios. Because this study is an analysis of the actual use of biomass, the outcomes are technically not estimations of the bioenergy potential. However, they can be considered to represent a minimum value of the sustainable bioenergy potential. In addition, Daioglou et al. (2019) take into account the demand for biomass for other purposes than energy (for example as a feedstock for the chemical industry) in their estimation of bioenergy potential, which further lowers the provided bioenergy estimations.

Table 7 gives the estimations in EJ/year from Daioglou et al. (2019) for the scenario with the highest global biomass production, as this best approaches the bioenergy potential.

These are values from a climate scenario in which the challenges of climate adaptation and climate mitigation are relatively small, due to a low-meat diet and continuous improvements of agriculture and animal husbandry.

Table 7 — Sustainable potential of biomass in world regions in 2030 (in EJ/year), based on Daioglou et al. (2019)

	Agricultural production	Agricultural and forestry residues	Total per region	Share of region
Asia	3.7	19.8	**23.5**	33%
Latin America	7.5	2.6	**10.1**	14%
Africa and Middle East	5.4	5.7	**11.2**	16%
OECD regions	2.2	16.3	**18.5**	26%
Former Soviet Union states	0.9	6.5	**7.4**	10%
Total (world)	**19.7**	**50.9**	**70.6**	**100%**

IRENA (2014) has analysed the sustainable biomass potential in 2030 by means of two scenarios, which lead to two different estimates per biomass type per world region. In the 'high range of supply scenario' marginally suitable land types are utilised to produce energy crops, unlike in the 'low range of supply scenario'. Besides, a larger part of the secondary agricultural residues are recoverable for bioenergy production in the 'high range of supply scenario' (25-90%, compared to 25% in the 'lower range of supply scenario'). The biomass potential estimates from IRENA (2014) are shown in Table 8. The different scenario values are indicated with ranges.

Table 8 — Sustainable potential of biomass in world regions in 2030 in EJ/year

	Agricultural production	Agricultural residues	Forestry production	Forestry residues	Total per region	Share of region
Asia	0.4-0.6	15.9-32.1	1.6-2.2	3.8-4.3	**21.7-39.2**	22-27%
Latin America	14.2-16.2	5.0-9.4	0.0-0.3	1.5-1.5	**20.7-27.4**	19-21%
Africa	4.5-5.2	3.5-5.7	0.0-0.0	0.8-1.1	**8.8-12.1**	8-9%
Europe	5.7-7.1	5.8-8.3	0.3-13.1	6.6-7.7	**18.5-36.2**	19-25%
North America	6.6-7.5	5.8-8.8	3.3-3.4	7.7-7.7	**23.4-27.4**	19-24%
OECD Pacific	1.7-1.9	0.8-1.3	0.1-0.2	1.0-1.3	**3.7-4.7**	3-4%
Total (world)	**33.1-38.6**	**36.9-65.7**	**5.3-19.0**	**21.4-23.6**	**96.7-146.9**	**100%**

Source: (IRENA, 2014).

We can observe that IRENA (2014) arrives at a range of 97-147 EJ/year in 2030. This is higher than the 71 EJ estimated by Daioglou et al. (2019), but given that the latter did not include forestry production (trees grown for bioenergy) and included economic restrictions, these total values are in proportion.

The shares of the sustainable bioenergy potential for different world regions given by Daioglou et al. (2019) and IRENA (2014) are illustrated in Figure 5 and Figure 6 respectively. Because the two studies apply different regional boundaries, a comparison per region is difficult to make. Both studies display a spread of the globally available sustainable biomass over Asia, Latin America, Africa, and North America and Europe (OECD regions).
Regional biomass shares that stand out in IRENA (2014) are a share of more than 40% of globally available energy crops in Latin America, a share of more than 40% of agricultural residues in Asia, and a share of about 60% forestry production in North America.

These shares cannot be observed in Daioglou et al. (2019), but this is partly caused by different regional boundaries and different sets of biomass categories.

General observations are that in both studies about a quarter to a third of the global potential is located in Asia and that OECD regions contribute 25 to 55% to the total potential. However, the distribution over regions varies between different types of biomass.

Figure 5 — Distribution of sustainable bioenergy potential over world regions in 2030, based on Daioglou et al. (2019)

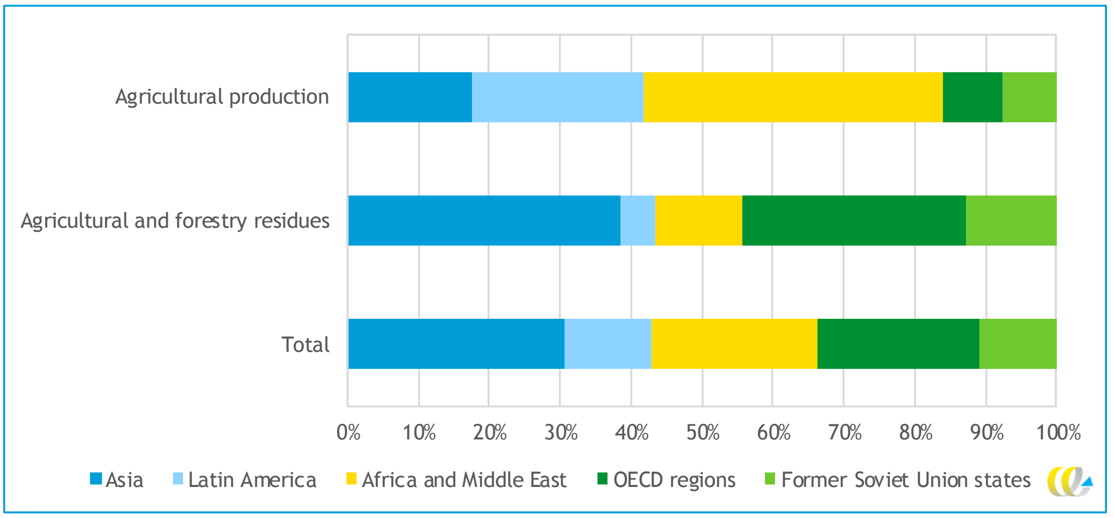
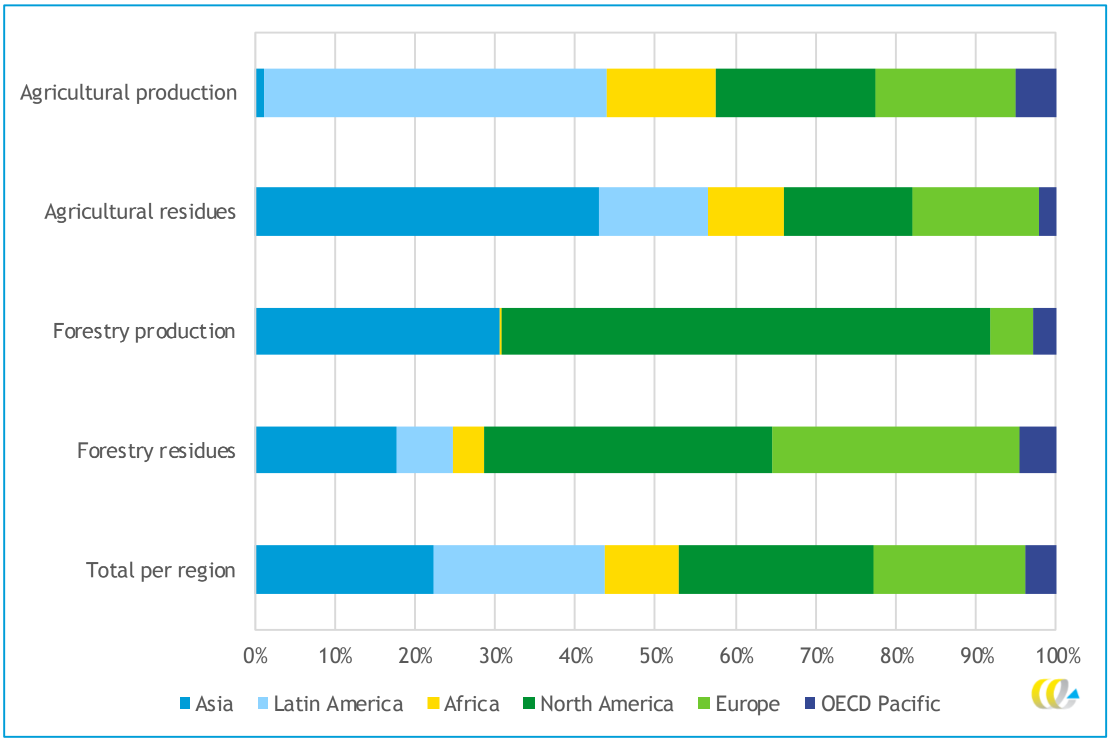


Figure 6 — Distribution of sustainable bioenergy potential over world regions in 2030, based on the values of the 'low range of supply' scenario from IRENA (2014)



2.2.3 Availability of aquatic biomass

The theoretical production potential of aquatic biomass is enormous, taking into account that this biomass can be grown in seas and oceans. However, the production and processing technologies required are in an early stage of development, and there are still many uncertainties on suitable ocean areas and technological, economic and ecological constraints. As a result, researchers have only indicated a theoretical potential of aquatic biomass for the production of bioenergy so far. Because this potential overshadows the potential of the other biomass categories, we dive deeper into the potential of aquatic biomass in this subparagraph.

Introduction

Aquatic biomass centers around algae. A main distinction exists between macroalgae (also called seaweed) and microalgae. Microalgae are unicellular microscopic algae, which are cultivated in open ponds or bioreactors on land. Macroalgae are larger aquatic organisms, and can be cultivated in the sea, using for example lines and nets for the algae to grow on. The bioenergy yield per unit of mass from macroalgae is generally lower than from microalgae, but the production costs are much lower (Dibenedetto, 2011).
The production of microalgae, when cultivated in bioreactors, compete with the growth of food crops and other functions for scarce land areas. We focus here on macroalgae, because a huge surface area is theoretically available (the oceans' surface area).

Advantages and disadvantages

Aquatic biomass cultivation has distinct advantages. First, it does not interfere with agricultural land, while having a similar or higher energy content and a higher growth rate compared to terrestrial plants. Macroalgae contain little lignin, which make them suitable for the production of biomethane (Ghadiryanfar, et al., 2016). Furthermore, cultivation of aquatic biomass can be part of a coastal defence system against floods and offer socio-economic opportunities to coastal communities.

There are however also disadvantages related to aquatic biomass cultivation. First, very large areas with massive cultivation are needed to make a meaningful contribution to energy supply. Furthermore, areas are restricted to coastal or nutrient rich waters, unless artificial fertilizers are used, or pump systems that bring nutrients from the deep water to the surface (which is energy-intensive). Favourable seaweed production depends also on temperature, light and salt content, as well as water movement. Second, there are multiple financial and technical constraints which make large scale cultivation currently unviable. Thirdly, there are several ecological risks associated with large-scale cultivation: ecosystems and migratory patterns of marine species might be negatively affected. Also, algae could extract too many nutrients, which are essential for other species. Harvesting delays, on the other hand, might cause eutrophication (an oversupply of nutrients).

Literature overview of the global potential

A lot of research has been carried out on the use of algae for the production of biofuels and as a means for CO_2 sequestration. However, studies that provide an estimate of the global primary energy potential of aquatic biomass are scarce. This is probably due to the knowledge gaps that still exist about the production yield of macroalgae, the suitability of different ocean regions, the technical feasibility of production (e.g., sufficient availability of nutrients) and the impacts on ecosystems. We have found two sources that assess the global macroalgae potential. We have used a suitable global ocean area estimate given by a third study to make another estimation of the macroalgae production potential in 2050. The estimations are shown in Table 9.

Ecofys (2008) investigated the potential of different options for the production of aquatic biomass for energy applications worldwide. If the algae are grown on horizontal lines between offshore infrastructure, a potential area of 550 million hectares is available worldwide, which would lead to 110 EJ. If only densely used coastal areas (up to 25 km) are used, an area of around 370 million hectare, a production of 35 EJ could be reached. In case macroalgae are cultivated in the biological deserts of the open oceans, an area of over 5 billion hectares becomes available. Utilising this area, a production amount of 6,000 EJ/year could theoretically be achieved.

The study by Lehahn et al. (2016) appears to be based on a detailed analysis of the macroalgae production potential. This analysis gives a theoretical potential of macroalgae production at sea, concerning 'the next 50 years'. The modelling results show that in theory (without technological or ecological restrictions) macroalgae can be cultivated in approximately 10% of the World Ocean. If algae are only produced in areas with a water depth less than 100 meters and closer than 400 kilometres to the shore, the potential is much smaller (18 EJ, instead of 2,052 EJ). The required technology is not available yet, which is why the authors speak of a theoretical potential.

Froehlich et al. (2019) discuss the potential of macroalgae to capture and store CO_2 and thereby contribute to climate change mitigation. In this context, they have mapped out the nutrient levels and ocean temperatures in ocean water within national jurisdictions (Exclusive Economic Zones)[8], using oceanographic, biological and production data. With this, they have determined that about 48 million km^2 are 'ecologically available' for the production of macroalgae, taking into account the nutrient and temperature requirements of a large set of macroalgae species. A algae production potential is not mentioned, but applying a macroalgae production yield of 2,000 ton/km^2 (Hughes, et al., 2012) and an energy content of 19.0 MJ per kilogram dry matter (Lehahn, et al., 2016), 1,824 EJ can be grown on this area.

[8] The ocean areas within national jurisdictions are the areas that are near the coastlines. They make up 36% of the total surface of the oceans.

Table 9 — Literature overview of estimates of the global macroalgae potential in 2050

Source	Potential (EJ/year)	Remarks
Ecofys (2008)	35	Cultivation in densely used coastal areas (up to 25 km from the coast).
	110	Cultivation using horizontal lines between offshore infrastructures.
	6,000	Macroalgae are cultivated in the biological deserts of the open oceans.
Lehahn et al. (2016)	18	Production in areas with a water depth less than 100 meters and closer than 400 kilometres to the shore.
	2,052	Production on 10% of the World Ocean.
Froehlich et al. (2019)	1,824	Calculated potential, using the finding that 48 million km^2 of ocean area is suitable for macroalgae production.

Global potential of aquatic biomass

The literature overview of the global potential of macroalgae production (Table 9) shows that the biggest determining factor of the potential is the size of the suitable ocean surface area. A main question here is: are only coastal ocean areas suitable, or can open ocean areas be used as well? Open oceans appear problematic locations for macroalgae production: the nutrient levels are lower, production facilities are more costly to install and the algae are more expensive to harvest. This is why we consider 6,000 EJ to be unattainable. Lehahn et al. (2016) provides an estimate of roughly 2,000 EJ, using 10% of the World Ocean (equal to about 36 million km^2), which is in the same order of magnitude as the ocean area considered suitable by Froehlich et al. (2019).

An estimation of the technical potential of aquatic biomass hinges on the question to what degree the potential of 2,000 EJ is technically possible. Offshore macroalgal production and harvesting systems are still under development (JRC, 2015). It is uncertain if the high production yield of more than 2,000 ton per km^2, which is required to realise 2,000 EJ on about 40 million km^2 of ocean area, can be realized in all ocean regions. In some regions, ecological conditions for macroalgal growth could be suboptimal, or macroalgae farming could be restricted by negative impacts on ecosystems or by naval transportation routes. Therefore, we set the global technical potential of aquatic biomass for this study to 1,000-2,000 EJ in 2050. Assuming that algae production will in some ocean regions damage ecosystems, we set the sustainable potential at 750-1,500 EJ.[9]

2.2.4 Global bioenergy potential

We have distilled from the literature study presented above a set of global bioenergy potential ranges for the years 2030 and 2050, for the four biomass categories, differentiating between sustainable and technical potential (see Table 6 and Figure 3, which both present the same data).

[9] There is not yet a clear sustainability framework for aquatic biomass. The RED II deals specifically with algae from cultivation in installations on land. Other types of aquatic biomass are not referred to.

Our main approach for setting a range was to select, for each of the four categories, the lowest value and the highest value from the various studies. When the estimates from the studied literature for the year 2050 were below those of 2030, we have used the 2030 values. These differences may be caused by the different methodologies, as we have looked at different studies for the year 2050 compared to the year 2030.

Regarding a maximum technical potential for energy crops in 2050, we have not used the 1,272 EJ value form Slade et al. (2014) as these authors call bioenergy potentials above 600 EJ 'extreme'. This 600 EJ is exactly equal to the maximum technical potential in 2050 given by IPCC (2011).Therefore, we have adopted the technical energy crop potential estimate from IPCC (2011).

A global aquatic biomass potential for the year 2030 has not been found in literature. Many researchers state that aquatic biomass production will not yet be profitable in 2030. Although the estimation of the economic biomass potential is out of the scope of this analysis, we take this important observation — which has such a large influence on the supply of aquatic biomass — into account. Therefore, we estimate the aquatic biomass potential in 2030 well below the values that would be obtained when interpolating the 2050 estimations.

Table 10 — Estimation of global primary bioenergy potentials for 2030 and 2050 (EJ)

Biomass category	Technical potential in 2030	Sustainable potential in 2030	Technical potential in 2050	Sustainable potential in 2050
Energy crops	25-90	25-40	25-330	25-110
Agricultural residues	25-190	10-65	25-560	10-65
Forestry products and residues	30-70	25-40	45-265	25-40
Aquatic biomass	50-100	50-100	1,000-2,000	750-1,500
Total (with aquatic biomass)	**130-450**	**110-245**	**1,095-3,155**	**810-1,715**
Total (without aquatic biomass)	**80-350**	**60-145**	**95-1,155**	**60-215**

Figure 7 — Estimation of global primary bioenergy potentials for 2030 and 2050 (EJ)

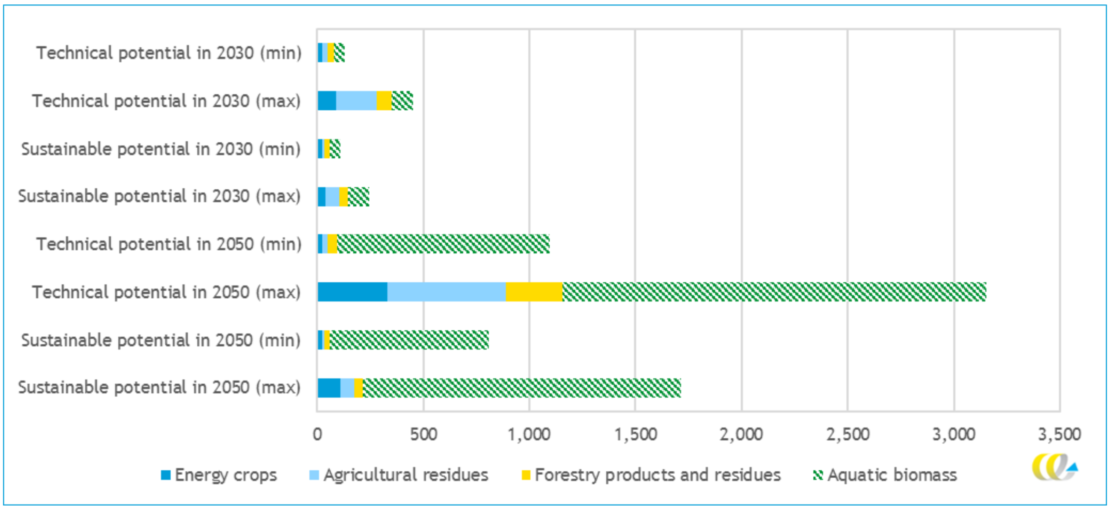


Figure 7 illustrates that the worldwide maximum sustainable bioenergy potential could become higher than 2,000 EJ in 2050 if aquatic biomass is accounted for. To put this into perspective: The global primary energy supply in 2015 was 571 EJ, and the current contribution of biomass to bioenergy consumption worldwide is about 50 EJ. Thus, the global bioenergy production in 2050 could become more than 40 times than today, if the potential is utilised.

Secondly, the global bioenergy potential might increase dramatically between 2030 and 2050. The potential in 2050 could be more than eight times higher in 2050 than in 2030, according to our assessment.

A third observation is that the estimated sustainable bioenergy potential is about half of the technical potential. When aquatic biomass is disregarded, the sustainable bioenergy potential is approximately 40% of the technical potential in 2030 and 20% in in 2050.

Fourth, aquatic biomass could play a major role in 2050, and bring back the relative contribution of land-based biomass (energy crops, agricultural residues and forestry products and residues) from 55-80% in 2030 to 5-35% in 2050. When only considering the sustainable potential, the share of land-based biomass would be approximately 60% in 2030 and 15% in 2050.

2.2.5 Production capacity

The global bioenergy production potential estimated for 2030 and 2050 in the last subsection, can only be realised if there is sufficient production capacity. For LBM production this includes production capacity for anaerobic digestion and biogas upgrading (for the anaerobic digestion route), gasification and methanation (for the gasification route) and liquefaction. According to Cedigaz (2019), biomethane production has risen exponentially since 2010, up to 3 billion m^3 in 2017 (Cedigaz, 2019).This is equal to a total energy value (based on the HHV of biomethane) of 0.12 EJ. According to Tybirk (2018), the current annual production capacity of LBM is 0.044 Mt, corresponding to 56 million m^3 of biomethane (or 0.002 EJ). Noticing that the minimum global bioenergy production potential in 2030 is 110 EJ (see Table 10), the current production capacity is only a fraction of the capacity needed to utilize the bioenergy production potential.

All of these systems could be built well within ten years. Whether these systems will actually be built primarily depends on their profitability. In turn, the profitability depends on the cost price of LBM and the selling price to ship operators and other customers in 2030 and 2050. Additionally, the relative profitability compared to other energy investments is a relevant factor. The LBM cost price will be discussed in Section 2.3. For the estimation of maximum conceivable supply we will assume that the required production capacity will be present, but with the remark that this will depend on the business case for investments in LBM production.

2.2.6 Production yield

In order to calculate the maximum conceivable LBM production from the potential available biomass for bioenergy, we need to know the production yield of different technology-feedstock combinations, in kilogram of biomethane per ton of dry matter. We present this information in Table 11.

Table 11 — Biomethane production yields for different technology-feedstock combinations

Conversion route	Technology	Feedstock	Biomethane production yield (kg biomethane / ton dry matter of feedstock)	Used source*
Anaerobic digestion	Manure digestion	Cattle slurry	86-216	NNFCC (2019)
		Pig slurry	108-270	
	Co-digestion	Manure + plant-based biomass	150-300**	Estimation by CE Delft
	All-feedstock digestion	Whole wheat crop	322-484	NNFCC (2019)
		Maize silage	348-575	
		Sugar beet	136-329	
		Straw	139-279	
		Sorted food waste	355-533	SGC (2012)
		Sludge	173-259	
		Seaweed	120-306	Milledge et al. (2019)
		Microalgae	94-450	
	Dry digestion	*Not found*	*Not found*	
	Thermal Pressure Hydrolysis (TPH)	*Not found*	*Not found*	
	Autogenerative High Pressure Digestion (AHPD)	*Not found*	*Not found*	
Gasification	Wood gasification	Wood	140-210	Göteborg Energi (2018)
		Woody biomass	135-140	CE Delft (2018c)
		Woody biomass	135-140	CE Delft (2018c)
		Woody biomass	135-140	CE Delft (2018c)
	Plasma gasification	*Not found*	*Not found*	
	Supercritical water gasification	Microalgae	288	CE Delft (2019)
		Sewage sludge	203	
		Chicken manure	225	

* Values have been calculated assuming a biomethane content in biogas of 50-75% (CE Delft, 2018c), no biomethane losses in the liquefaction process, and a calorific value of methane of 55.40 MJ/kg (HHV).

** Own estimation, based on the assumption that co-digesters use 50% manure and 50% plant-based biomass.

For various new technologies, information on suitable feedstocks and production yields has not been found in the literature. However, it is uncertain if these new technologies are ready for commercial application in 2030/2050 and whether they will be cost-competitive. We continue the analysis with existing technologies for which we have an estimation of the biomethane production yield, and for which we can find cost data for Section 2.3.

For the purpose of calculating the maximum conceivable supply of LBM, we adopt the conversion technology with the highest production yield for each of the four biomass categories used in this analysis (see Table 12).

Table 12 — Technologies and maximum biomethane production yields assumed in this study

Biomass feedstock categories	Technology	Maximum biomethane yield (kg/ton dry matter)
Energy crops	Anaerobic digestion	250-300
Agricultural residues	Anaerobic digestion	250-300
Forestry products and residues	Wood gasification	140-210
Aquatic biomass	Anaerobic digestion	250-300

We have derived a maximum production yield range for each of the four biomass categories from Table 11, considering the maximum yield values for different types of feedstock within each of the biomass feedstock categories.

Although wet biomass could also be processed by supercritical gasification, the production yields of anaerobic digestion appear higher. Moreover, anaerobic digestion is an operational technology, and therefore yields and cost levels are more certain.

2.2.7 Maximum conceivable supply of LBM

Finally, we can calculate the maximum conceivable supply of LBM worldwide in 2030 and 2050. To this end we have used the bioenergy potentials from Table 10, factors to convert the energy content of the biomass feedstocks into kilograms dry matter and the production yields from Table 12. The minimum value of the maximum conceivable supply has been calculated by taking the minimum biomethane production yield, and the maximum conceivable supply value by using the maximum production yield. The resulting maximum conceivable supply ranges of LBM are given in Table 13 (in Mt) and Table 14 (in EJ).
The same data are graphically presented in Figure 8 (Mt).

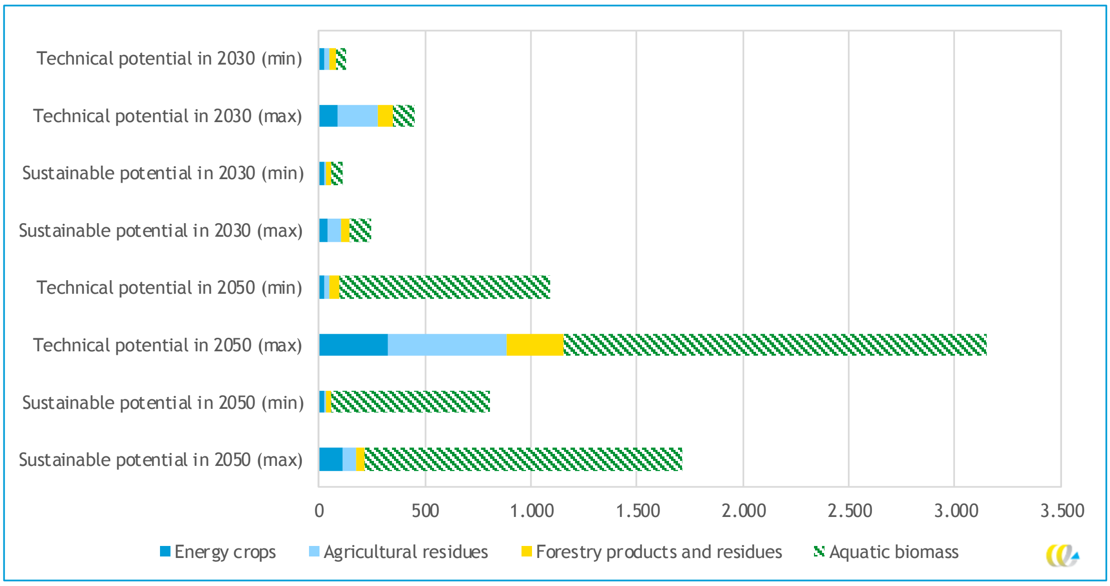
Table 13 — Global maximum conceivable supply of LBM in 2030 and 2050 (Mt)

Biomass category	Technical potential in 2030	Sustainable potential in 2030	Technical potential in 2050	Sustainable potential in 2050
Energy crops	350-1,500	350-650	350-5,450	350-1,800
Agricultural residues	350-3,150	150-1,100	350-9,300	150-1,100
Forestry products and residues	200-750	200-400	300-2,800	200-400
Aquatic biomass	650-1,600	650-1,600	13,150-31,600	9,850-23,700
Total (with aquatic biomass)	**1,600-7,000**	**1,300-3,700**	**14,200-49,100**	**10,500-27,000**
Total (without aquatic biomass)	900-5,400	650-2,200	1000-17,600	650-3,300

Table 14 — Global maximum conceivable supply of LBM in 2030 and 2050 (EJ)

Biomass category	Technical potential in 2030	Sustainable potential in 2030	Technical potential in 2050	Sustainable potential in 2050
Energy crops	19-83	19-37	19-303	19-101
Agricultural residues	19-174	8-60	19-514	8-60
Forestry products and residues	12-41	10-24	18-156	10-24
Aquatic biomass	36-87	36-87	729-1,749	547-1,312
Total (with aquatic biomass)	**86-386**	**73-207**	**785-2,722**	**583-1,496**
Total (without aquatic biomass)	50-298	37-120	56-973	37-184

Figure 8 — Global maximum conceivable supply of LBM in 2030 and 2050 (Mt)



Looking at the global maximum supply figures, we can make similar observations as for the global bioenergy potential figures. This is as expected, because we have applied the anaerobic digestion production yield range for three of the four biomass categories. The share of LBM from forestry products and residues is even smaller here, because the gasification technology applied to this biomass category has a lower production yield than that of anaerobic digestion. The main findings are:

- The global maximum sustainable LBM production could become higher than 40 Gt in 2050, although this heavily relies on the contribution of aquatic biomass. For comparison, 316 Mt of LNG have been traded globally in 2018 (IGU, 2019).
- The maximum conceivable supply could increase dramatically between 2030 and 2050. The maximum supply could be up to nine times higher in 2050 compared to 2030, according to our analysis based on literature review.
- The estimated maximum conceivable supply based on the sustainable bioenergy potential is substantially lower than the supply based on the technical potential: 20-45% lower (both years). When aquatic biomass is disregarded, the reductions are even higher: 60% lower in 2030 and 80% in 2050.
- Aquatic biomass could play a major role in 2050 and bring back the relative contribution of land-based biomass (energy crops, agricultural residues and forestry products and residues) to LBM production from 50-80% in 2030 to 5-35% in 2050. When only considering sustainable potential, the share of land-based biomass would be 50-60% in 2030 and 5-10% in 2050.

The energy consumption of the world maritime fleet has been estimated at 12.1-14.2 EJ in 2030 and 10.2-23.2 EJ in 2050 (Öko-Institut, CE Delft and DLR, ongoing). In 2050, ships will be more efficient than in 2030, but due to the increased demand for transport overall energy demand could still be higher in 2050.

The maximum conceivable sustainable supply of LBM in terms of energy is shown alongside the global maritime energy demand in Figure 9 (without aquatic biomass) and in Figure 10 (with aquatic biomass). A high and a low value is indicated for each of the demand and supply numbers.

Figure 9 — Maritime energy demand and global maximum sustainable supply of LBM in 2030 and 2050, without aquatic biomass (EJ)

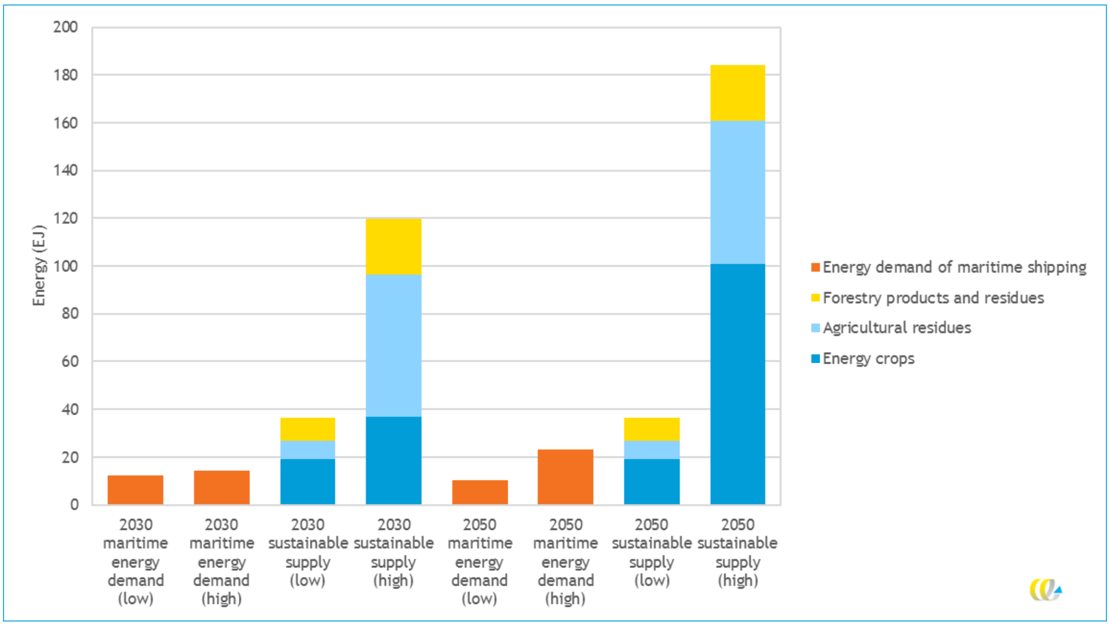
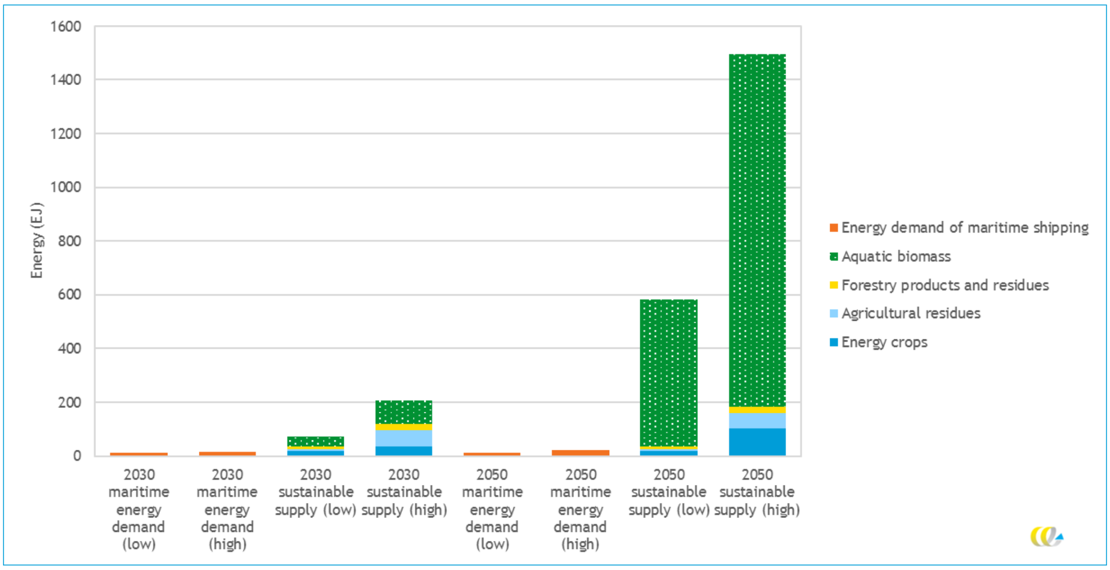


Figure 10 — Maritime energy demand and global maximum sustainable supply of LBM in 2030 and 2050, with aquatic biomass (EJ)



Comparing supply to demand, we can see that the maximum conceivable sustainable supply of LBM is significantly higher than the global maritime fleet energy demand. This is also true when comparing the low supply values to the high demand values. When aquatic biomass is included, the lower value of the maximum sustainable supply is five times higher than the higher value of demand in 2030, and 25 times higher in 2050. When aquatic biomass is not included, these factors are 2.5 (times higher in 2030) and 1.5 (times higher in 2050).

In conclusion, when assuming that the full global sustainable biomass potential in 2030 and 2050 is available for maritime shipping, the supply of LBM is more than sufficient to satisfy the global demand of the global maritime fleet.

2.3 Cost analysis

The cost price of LBM as bunker fuel is determined by the following cost factors:
1. Biomass feedstock costs.
2. Capital and operating costs related to the production of biomethane.
3. Liquefaction costs.
4. Transport costs.
5. Bunker infrastructure costs.

In the next paragraphs we will first present an overview of cost price estimations for biomethane at plant, i.e. estimations considering the first two cost factors as listed above (see Section 2.3.1). This is followed by more detailed information on the different underlying cost factors and their potential future development (see Section 2.3.2). The last three costs items, i.e. liquefaction, transport and bunker infrastructure costs, are relevant both for LBM and LSM and will be discussed in chapter 4 where we also compare the costs of different bunker fuel types.

2.3.1 Production costs of biomethane

Table 15 gives an overview of the estimates of biomethane production costs, differentiated by conversion route, as can be found in the literature. The estimations include feedstock costs and represent either current or 2050 costs. For 2030 we were not able to find cost estimations in the literature. For comparability reasons, we have converted the estimations to 2019 USD per MMBtu. In the footnotes to Table 15, specific assumptions in the different studies are highlighted.

Table 15 — Biomethane cost price values (USD_{2019}/MMBtu) at plant as can be found in the literature (current and 2050)

Source	Anaerobic digestion	Gasification
	Current situation	
Billig (2016)		24-63 [a]
BIOSURF (2016)	28-42[b]	
Cucchiella et al. (2015)	25-49[c]	
EA Energianalyse and SDU (2016)	20-27[d]	
CE Delft et al. (2016)	25	
Ecofys (2018)	33	
Gassner and Maréchal (2009)		39-52 [e]
IRENA (2018b)	9-30[f]	
Navigant (2019)	19	33
	2050	
Ecofys (2018)	21	13
Navigant (2019)	15[g]	

[a]: The cost range results from the influence of plant capacity and feedstock use.

[b]: 0.80 EUR/m^3 for a production capacity of 500 m^3/hour and 1.20 EUR/m^3 for a capacity of 80 m^3/hour.

[c]: The cost value of 0.71 EUR/m^3 is for a 1,000 m^3/h biomethane plant using 30% energy crops and 70% livestock slurry. The value of 1.42 EUR/m^3 is for a 100 m^3/h plant using energy crops. Compression and distribution costs are included in these values.

[d]: Upgrading by physicochemical CO_2 removal.
[e]: The lower value is for a 150 MW gasification plant and the higher value for a 20 MW plant. Relatively high conversion efficiencies between 69 and 76% have been assumed, however (Kraussler et al., 2018).
[f]: For a biogas plant size of 2,000 m^3/h. The lower value corresponds with the use of industrial waste as the feedstock, and the higher value with the use of energy crops.
[g]: For a plant size of 200 MWth at current feedstock prices.

Table 16 summarizes the findings.

Table 16 — Summary of biomethane cost price values at the plant gate from literature review

[USD_{2019}/MMBtu]	Anaerobic digestion	Gasification
Current situation	19-49	24-63
2050	15-21*	13*

* Values based on one study each.

For the current situation, the cost price of biomethane from anaerobic digestion is estimated to lie in the range of around 20 to 50 USD/MMBtu and to be lower than for gasification (range of around 25-65 USD/MMBtu). For both processes, production costs are expected to be lower in 2050, with the costs for gasification then being lower than for anaerobic digestion. However, only limited research has been carried out for the 2050 situation.

As will be explained in the following section, future cost reductions will most likely be the result of upscaling: capital expenditure per unit of production capacity will decrease significantly as installed capacities increase. The operational expenditures (OPEX) are expected to stay more or less the same leading to a higher share of OPEX in the overall costs. Feedstock costs, as part of OPEX, are expected to decrease when a shift is made from energy crops and manure to tertiary residues, such as organic waste and sludge.

2.3.2 Detailed information on production cost factors

The capital expenditure (CAPEX) of biomethane production systems primarily consists of the capital costs of the different physical components, which are different for the different main conversion routes. For the anaerobic digestion route, these components are the biogas production system and the upgrading system in which the biogas is upgraded to biomethane. For the gasification route, these are the gasification system and the methanation system (see Figure 4).

The dominant component of the operational expenditure (OPEX) are the feedstock costs. Other OPEX components include maintenance costs, labour costs, electricity and heat consumption, pre-processing costs and disposal costs.

Anaerobic digestion

The CAPEX and OPEX of anaerobic digestion depend on the plant size. Due to economies of scale, the CAPEX and OPEX per m^3 of LBM are much smaller for larger production units. This holds for both anaerobic digestion and gasification. However, few biomass gasification units have yet been built and the degree of the impact of plant size on the costs is therefore less certain. The same holds for cost aspects of the gasification route in general.

Navigant (2019) provides CAPEX and OPEX costs for different plant sizes (500 m^3/h and 1,000 m^3/h) and a upgrading unit of 1,000m^3/h (see Table 17).

Table 17 — CAPEX and OPEX for anaerobic digestion for the current situation (Navigant, 2019)

Technology	Plant size (m^3/h)	CAPEX (MEUR)	OPEX (MEUR/yr)	Biomethane yield (m^3/t dry matter)
Anaerobic digestion	500	5.86	0.60	Feedstock specific
Anaerobic digestion	1,000	9.89	0.63	Feedstock specific
Anaerobic digestion (upgrading unit only)	1,000	2.00	0.11	Not applicable

According to SGAB (2017) both the capital and operational costs (other than the feedstock costs) lie in the same range of 10-15% of total cost. Other costs are likely to consist of feedstock cost. A main cost driver for the non-feedstock related OPEX costs is the heat required for the various production steps. The relative share of non-feedstock related OPEX costs can decline as result of scale effects. For example, SGAB (2017) mentions that staffing requirements are independent of the capacity: whereas these costs might form the dominant cost at smaller capacities, this will be different for larger production units.

Ecofys (2018) gives the composition of CAPEX, feedstock costs and other OPEX for biomethane produced through anaerobic digestion in the current situation and in 2050 (Table 18). The cost reduction between 2050 and today arises from process efficiency improvements, larger digestion units (from < 2 MW units to 6 MW units) and larger upgrading units that process the biogas from multiple digestion units. An increase in feedstock costs has been assumed, because the potential of low-cost biomass residues was thought to be 'significant, yet still limited'. Also, the use of sequential crops[10] is assumed in 2050, which are relatively costly (Ecofys, 2018).

Table 18 — Composition of CAPEX and OPEX of anaerobic digestion in current situation and in 2050 (Ecofys, 2018)

Cost Value	Current situation [a]	2050
Full cost		
CAPEX (MEUR/MW)	5.63	1.84
OPEX excl. feedstock cost (% of CAPEX)	6-10%	6-10%
Levelized cost (EUR/MWh of biomethane)		
CAPEX	41 (43%)	13 (22%)
OPEX excl. feedstock cost	44 (46%)	25 (42%)
Feedstock cost	11 (11%)	22 (37%)
Total cost	**96 (100%)**	**60 (100%)**

[a]: Data for the year 2015.

[10] Triticale and maize silage are assumed to be produced as sequential crops, i.e., "as additional (second) crop before or after the harvest of main crops on the same agricultural land" (Ecofys, 2018).

Tsiropoulos et al. (2018) provide CAPEX figures of anaerobic digestion for the current situation, 2030 and 2050 (see Table 19). The current CAPEX value is lower as the one from Ecofys (2018). Comparing CAPEX reductions over time, Tsiropoulos et al. (2018) give a reduction between today and 2050 of 5-26%, whereas the reduction given by Ecofys (2018) is 67%. However, since the current CAPEX value of Ecofys (2018) is higher, the 2050 estimates of both sources are not that much apart. The CAPEX cost reduction between today and 2030 of Tsiropoulos et al. (2018) is 3-16%. The relative CAPEX cost reduction between today and 2050 is 0.2-0.7% per year (compared to 1.9% in Ecofys (Ecofys, 2018)).

Table 19 — Composition of CAPEX and OPEX of anaerobic digestion in current situation, 2030 and in 2050

Cost Value	Current situation [a]	2030	2050
	Full cost		
CAPEX (MEUR/MW)	3.10	2.60-3.00	2.29-2.93
OPEX excl. feedstock cost (% of CAPEX)	4%	4%	4%

Source: (Tsiropoulos et al, 2018).

[a]: Data for the year 2015.

Energy consumption costs

Typically, 5 to 10% of the energy of the biogas produced in anaerobic digestion systems is needed for heating the digesters — other energy sources could of course also be used for this. Furthermore, the consumption of electricity, which is used to power pumps and monitoring and control systems, is typically 20 to 30 kWh_e per MWh of biogas (IRENA, 2018b).

Gasification

Gasification units are currently less technically mature than anaerobic digestion units. Capital costs are high due to the early stage of development, but significant cost reductions can be expected due to innovations, technology scale-up and continuous deployment. Table 20 provides cost estimates for a first of a kind plant as well as for ‘N^{th} of a kind’ plants of various sizes. Based on this table, a 50% reduction of CAPEX is expected for a large ‘N^{th} of a kind’ gasification plant compared to a first of a kind plant that is five times smaller. OPEX are also expected to decrease by 50%. Navigant (2019) mentions improved plant integration, innovative gas cleaning methods and high-pressure gasification as potential other factors that might contribute to a reduction of overall system costs, but these cost reductions have not been quantified in the OPEX costs as depicted in Table 20.

Table 20 — CAPEX and OPEX for gasification

Technology	Plant size (MW_{th})	CAPEX (EUR/MW_{th})	OPEX ($MEUR/MW_{th}$/year)	Energy efficiency (%)
Gasification (first of a kind)	42	2.83	0.27	64%
Gasification (N^{th} of a kind)	42	2.41	0.25	64%
Gasification (N^{th} of a kind)	84	1.98	0.22	64%
Gasification (N^{th} of a kind)	200	1.4	0.15	75%

Source: (Navigant, 2019).

Table 21 provides the CAPEX and OPEX of gasification in 2050 as estimated by Ecofys (2018). The levelized cost of biomethane produced by gasification in 2050 are 37% lower than the estimated value for biomethane produced by anaerobic digestion. The main reason is the difference in assumed biomethane production yields: 0.55 m^3 of biomethane/kg of feedstock for gasification vs. 0.36 m^3/kg for anaerobic digestion. Also, the operation and maintenance cost and CAPEX of anaerobic digestion are higher (Ecofys, 2018).

Table 21 — Composition of CAPEX and OPEX of gasification in 2050 (Ecofys, 2018)

Cost Value	2050
Full cost	
CAPEX ($MEUR/MW_{th}$)[11]	1.64
OPEX excl. feedstock cost (% of CAPEX)	5%
Levelized cost (EUR/MWh of biomethane)	
CAPEX	13 (34%)
OPEX excl. feedstock cost	12 (32%)
Feedstock cost	13 (34%)
Total cost	**38 (100%)**

Navigant (2019) estimates the CAPEX of a first of a kind gasification plant at 2.83 $MEUR/MW_{th}$. Assuming a CAPEX of 1.64 MEUR/MW from Ecofys in 2050, the cost reduction would be 42%, or ~1.2%/year. Interpolating for 2030, the CAPEX of a gasification plant in 2030 would be ~2.3 MEUR/MW.

Upgrading costs

According to CE Delft et al. (2016) biogas upgrading costs are 0.2-0.31 EUR/m^3 biomethane, but these decrease with increasing scale to 0.13 EUR/m^3 at a production capacity of 2,000 m^3/hour. This is comparable to IRENA (2018b), which shows a reduction of 0.2-0.3 USD/m^3 of biomethane at a production capacity of 250 m^3/hour to 0.1-0.15 USD/m^3 at 2,000 m^3/hour. In the case of smaller upgrading units, the upgrading cost can reach 1.0 USD/m^3.

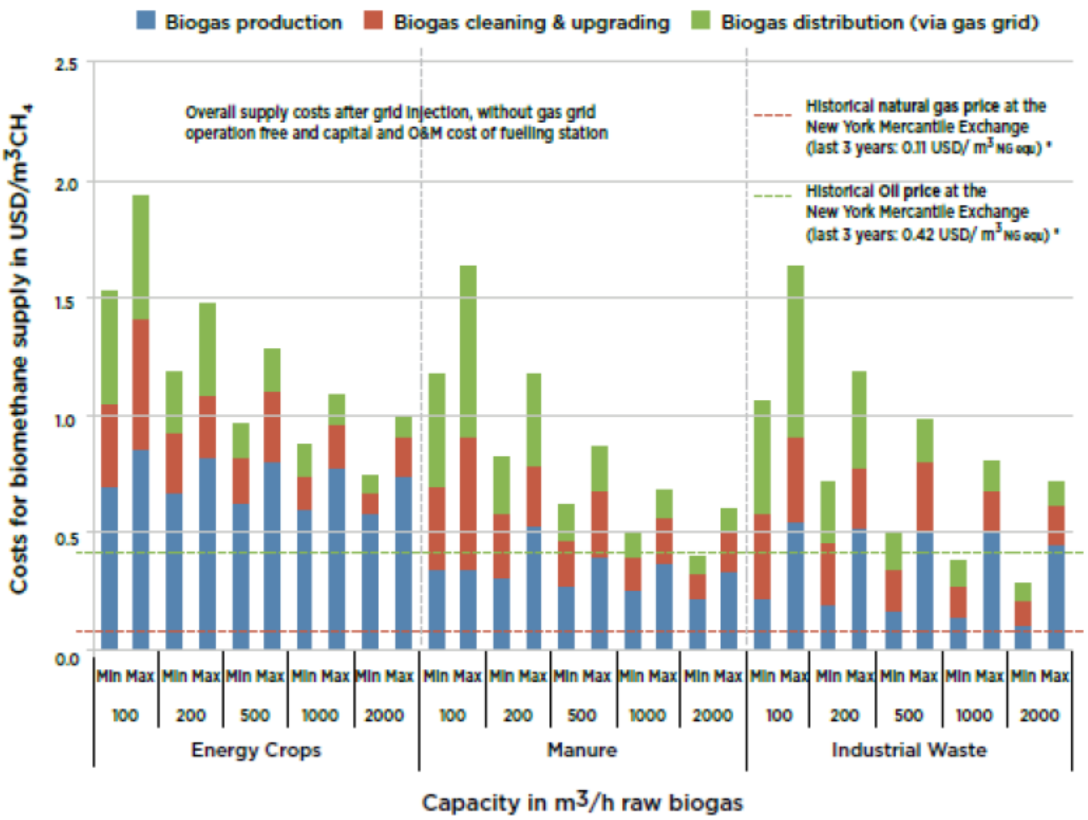
The upgrading costs can also be considered to include the (capital and operational) cost of transport of the raw biogas to the upgrading facility. Navigant (2019) estimates the costs for biogas pipelines at 5 EUR/MWh (0.06 EUR/m^3).

Feedstock costs

According to Lambert (2017), biomethane produced from manure and industrial waste processed in larger installations are nearly competitive, but biomethane plants using expensive feedstocks are uncompetitive without any governmental support closing the gap. However, due to the large variety in potential feedstock for anaerobic digestion plants, feedstock costs could range from negative (in case of waste streams that have a disposal cost) up to 100 EUR/ton for straw (SGAB, 2017). Figure 11 shows the current cost structure of biomethane production for various feedstock groups and for different scales of production.

[11] Based on the source it was not clear to what extent whether this figure represented MW_{th} (thermal energy of biomass). We have assumed this is the case, which has resulted in a somewhat lower figure than when $MW_{biomethane}$ would have been assumed.

Figure 11 — Total production costs for biomethane from anaerobic digestion by feedstock and size for the current situation



Source: (IRENA, 2018b).

In Table 22, the costs of different biomass feedstocks for the current situation, 2030 and 2050 are indicated, based on various literature sources.

Table 22 — Feedstock costs per feedstock type (current, 2030 and 2050)

Feedstock category	Feedstock type	Current (EUR Cent/kWh)[3]	2030 (USD/GJ) [2]	2050 (EUR/tonne dry matter)[1,4]
Energy crops	Maize, sugar cane, wheat	8.5	4-80	78-90
Agricultural residues	Crop residues	8.5	3-8	47-61
	Manure	6.3	n.a.	5-50
Woody residues	Bark, branches, tops, early thinnings	4.9	1-20	92
Residual and post-consumer waste	MSW	6.5	n.a.	12
	Wood waste	n.a.	1-20	12

[1]: Navigant (2019).
[2]: IRENA (2018b). Includes the costs of production, collection and transport of biomass.
[3]: Trinomics et al. (2019).
[4]: Ecofys (2018).

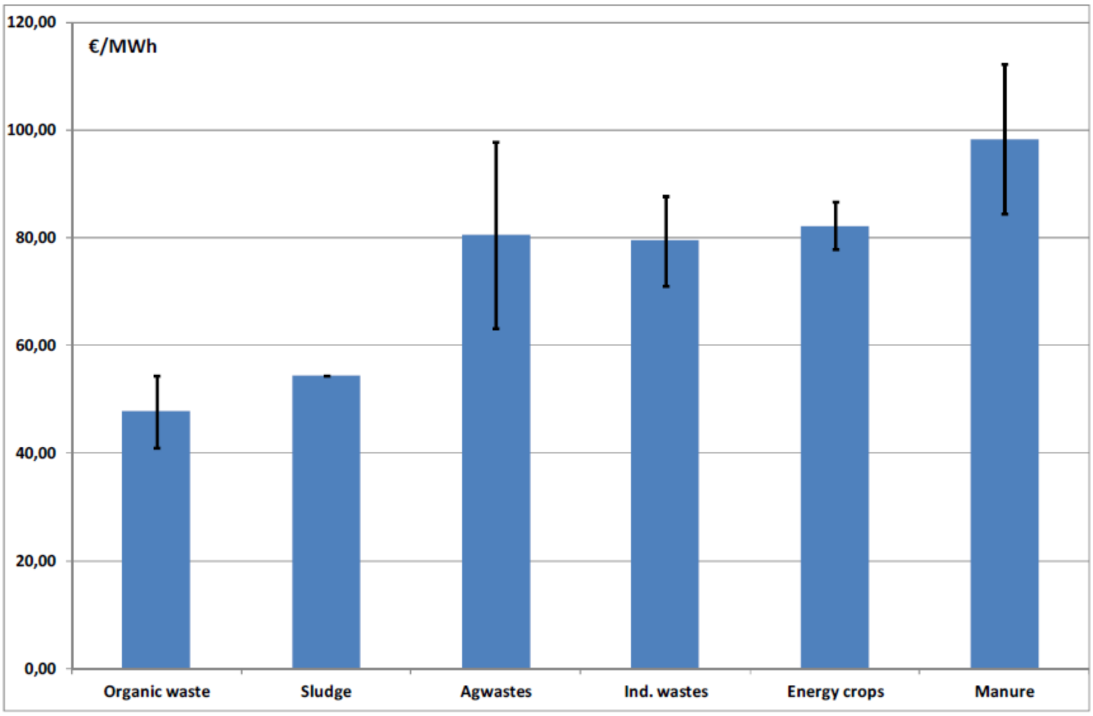
Woody residues can only be converted to biomethane through gasification. The other feedstocks can currently only be used in digesters. With supercritical water gasification, digestible feedstocks could also be gasified, but cost figures on this new technology are still lacking. Here we focus our attention on anaerobic digestion and conventional (thermal) gasification, the technologies that also have been included in the availability analysis of Section 2.2.

In Figure 12 the production costs of biomethane from various feedstocks are depicted. It shows that the costs can vary substantially, depending on the feedstock: up to 50 EUR/MWh, when comparing organic waste to manure, amounting to ~50% of the total production cost.

This can be explained by the different cost prices of the feedstocks, but also by other indirect effects of the different feedstock types on the OPEX: The choice of feedstock affects for example the value or cost of disposal of the digestate. Furthermore, the gas yield from the variety of substrates may in practice range from 150 to 600 m^3/ton dry substance (SGAB, 2017). A higher production yield results in a lower feedstock input volume per m^3 of liquid biomethane.

According to a survey among biogas plant operators in the EU (BIOSURF, 2016), the contribution of feedstock costs lies in a range of 3 to 60 EUR/MWh.

Figure 12 — Cost of production of biomethane from different feedstocks in the current situation



Source: (SGAB, 2017).

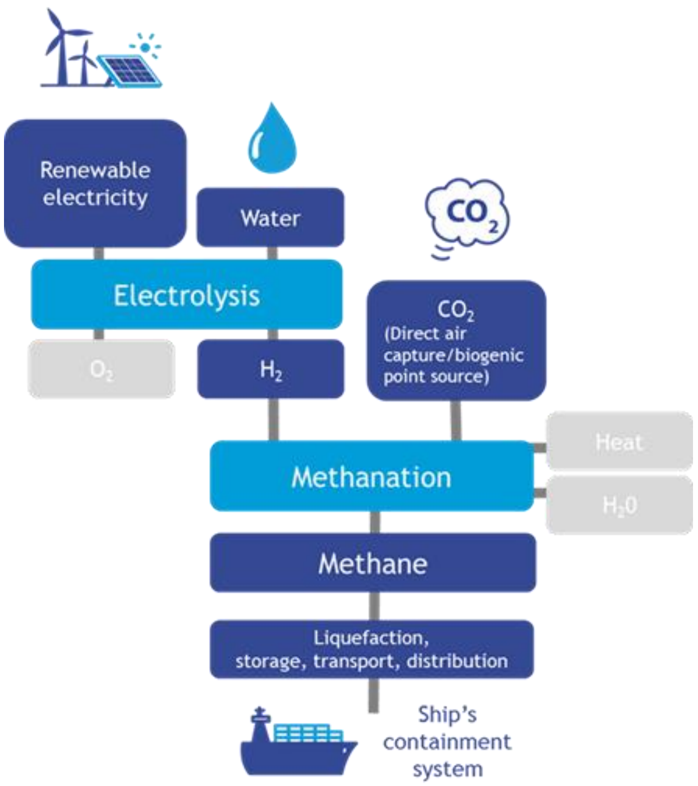
3 Availability and cost price of liquefied synthetic methane (LSM)

This section identifies the essential elements for the potential conversion routes of liquefied synthetic methane (LSM) and analyses their availability and their costs. We will analyse the availability of LSM in Section 3.2 and cost price of LSM in Section 3.3.
The conversion routes that are taken into account are presented in Section 3.1, in the scoping analysis.

3.1 Scoping analysis

We define synthetic methane as methane derived from synthesis of CO_2 and hydrogen. Synthetic methane is also known as power to gas or e-methane due to the fact that the source of production relies on electricity and due to its substitutable properties with natural gas, but for consistency purposes, we shall use the term LSM throughout this report. A schematic overview of the conversion routes is depicted in Figure 13.

Figure 13 — Potential conversion route for the production of LSM



Electricity and water are feedstocks to produce hydrogen via the process of electrolysis. In a methanation process, the produced hydrogen can, using CO_2, be converted into methane. For storage and use by ships, the methane needs to be liquefied.

For each step in the production various options exists. These options will be described in more detail in the next sections and will be limited to the options included in the scope of this study.

3.2 Availability analysis

The analysis of the availability of LSM differs fundamentally from the analysis of the availability of LBM. In contrast to the biomass feedstocks required for the production of LBM, the main inputs required for the production of renewable LSM (electricity, water and CO_2) are technically not restricted. The *effective* technical potential of LSM will be determined by the availability of (excess) renewable electricity which is very difficult to project on a global level. For this reason we decided to determine the renewable electricity required for covering the expected future energy demand of shipping by means of renewable LSM only.

This section zooms in on the availability of renewable electricity, water, and CO_2 as well as the main relevant processes which are electrolysis, methanation and liquefaction.

3.2.1 Availability of renewable electricity

Electricity is an essential input for the production of sustainable LSM. Electricity is used for the production of hydrogen by means of electrolysis (Figure 13) and is also required for capturing of CO_2, the methanation process, and, depending on the technology, also for the liquefaction process. While LSM can in principle be produced with the current electricity mix — a mix including a non-renewable share of electricity — LSM can only be used in a decarbonised shipping sector if it is produced by means of renewable electricity.

Power-to-gas, including power-to-methane, is also considered as an option to store surplus renewable power from wind or solar energy. This however requires, as will be discussed in more detail below, the establishment of a production process that can cope with load changes (Gorre, 2019). And excess renewable electricity is also not expected to be sufficient to cover the power demand of synthetic fuel production and is probably not be an economically viable option due to the relative low full load hours at which a plant could be operated (Frontier Economics, 2018).

Dedicated renewable power plants would have to be used instead, requiring additional investments, leading to relative higher electricity prices, and to additional land use.

Regarding the future availability of renewable power, there are many different projections. The differences lie mainly in assumptions about the ambition of global climate policy. We shall look into the following three reputable publications which have been developed or adopted by international organisations.

One authoritative report is “Global energy transformation — A roadmap to 2050” (IRENA, 2019e). According to that report, the renewables share in electricity generation was around 20% in 2010. Using 2010 as the baseline, (IRENA, 2019e) has developed two scenarios, one is the Reference Case where the future projections are predicted based on historical growth of renewable energy share in electricity and the REmap[12] Case assumes that that supportive policy and frameworks will be implemented to limit the average global surface temperature increase to well below 2°C by 2100 and is thus commensurate with the ambitions of the Initial IMO strategy on reduction of GHG emissions from ships.[13] This scenario includes the deployment of low carbon technologies based largely on renewable energy and energy efficiency. Under these assumptions, the share of renewable electricity generation will increase from approximately 24 in 2016 to 57% in 2030 and to 86% by 2050. In absolute terms renewable electricity generation would account for around 20,400 TWh and 47,700 TWh in 2030 and 2050 respectively (see Table 23).

The International Energy Agency (IEA) has developed Energy Technology Perspectives (ETP) for the sectors energy supply, buildings, industry and transport (IEA, 2017a). Two climate mitigation pathways have been developed in this context: the '2°C Scenario' and the 'Beyond 2°C Scenario'. The '2°C Scenario' is the ETP's central climate mitigation scenario and lays out an energy system pathway and a CO_2 emissions trajectory consistent with an at least 50% chance of limiting the average global temperature increase to 2°C by 2100 (IEA, 2017a). The 'Beyond 2°C Scenario' explores how far deployment of technologies that are already available or in the innovation pipeline could take the world beyond the '2°C Scenario'. Technology improvements and deployment are thereby assumed to be pushed to their maximum practicable limits across the energy system in order to achieve net-zero emissions by 2060 and to stay net zero or below thereafter, without requiring unforeseen technology breakthroughs or limiting economic growth (IEA, 2017a). Considering both scenarios, gross total electricity production is expected to amount to 31,000-31,400 TWh in 2030 and 42,500-44,300 TWh in 2050 and gross renewable electricity production to 14,500 TWh and 28,700-31,800 TWh in 2030 and 2050 respectively.

As part of IPCC's Fifth Assessment Report, four representative concentration pathways, RCP2.6; RCP4.5; RCP6.0; RCP8.5, named according to their 2100 radiative forcing levels, have been selected to represent a broad range of climate outcomes. After the Paris Agreement an additional RCP pathway, i.e. RCP 1.9 has been developed. From these five pathways, RCP2.6 and RCP1.9 are the concentration pathways for which it is likely that the temperature increase stays at/below 2°C in 2100. Five Shared Socio-Economic Pathways (SSPs) have been developed to complement the RCPs. They describe potential major global developments (population development, urbanization and economic development (GDP)) that together will lead to different challenges for mitigation and adaptation to climate change (Riahi et al. 2017). The socio-economic information of the SSPs have been used as input for runs of different integrated assessment models to determine key variables (like e.g. energy consumption for different sectors) that match the different RCPs. Table 23 gives the expected power generation and the share of renewable electricity production for RCP2.6 and RCP1.9 scenarios, with the range reflecting the different SSPs applied.[14]
As Table 23 shows, for the RCP2.6 scenarios it holds that renewable electricity production ranges from 6,300 to 13,100 TWh and from 22,200 to 28,100 TWh in 2030 and 2050 respectively whereas for the RCP1.9 scenarios from 8,100 to 14,700 TWh in 2030 and 31,200 to 49,100 TWh in 2050.

[12] REmap = renewable energy roadmap analysis.

[13] The REmap suggests that the total share of renewable energy must rise to around two-thirds by 2050 to meet the Paris agreement goal of limiting the surface temperature below 2°C. Under this REmap Case scenario, 65% of the total final energy consumption will be generated using renewable energy sources. It was also assumed that the share of electricity rises to 40% of the total final energy consumption by 2050 and assumed that there will be a 2.8% reduction in terms of energy intensity improvement compared to 2015.

[14] RCP2.6 has been modelled for SSP 1, 2, 4 and 5 and the RCP 1.9 for SSP 1, 2 and 5.

Table 23 — Projections of global renewable electricity production (TWh)

		2030			2050		
		Total	RE	RE share	Total	RE	RE share
2°C scenarios	IEA, 2°C Scenario	31,400	14,500	46%	42,500	28,700	67%
	IPCC RCP2.6 scenarios	37,500-43,000	6,300-13,100	17-31%	43,800-51,600	22,200-28,100	43-64%
(well) below 2°C scenarios	REmap Case	35,900	20,400	57%	55,200	47,400	86%
	IEA, Beyond 2°C Scenario	31,000	14,500	47%	44,300	31,800	72%
	IPCC RCP 1.9 scenarios	31,600-33,300	8,100-14,700	24-47%	35,300-69,900	31,200-49,100	70-88%

Source: (IRENA, 2019a) (IIASA, 2018); (IEA, 2017a).

Differentiating between 2°C-scenarios and (well) below2°C-scenarios, the projections renewable electricity production can be summarized with the following ranges:
— 2°C scenarios: 6,300-14,500 TWh in 2030 and 22,200-28,700 TWh in 2050;
— (well) below 2°C scenarios: 8,100-20,400 TWh in 2030 and 31,200-49,100 TWh in 2050.[15]

Conclusion

The generation of renewable electricity is growing fast, but currently most of the electricity is used directly, rather than to produce fuels such as synthetic methane. In order to produce large quantities of synthetic methane, substantial investments in renewable, dedicated electricity capacity would be needed.

3.2.2 Availability of hydrogen

The renewable electricity is used to produce hydrogen through electrolysis of water. Electrolysers can be categorized based on the temperature of the process namely low-temperature electrolysers (50-80°C) and high temperature electrolysers (700–1,000°C). There are two technologies for low-temperature electrolysis, Alkaline Electrolysis Cells (AEC) and Proton Exchange Membrane (PEM), and one for high temperature analysis: Solid oxide electrolysis cell (SOEC) (Table 24).

Table 24 — Electrolysis technologies

Class	Technology	
Low temperature electrolysis	Alkaline electrolysis cells (AEC)	Proton exchange membrane (PEM)
High temperature electrolysis	Solid oxide electrolysis cell (SOEC)	

AEC and PEM electrolysers are commercially available and can thus be considered to be technologically mature (TRL 9). SOEC is still in the developmental stage (Frontier Economics, 2018). There are pilot plants in Dresden, Germany and in Mellach, Austria (Sunfire, 2019).

[15] We interpret the renewable electricity scenarios as not accounting for the production of e-fuels to be used in the transport sector, but this is not entierly clear. (IEA, 2017a) for example differentiates between oil, natural gas, electricity, biomass and hydrogen regarding the final energy demand of the transport sector, but it is not clear whether this is green or blue hydrogen.

Table 25 compares the three technologies on:
— current/expected CAPEX and OPEX;
— lifetime (system and stack) and replacement cost of the stack;
— current/expected conversion efficiency (electricity to hydrogen and conversion yield);
— technological readiness level/maturity.

Table 25 — A comparison of electrolysis technologies, 2017, 2030 and 2050

Technology	Low temperature						High temperature		
	AEC			PEM			SOEC		
Indicators	2017	2030	2050	2017	2030	2050	2017	2030	2050
Capital cost (EUR 2015/ kW_e)	600-2,600	400-900	200-600	1,900-3,700	300-1,300	200-600	400-1,000	400-1,000	400-800
Operational & maintenance cost (% to their investment cost)	2-5%	2-5%	-	2-5%	2-5%	-	2-3%	2-3%	-
System life span (years)	25	30	-	20	30	-	10-20	10-20	-
Stack life span (1,000h)	75	95	-	62	78	-	<90	<90	-
Stack replacement cost									
Assumed electricity to hydrogen efficiency (%)	58	67	71	58	67	71	77	81	90
Electricity consumption (kWh/kg in 2015)	58	50	47	58	50	47	38	37	37
Efficiency (LHV) (Electricity to methane)	50	66	85	50	66	85	78	92	92
TRL (Assumption)	8-9	9	9	7-8	9	9	5-7	9	0
Maturity	Commercial			Commercial but small scale			Demon-stration	Commercial	

Source: (Selma, et al., 2018), (Imperial College London, 2017), (Frontier Economics, 2018), (E&E, 2014), (Cerulogy, 2017), (Adelung & Kurkela, 2018).

Efficiency

Currently, electrolysers achieve their best efficiency under steady currents. PEM is better suited to operate at partial loads and to deal with fluctuating energy supply than AEC.
All the technical factors that contributes to the efficiency of these two electrolysers technology has been depicted in Table 26. The electricity to hydrogen efficiency provided in the table below is based on lower heating value and If the heat released by each of these processes is recovered and used, production efficiency can increase up to 71% by 2030 (Cerulogy, 2017).

Table 26 — AEC and PEM indicators based on 2015-2017 data

Indicators	AEC	PEM
Electrolyte	Aq.potassium hydroxide	Polymer membrane
Cathode	Ni, Ni-Mo alloys	Pt, Pt, Pd
Anode	Ni, Ni-Co alloys	RuO2, IrO2
Current density (A cm^{-2})	0.2-0.4	0.6-2.0
Voltage efficiency (%)	62-82	67-82
Operating temperature (°C)	60-80	50-80
Operating pressure (bar)	< 30	< 200

Indicators	AEC	PEM
Production rate (m^3 H_2 h^{-1})	< 760	< 240
Gas purity (%)	> 99.5	99.99
Cold start time (min)	< 60	< 20
System (start time)	Seconds	Milliseconds
Stack life time (Years)	7-10	2-7
Systematic lifetime (years)	20	20
Electricity to hydrogen efficiency (%)	58-71	58-71
TRL Level	9	7-8
Flexibility (fluctuating renewable electricity)	Yes	Yes

Source: (Selma, et al., 2018), (Cerulogy, 2017), (IRENA, 2018a) and (Adelung & Kurkela, 2018).

Conversion efficiency

The efficiency of low temperature electrolysis is currently at 43-69% (Selma, et al., 2018), 58% on average (Cerulogy, 2017). According to (Cerulogy, 2017), the efficiency can be improved especially when the waste heat of methanation is used. This would make it possible for the efficiency to improve from 58% on average in 2015 to 67% in 2030 and reach up to 71% by 2050.

Capacity

To date, about 2-4% of global hydrogen supply is produced via electrolysis (IEA, 2019d) (IRENA, 2018a). Most of this is probably produced with AEC, which are larger scale than PEM and require lower costs (Leeuwen, 2018), (Maria Taljegard, 2016).

Conclusion

Most electrolysers currently are of the AEC type. Its main advantages compared to PEM are low capital costs, availability of large plants sizes and long life spans. It is technologically also more mature than SOEC **(Selma, et al., 2018)**. PEM currently requires higher capital costs — mainly due to the need for expensive catalysts — and the high pressures required are more complex than AEC **(Imperial College London, 2017)**. However, it could become competitive with AEC in one or two decades **(International Journal of Hydrogen Energy, 2017)**. SOEC requires less energy than low temperature technologies, but can cope less well with fluctuating energy supply. It is expected to become commercially available in one or two decades.

Electrolysis is currently not used to produce hydrogen in large quantities. Electrolysis currently accounts for 2-4% of global hydrogen production (IEA, 2019d; IRENA, 2018a). In order to produce large quantities of synthetic methane, investments in electrolysis capacity would be needed.

3.2.3 Availability of water

Hydrogen production requires water. Methane has an overall higher water input for electrolysis compared to methanol or syngas, because the methanation reaction requires more hydrogen than the methanol synthesis (Ramboll et al., 2019). It requires 4.73 kg of water per kg (Ramboll et al., 2019).

Electrolysis of water requires fresh water, because the electrolysis of seawater generates chlorine as an unwanted by-product.[16] This means that freshwater either has to be available or seawater needs to be desalinated. Desalination is an established technology that is commercially available and the application is growing rapidly (Jones, et al., 2019). Hence, water availability is not considered to be a constraint to the production of LSM. According to (Frontier Economics, 2018), the costs of supplying water are negligibly low, even in countries where the water has to be obtained from desalination plants. To cover the water demand of the electrolysis process it is, to a certain extent, possible to re-use the water which is generated as a by-product of the methanation process with the help of a purification plant. This could further reduce the costs of water.

3.2.4 Availability of carbon dioxide

Carbon dioxide can either be captured at point sources or it can be captured from ambient air by means of direct air capture (DAC). Only carbon capture from biogenic point sources and DAC can be considered to be carbon neutral. This section discusses both, carbon capture from point sources, in general and with special focus on biogenic CO_2, as well as DAC.

Carbon capture and utilization (CCU): technology readiness

The CO_2 capture processes and systems are usually categorized according to their transformation routes (Ramboll et al., 2019). Table 27 indicates the various CO_2 transformation categories and their respective processes.

Table 27 — CO_2 transformation routes and process description

Transformation route	Process description
Chemical (non-hydrogenative)	Chemical conversion of CO_2 without hydrogen as a co-reactant
Chemical (hydrogenative)	Chemical conversion of CO_2 with hydrogen as a co-reactant
Biological	CO_2 conversion by photosynthesis
Electrochemical	Reduction of CO_2 carbon atom by adding electrons
Photochemical	Reduction of CO_2 carbon atom by solar energy
Inorganic	Fixation of CO_2 in inorganic compounds

Source: (Ramboll et al., 2019).

(Ramboll et al., 2019) analyzed more than 130 different CCU application options from different routes and functionalities. Out of this 130 application options, 48 have a TRL of 7 or higher, of which 19 are commercially available (TRL 9). Most of the technologically mature routes are chemical non-hydrogenative or chemical hydrogenative processes, although there are also some inorganic CCU routes with a high TRL. Each transformation route mentioned in the table above satisfies the purpose of capturing carbon for a certain product such as ethanol, polyols for polyurethane (PU) foams production, etc. For synthetic fuels production, chemical hydrogenative transformation route has been identified as the most suitable route (Ramboll et al., 2019). Hence, carbon capture and utilization using the chemical hydrogenative transformation route for the production of synthetic methane is considered to be a mature technology.

[16] Research is ongoing into catalysts that allow the use of seawater in hydrogen production, but this is still in the research phase. See e.g. (Vos, et al., 2018).

A pilot demonstration plant in Falkenhangen, Germany has successfully produced synthetic methane generated by wind turbines and using CO_2 that is sourced from a bio-ethanol plant. In March 2019, an average of 14,500 kWh synthetic methane was produced per day.[17]

Carbon capture at point source: CO_2 availability

A techno-economic analysis performed by (Naims, 2016) indicates that the global annual CO_2 supply from point sources that could be used for carbon capturing is currently approximately 12.7 Gt. The degree of CO_2 concentration of the flue gas, the purity of the CO_2 captured and the technology applied for capturing the CO_2 are thereby the main determinants of the capture costs (Ramboll et al., 2019):

- Ammonia synthesis, hydrogen production and natural gas extraction are considered industrial processes which emit highly pure CO_2 and a small share of these emissions are already captured today. Currently, these sources account, on a global scale, for around 250 Mt of CO_2 annually (Naims, 2016).
- Biogas plants, especially biogas upgrading plants, emit relatively highly concentrated CO_2, however still at a limited scale. In North America and Brazil, these CO_2 emissions are estimated to amount to around 20 Mt annually (Naims, 2016).
- Fossil fuel power stations emit a large amount of CO_2 annually (around 10 Gt), but with 3 to 15% the CO_2 concentration of the flue gas is however relatively low, leading to higher capture costs when compared to the above mentioned processes (Naims, 2016).
- Energy intensive industries, like e.g. cement production and iron and steel production also emit a significant amount of CO_2, globally around 3 Gt annually. The cement production thereby features with 14-33% a relatively high flue gas CO_2 concentration (Naims, 2016).

Direct air capture

Direct air capture (DAC) extracts CO_2 from ambient air. DAC systems have the advantage that they do not depend on CO_2 point sources; they can therefore be applied anywhere, could be integrated into an electrolysis/methanation plant (saving CO_2 transportation costs), can be upscaled whenever desired and are not dependent on the future development of the CO_2 point sources.

The energy demand and separation costs of DAC systems are however higher if compared to systems that capture carbon at point sources. This can be explained by the relative low CO_2 concentration in ambient air (around 0.04% vs. for example 3-10% and 12-15% in flue gasses of gas and coal power plants respectively (Naims, 2016)).

Another disadvantage of DAC systems is their relative large geographical footprint (Frontier Economics, 2018). A facility that captures 1 Mt of CO_2 would for example require 2 km^2 of land (National Academics of Sciences, Engineering, and Medicine, 2018). But this might be more an issue if DAC was used for carbon capture and storage on a large scale.

DAC is technically feasible. Different technologies have been developed and demonstration plants have been build, some even at commercial scale. The technology can be considered near to commercialization (GlobeNewswire , 2019).[18]

[17] Store & GO : The German demonstration site at Falkenhagen

[18] CO_2 captured from air is intended to be used for the flooding of oil fields to extend the economic life of their economic life.

In DAC systems, chemical sorbents are used to remove CO_2 as ambient air flows over an air contactor. After CO_2 is captured, the material used for separation requires regeneration. (National Academics of Sciences, Engineering, and Medicine, 2018).
DAC involves two generic approaches, one being a solvent-based method and another being solid-sorbent-based:

- In the solvent-based approach, a strong alkaline solution is used to capture CO_2 from the air in a simple acid-base reaction that results in the formation of a stable carbonate, which then has to be heated in an oxy-fired kiln to release high-purity CO_2 and lime to be recycled throughout the process,
- In a solid-sorbent-based DAC process, CO_2 from the air binds to a sorbent using a gas-solid contactor. An approach based on both heat and vacuum is used to desorb the CO_2 from the sorbent, producing a concentrated stream of CO_2. This system is subsequently cooled to begin the cycle again (National Academics of Sciences, Engineering, and Medicine, 2018). This process to release the CO_2 captured is also referred to as temperature swing adsorption (TSA).

According to (Frontier Economics, 2018), the most established DAC technology is temperature swing adsorption (TSA). Table 28 captures the key indicators for direct air capture by means of TSA and for capturing of biogenic CO_2 from point sources. The data for biogenic CO_2 sources is based on the data from post and pre-combustion systems that could separate CO_2 from the flue gases produced during the production of the primary fuel.

Table 28 — Average energy use estimates for direct air capture and for CO_2 capture from biogenic point sources

Source	Concentration of CO_2	Electricity demand ($MJ/kgCO_2e$)	Heat demand ($MJ/kgCO_2e$)	CAPEX (Euro/tonne CO_2)	OPEX (% of investment cost)	TRL
Direct air capture (TSA)	0.04%	0.9-1.29	4.19	41-2,086	1.5-4%	7
CCU	10-100%	0.03-0.11	1.3-3.3	< 20	-	8-9

Source: (Cerulogy, 2017) (Frontier Economics, 2018) (IEAGHG, 2016) (Karin Ericsson, 2017) and (Mahdi Fasihi, 2019).

Conclusion

About 0.198 kg of CO_2 are required per kWh of methane (ludwig bölk systemtechnik, 2016). This means that approximately 665-780 Mt CO_2 and approximately 560-1,320 Mt of CO_2 would be required for the production of an amount of LSM that could cover the entire shipping sector's expected energy demand in 2030 and 2050 respectively (see Table 30).

It can thus be concluded that CO_2 from point sources is sufficiently available, but so far only captured to a small extent. With stricter climate policies, the availability might however decline in the long run. Regarding biogenic CO_2 point sources, it can be concluded that, at least today and in the near future, they can contribute only to a limited extent to the production of sustainable LSM.

Given the possibility of direct air capture, this however does not mean that the availability of CO_2 is a limiting factor for the production of sustainable LSM – the limiting factor is rather the availability of DAC.

3.2.5 Methanation and liquefaction

Methane can be produced from H_2 and CO_2/CO by the process of catalytic or biological methanation. During the time of the study, the methanation process is largely based on catalytic (thermochemical) methanation since biological methanation has a lower overall efficiency. This results in the need of larger reactors due to lower rates of methane formation, thus making biological methanation not suitable for large scale production plants that needed to supply liquefied synthetic methane for maritime energy demands. This led us to focus primarily on catalytic methanation for our further analysis.
Methanation of CO_2 is an exothermic reaction in which H_2 and CO_2 react to form CH_4 and H_2O. The most widely accepted mechanism of the methanation reaction is the combination of an endothermic reversed water gas shift (RWGS) reaction and an exothermic CO methanation (Stangeland, et al., 2017)

The methanation reaction, also called the Sabatier reaction, is highly exothermic which is why a good temperature control in the reactor is crucial to prevent thermodynamic limitation and catalyst sintering (Götz, et al., 2016).

In order to meet this limitation, several steady state reactors have been developed namely (Götz, et al., 2016):

1. Fixed-bed reactors.
2. Fluidized-bed reactors.
3. Three phase reactors.
4. Structured reactors.

Fixed-bed reactors and fluidized-bed reactors are established technologies and commercially available technologies used in industrial applications such as production of synthetic natural gas from coal or wood and ammonia synthesis, while three-phase and structured reactors are still in the development stage (Götz, et al., 2016).

Fixed-bed reactors are well suited for large scale methanation plants (> 100 MW) while fluidized-bed reactors and three phase methanation reactors are best suited for average plant sizes, with the PtG chain requiring concepts optimised for smaller plant sizes and intermittent or dynamic operation (Götz, et al., 2016).

Globally, very few commercial methanation plants have been built so far, the number of pilot and demonstration plants, however, is rapidly increasing (see (Thema, et al., 2019) for an overview).

The efficiency of catalytic methanation varies from 70–83% (Selma, et al., 2018) based on lower heating value.

Liquefaction of methane

Methane has a boiling point of -162°C which means that it has to be cooled down to -162°C to become liquid. Liquefaction of methane is therefore an energy intensive process. Based on the performance evaluation of real life liquefaction terminals, the energy demand of the process is assessed to be up to 10% of the supplied natural gas (Pospisil & Charvat, 2019). Table 29 shows the specific power consumption for different liquefaction processes. Next to the type of process, the energy consumption of the process is also determined by the size of the plant. Generally, the larger the plant, the lower the specific consumption of electricity.

According to (Pospisil & Charvat, 2019) there are three principles of NG liquefaction technologies, namely cryo-generators, cryogenic liquids and cascade cycles. Among several factors one of the main factors influencing the selection of the technology is, if the system has to be built offshore or onshore.

The cascade cycle and its variants are the most used technology in large LNG plants. This technology uses a cascade of heat exchangers, each with a different medium. All the media which have different boiling points are liquefied by compression with the last medium in the cascade having the boiling point below that of NG (Pospisil & Charvat, 2019).

Table 29 depicts the specific compression power required together with the capacity of specific liquefaction plants working with cascade cycles.

Table 29 — Liquefaction process and their corresponding specific compression power depending on plant capacity

Process (type of liquefaction plants)	Specific compression power (kWh/kg_{LNG})	Capacity of respective plant (Mt per year)
Pure refrigerant cascade	0.29-0.35	5.2
Mixed fluid cascade (MFC)	<0.25	4.3

Source: (Pospisil & Charvat, 2019).

From Table 29, we conclude that deployment of cascade systems would result in a specific compression power of 0.25–0.35 kWh/kg_{LNG}. We have taken the average specific compression power of 0.30 kWh/kg_{LNG} to calculate the renewable electricity demand as depicted in Table 30.

3.2.6 Summary

This section first compares the maritime energy demand with the projected production of renewable electricity and the amount of LSM that can be produced from renewable electricity. It then summarises the technical and capacity constraints to produce sufficient quantities of LSM.

The most important factor that plays a role for the amount of LSM that can be produced from renewable electricity are the conversion efficiencies of the three important technical components namely electrolysis, methanation plants and liquefaction. For electrolysis, the lower value of the conversion efficiency range depicted in the Table 25 has been taken into account for 2015 and it has been assumed that the efficiency increases through technological development over time. The similar methodology has been applied for methanation where the conversion efficiency progresses from 78 to 81% over time, while the conversion efficiency of liquefaction stays the same (70% based on the specific compression power of 0.30 kWh/kg_{LNG}) since the cascade systems are technologically well matured and widely applied. During our research, we did not come across any specific indication that the conversion efficiency of the cascade systems will improve over time.

Table 30 compares the (expected) energy demand of the world fleet with the renewable electricity that would be required to meet the world fleet energy consumption with LSM.

The 2015 marine energy demand is based on (CE Delft, 2018a) and for future marine fuel and energy consumption of the fleet are based on (Öko-Institut, CE Delft and DLR, ongoing), high and a low value for marine energy demand has been used, the high value indicating the business as usual scenario while the low value indicating the reduction scenario.
The reduction scenario relies on many factors the two most important being assumed transport work development for ships and the ship's operational and technical efficiency improvement in the coming years.

Table 30 — Electricity demand for electrolysis, methanation and liquefaction for 2015, 2030 and 2050 under the high (BAU) scenario and low (reduction) scenario

Year	Total energy demand shipping (EJ)	Conversion efficiency electrolysis (%)	Electricity demand for hydrogen production (EJ)	Conversion efficiency methanation (%)	Electricity demand, including electrolysis and methanation (EJ)	Conversion efficiency liquefaction (%)	Electricity demand, including electrolysis, methanation and liquefaction (EJ)
2015	10.7	58	18.8	78	24.1	70	34.5
High (BAU) Scenario							
2030	14.2	67	21.2	81	26.2	70	37.4
2050	23.2	71	32.7	85	27.8	70	39.7
Low (Reduction) Scenario							
2030	12.1	67	18.1	81	22.3	70	31.9
2050	10.2	71	14.4	85	12.2	70	17.4

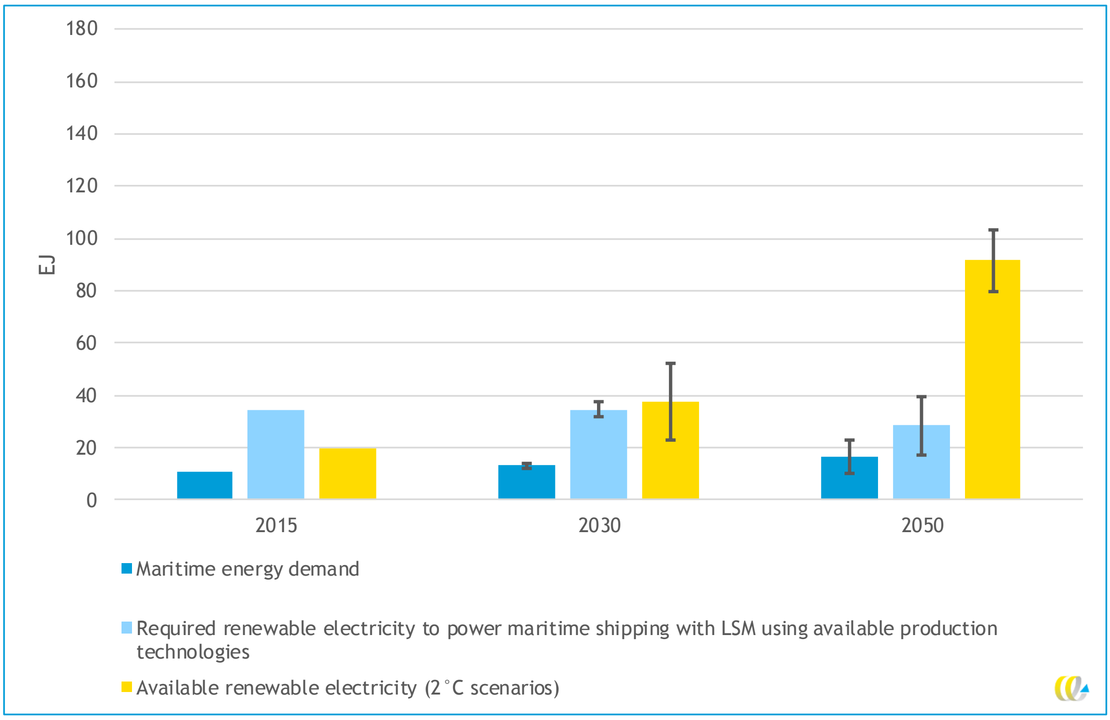
Source: (CE Delft, 2018a), (Öko-Institut, CE Delft and DLR, ongoing), (Cerulogy, 2017), (Selma, et al., 2018) and (Blanco, et al., 2018).

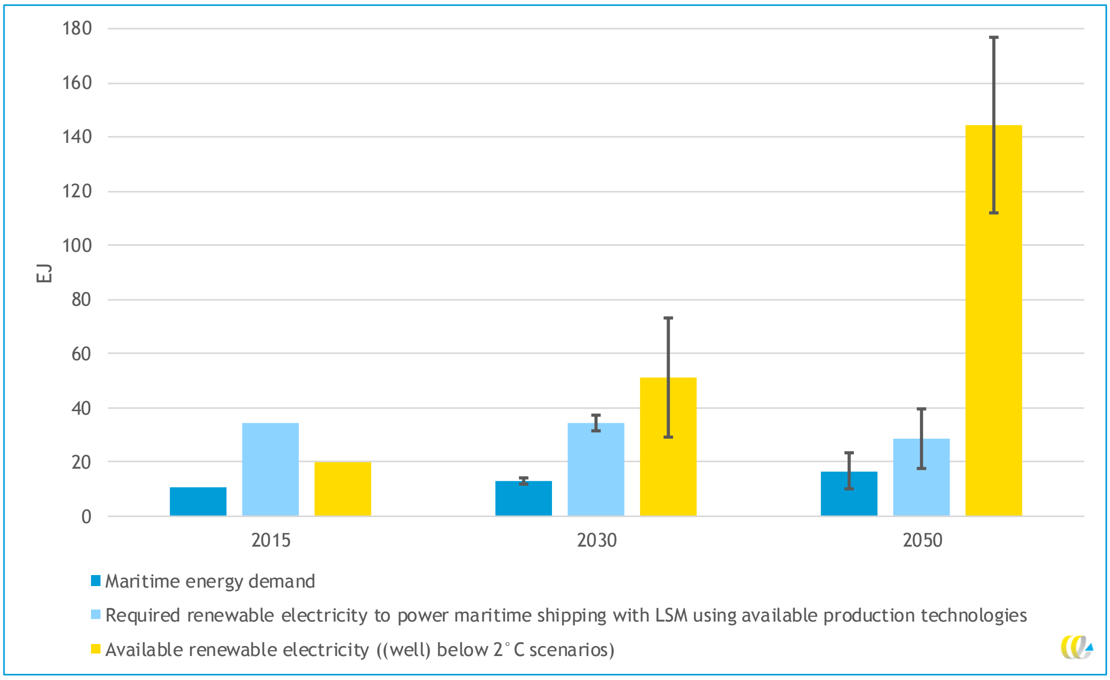
Figure 14 illustrates the information provided in Table 30, i.e. (expected) energy demand for shipping and electricity demand for the production of LSM if the marine energy demand was fully covered by LSM, and compares these with the expected global renewable electricity production. Regarding the latter '2°C scenarios' (first figure) and '(well) below 2°C scenarios' (second figure) are differentiated (see Table 23 above for the according data)

Figure 14 shows that global renewable electricity currently available would not be sufficient to produce LSM up to a level that would allow to cover the entire energy demand of the shipping sectorm — the supply of renewable electricity is still rather low and the energy demand of the production process relatively high.

If the global renewable electricity production develops according the '2°C scenarios' projections, in 2030 almost the entire global renewable electricity would have to be used to be able to produce sufficient LSM to cover the entire energy demand of the shipping sector, whereas in 2050 around 30% of the entire global renewable electricity.
If the global renewable electricity production develops according the '(well) below 2°C scenarios' projections', still a significant share of the global renewable electricity production (67%) would be required to produce sufficient LSM to cover the entire energy demand of the shipping sector, whereas in 2050 this would be 20% only.

Figure 14 — Maximum potential supply of LSM compared with maritime energy demand given a renewable electricity supply in line with a 2°C degree scenario (figure above) and in line with a well below 2°C degree scenario (figure below)





The availability of LSM is constrained by both technological and economic factors which limit the production of essential inputs. Producing LSM requires hydrogen, the production of which requires renewable electricity if it is to be carbon neutral. Whereas technologies to produce renewable electricity are on the market and can be considered mature, the current share of renewable electricity in the mix is insufficient to produce sufficient LSM to power a significant share of the fleet. The situation is projected to improve, although the investments require adequate policies.

In addition to renewable electricity, freshwater and electrolysers are needed to produce hydrogen. Freshwater can either be sourced directly or produced with desalination installations, which are mature technologies and increasingly abundant. The situation with electrolysers is different. Although mature technologies are available on the market, the current worldwide capacity is low and large increases in production capacity would be required to produce sufficient amounts of hydrogen to power a significant share of the fleet.

The other input to the production of LSM is CO_2. The technology to capture CO_2 from air is not yet commercially available, so technological developments as well as scaling needs to take place before sufficient amounts can be captured. However, while direct air capture technology is being developed, CO_2 can be captured from point sources. To the extent that these sources are of biological origin, the CO_2 can be considered to be carbon neutral. Biogenic CO_2 will however not be available at a large scale, at least in the short- and medium-run.

In sum, technologies are available on the market to produce LSM. However, the production rates are inadequate for supplying a significant share of the fleet with LSM, so considerable investments in production plants will be required for LSM to become a major fuel for shipping.

3.3 Cost analysis

The cost price of LSM as marine fuel, is determined by the costs for the production of synthetic methane, the liquefaction costs, the transportation costs as well as the costs of the bunker fuel supplier.

There is a strand of literature that has analysed the production costs of synthetic methane. The outcome of these studies together with the underlying assumptions will be presented in the following section.

3.3.1 Production costs of synthetic methane

The production costs of synthetic methane are determined by the plants' capital costs, the plant's fixed and variable operational costs as well as the costs for the inputs, i.e. the costs for electricity, CO_2, and water.

Capital and operational costs thereby depend on:
- the actual technologies used (e.g. the type of electrolyser used);
- the technologies' stage of development;
- the scale at which the technologies are available and the actual scale of the plants built;
- the configuration of the plants (the capacity of the electrolyser and the methanation plant and whether hydrogen storage is used as process buffer);
- the life-time/replacement requirements of the different components of the plants;

— the annual operating hours of the plants;
— the operation and maintenance requirements of the plants;
— whether byproducts (like heat) are used.

The costs of the inputs depend on:

— the CO_2 source and capture technology applied (DAC is most expensive and CO_2 from biogenic point source amongst the least expensive options; see Section 3.2.4) and the distance between the CO_2 source and the methanation plant;
— the renewable power source, its geographic location and the distance between the power production and the electrolyser and methanation plant; and
— the water source and the distance between the water source and the electrolyser.

A number of projects to demonstrate and test the production of renewable synthetic methane are being carried out (see (M. Thema, 2019) for a recent overview), but to our knowledge, production costs have not been published for these projects. The uncertainty of the production costs is thus still rather high. Due to this uncertainty, but also due to the different value chains analysed in the different studies, the range of the estimated production costs of renewable synthetic methane is still rather high in the literature.

Some studies have looked into the major cost factors of the production of synthetic methane/synthetic fuels. According to (Gorre, 2019), the production costs of synthetic methane highly depend on the electricity costs and the operating time of the electrolysers and the methanation plant. (Selma, et al., 2018) conclude from their literature review that most studies find that the capital costs of electrolyser as well as the stack life span and the need for stack replacement, in combination with the electricity price are the main parameters affecting the production cost of electrofuels. Revenues from byproducts as well as the scale of the electrofuels plant should also not be neglected. From their own calculations, including different sensitivity analyses, (Selma, et al., 2018) conclude that the electrolyser costs (capital costs, stack replacement, O&M and other plant investment costs) dominate the current costs of electrofuels, while in 2030 the electricity costs would dominate. According to (Frontier Economics, 2018), electricity generation costs make up a significant fraction of the total costs of synthetic methane: in 2020 they would be by far the largest cost component and in 2050 still a significant fraction of the total costs. (Frontier Economics, 2018) consider the conversion plants utilisation rates and investment costs as the second most important cost component.

In the following we will present estimations of the production costs of synthetic methane as determined in four recent studies that have analysed the costs at great length. Next to presenting the studies' estimation results, we will go into the differences of the studies thereby focussing on the major cost factors as presented above.

(Selma, et al., 2018) have reviewed 24 articles on synthetic fuels published between 2010 and February 2016 of which 12 consider the production of synthetic methane. They conclude that "[m]ethodologies and data used for assessments of electrofuel production costs vary greatly in the literature, as do the resulting cost estimates". To allow for a meaningful comparison of the production costs of different fuel options (Selma, et al., 2018) have calculated the production costs of the fuel options themselves, applying a consistent methodology and applying ranges of values to the different assumptions, based on the 24 articles they have reviewed and complemented by additional research. In their 2015 reference scenario they find production costs of synthetic methane to lie in the range between 120 and 650 EUR_{2015}/MWh and in their 2030[19] reference scenario in the range

[19] In (Selma, et al., 2018), the year 2030 is used as a proxy for a time in the future when certain technological improvements and volume of production are achieved.

between 100 and 290 EUR_{2015}/MWh. Their assumptions with regards to the identified crucial cost factors are in the reference scenario:
- Plant scale: 5 MW in 2015 and 50 MW in 2030.
- Type of electrolyser: Alkaline electrolyser in 2015 and 2030.
- CAPEX electrolyser: in 2015: 600-2,600 EUR/kW_e in 2030: 400-900 EUR/kW_e.
- Stack life span: in 2015: 60,000-90,000 hours, in 2030: 90,000-100,000 hours.
- Stack replacement costs: 50% of investment costs.
- Capacity utilization: 80%.
- Price of electricity for electrolysis: 50 EUR_{2015}/MWh in 2015 and 2030.

(Gorre, 2019) estimate the production costs for synthetic methane considering a plant of 10 MW_e for different scenarios (Continuous operation, Operating Strategy I/II), accounting for different full load/hot standby hours of the electrolyser and the methanation plant as well as different electricity prices and sizes of hydrogen storage tanks used.

Note that hydrogen storage tanks might be used for two reasons (Gorre, 2019):
1. The minimum load and the possible load change rates of methanation are typically not the same as for electrolysis, at least if significant quality losses in the conversion are not accepted. Electrolysers can switch from cold standby to operation mode in seconds/minutes whereas methanation needs a few hours to warm up.
2. The hydrogen processing rate of methanation and the hydrogen production rate of the electrolysers might need alignment.

In the Operating Strategy I-Scenario, only a small hydrogen storage tank is used and electrolyser and methanation plant have the same amount of annual full load hours (FLH) and hot standby hours (HSH). Six different combinations of FLH and HFH and five alternative electricity prices are thereby differentiated.

In the Operating Strategy II-Scenario, larger hydrogen storage tank are used, allowing the methanation plant to be operated at a high number of annual FLH. For the electrolyser plant, the same six different combinations of FLH and HFH as considered in the Operating Strategy I-Scenario are assumed and three alternative electricity prices are differentiated.

If the plants are operated continuously (8,750 annual FLH), no hydrogen storages is needed. For this scenario, (Gorre, 2019) give the 2030 cost estimation only, working with a range of 0-100 EUR/MWh for the electricity price.

Table 31 gives an overview of the resulting ranges of synthetic methane production costs.

Table 31 — Estimation ranges of production costs of synthetic methane

Scenario [EUR_{2018}/MWh_{SNG}]	**2030**	**2050**
Continuous operation	33-204	
Operating Strategy I-Scenario	50-313	24-170
Operating Strategy II-Scenario	42-226	20-138

Source: (Gorre, 2019).

Regarding the two other scenarios (Operating Strategy I/II-Scenario), the low end of the ranges reflect subscenarios with high annual full load hours (6,000 full load hours for electrolysers) and very low electricity prices (0 EUR/MWh) and the high end of the ranges subscenarios with low annual full load hours (1,000 hours for electrolysers) and higher electricity prices (25 EUR/MWh).

For 2050, the production costs are estimated to be lower for each scenario mainly due to the assumption that the costs of the main components (electrolyser, methanation reactor and CO_2 separation units) will decline due to technological learning.
Since 6,000 full load hours for electrolysers and an electricity price of 0 EUR/MWh might not be feasible (and especially the combination thereof), we also give the cost ranges for maximally 4,000 annual full load hours and an electricity price of 10/25 EUR/MWh as derived by (Gorre, 2019):

Table 32 — Estimation ranges of production costs of synthetic methane (10 MW_e plant, (sub)scenarios with maximally 4,000 annual full load hours and two alternative electricity prices (10/25 EUR/MWh))

Scenario [$EUR_{2018}/MWh_{synthetic\ methane}$]	2030	2050
Operating Strategy I-Scenario	88-313	53-170
Operating Strategy II-Scenario	72-226	43-138

Source: (Gorre, 2019).

With regards to the crucial assumptions as established above, (Gorre, 2019) assume:
- Plant scale: detailed scenario for 10 MW_e plant, but CAPEX also specified for 1 and 50 MW_e plants.
- Type of electrolyser: not specified.
- CAPEX electrolyser: 2017: 1180 EUR_{2017}/kW_e; 2030: 415-665 EUR_{2017}/kW_e (50-1 MW plant); 2050: 220-350 EUR_{2017}/kW_e (50-1 MW plant).
- Stack life span: 10 years.
- Stack replacement costs: not specifically reported for the stack.
- Capacity utilization scenarios:
  - Operation Strategy I: electrolysers and methanation plant are operated in the same way: 1,000/2,000/4,000/6,000 full load hours with the remaining hours (to the maximum annual operating hours of 8,760) in hot standby;
  - Operation Strategy II: electrolyser are operated just as under Operation Strategy I and methanation plant is operated almost continuously (8,500 full load hours and 260 hours in hot standby).
- Price of electricity for electrolysis: different scenarios: 0/1/5/10/25 EUR_{2017}/MWh.

(Frontier Economics, 2018) have estimated the 2030 and 2050 costs for producing different synthetic fuels for four main scenarios. In the first scenario, synthetic fuel is produced in Germany using North and Baltic Sea offshore wind power, in the second and third scenario it is produced in North Africa and Middle East respectively, using PV/wind systems, and in the fourth scenario, it is produced in Iceland using geothermal/hydropower. Their model, which is available online[20], allows to calculate the production costs of synthetic methane for each of the four scenarios and for alternative inputs, like direct air capture (TSA)/CCU (cement industry), low/base/high cost reduction in the future, different load hours per year, etc. Table 33 gives the resulting cost ranges (reflecting the different scenarios) for direct air capture of CO_2 and carbon capture at cement plants assuming 8,000 full load hours per year from geothermal/hydropower in Iceland and 4,000 full load hours from PV/wind systems in the per year — annual full load hours estimated to be realistic by (Frontier Economics, 2018).

[20] See Agora PtG/PtL Calculator

Table 33 — Production cost estimates (excluding transportation costs, grid tariffs, levies and taxes) of synthetic methane for different CO_2 sources

Reference scenario [$EUR_{2017}/MWh_{methane}$]	2030	2050
Direct air capture	88-196	76-137
Carbon capture cement industry	70-180	60-122

Source: (Frontier Economics, 2018).

This means production costs are estimated to fall in 2030 in a range of around 70 to 195 $EUR/MWh_{methane}$ and in 2050 in a range of around 60 to 140 $EUR/MWh_{methane}$, depending on the CO_2 source.

With regards to the crucial assumptions as established above, (Frontier Economics, 2018) assume:

— Plant scale: not specified; to achieve the cost reductions projected in the study, cumulative global electrolysis capacity must reach an order of magnitude of 100 gigawatts in 2050.
— Type of electrolyser: either low temperature (alkaline, PEM) or high temperature electrolysis (SOEC) can be selected in model.
— CAPEX electrolyser:
  - low temperature electrolysis: 2030: 440-710 EUR_{2017}/kW_e, 2050: 200-600 EUR_{2017}/kW_e;
  - high-temperature electrolysis: 2030: 675-910 EUR_{2017}/kW_e, 2050: 400-800 EUR_{2017}/kW_e.
— Stack life span: life time of electrolyser is assumed to be 25 years, whether stacks are assumed to be replaced in between is not clear.
— Stack replacement costs: not specified.
— Capacity utilization scenarios: can be varied in the model; 4,000 annual full load hours for PV/wind and 8,000 annual full load hours for geothermal/hydropower are assessed to be realistic for the regions analysed.
— Price of electricity for electrolysis: specified in $cent/kWh_{H2}$ only.

(Navigant, 2019) estimate the 2050 production costs of synthetic methane to amount to EUR_{2018}74/MWh. The estimation is thereby based on one specific scenario. In this scenario, the following values have been used for the above established crucial assumptions:

— Plant scale: 5 MW.
— Type of electrolyser: PEM.
— CAPEX electrolyser: in 2050: EUR420/kW.
— Stack life span: 2018: 20,000-60,000 hours; 2050: not specified.
— Stack replacement costs: OPEX (including replacement, maintenance and labour costs): 3% of CAPEX per annum.
— Capacity utilization:
  - electrolyser: 2,000 full load hours a year;
  - methanation plant: 4,000 full load hours a year; onsite hydrogen storage is assumed
— Price of electricity for electrolysis: 0 EUR/MWh.

Conclusions

Our literature review confirms the findings of (Selma, et al., 2018) in the sense that we also find varying estimates for the production costs of synthetic methane: for 2030 between around 23-110 USD_{2019}/MMBtu for 2050 and of around 15-60 USD_{2019}/MMBtu.

These broad cost differences can be attributed to the different assumptions regarding the size of the plant analysed, the operating hours of the plant and the electricity costs for electrolysis. Optimization of the constellation and operation of the different parts of the plants can also have a significant impact on the production costs. Using excess renewable electricity can be expected to lead to relative low electricity costs for electrolysis (some studies even assume that excess electricity is free), but will probably only allow for a small number of operating hours per year and might require hydrogen storage or the methanation plant to be on standby.

4 Comparison of costs

4.1 Introduction

Next to LSM and LBM, there are several other types of zero/low fossil carbon bunker fuels under discussion. Ship owners/operator will select a specific option, depending on the availability and the according total cost of ownership. An analysis of the total cost of ownership for different ship types/sizes and operational patterns, depending on the fuel used and the according propulsion system is out of the scope of this study. What we do in this chapter is to rather compare, first, the expected bunker cost price of LBM and LSM with the expected bunker cost price of two fossil bunker fuels (LNG and VLSFO) and, second, we compare the costs for LBM, LSM, liquid hydrogen and ammonia excluding transportation and bunkering costs — the former being highly dependent on the production location and the latter still being very uncertain for hydrogen and ammonia.

Since data availability for 2050 is rather poor, the comparison will focus on 2030.
A qualitative outlook will be given for the period between 2030 and 2050.

4.2 Production costs of synthetic and biomethane

We have conducted a literature review to determine the cost price of synthetic and biomethane at plant (see Section 2.3.1 and Section 3.3.1):

For biomethane for the current situation, the cost price from anaerobic digestion is estimated to lie in the range of around 20 to 50 USD/MMBtu and to be lower than for gasification (around 25-65 USD/MMBtu). For both processes, production costs are expected to be lower in 2050, with the costs for gasification (13 USD/MMBtu) then being lower than for anaerobic digestion (15-21 USD/MMBtu). However, only limited research has been carried out for the 2050 situation.

The estimations of the cost price of synthetic methane vary highly:
around 23-110 USD/MMBtu for 2030 and around 15-60 USD/MMBtu for 2050.

4.3 Production costs of hydrogen

Hydrogen produced by means of water electrolysis is one of the renewable fuel options under discussion for maritime shipping. Hydrogen can be used in fuel cells. In principle, it can also be used in internal combustion engines, but a marine internal combustion engine has not been developed yet and, to our knowledge, is currently not under development.

Hydrogen has the advantage that it does require no/very little pre-treatment if used in fuel cells and the production costs of hydrogen can be expected to be lower than the production costs of synthetic methane since the production of hydrogen is part of the production of synthetic methane.

But hydrogen has also got some disadvantages. It has a low volumetric energy density and a very low boiling point (-253°C), requiring energy intensive liquefaction and cryogenic storage for use and transport by ships. It is also extremely flammable and may explode if heated.

Several estimations of the production costs of renewable hydrogen can be found in the literature. Table 40 in Annex D.2 provides an overview. Most estimations are related to 2030, but some studies also provide estimations for 2050. Estimations for production costs of renewable hydrogen of between 10 and 63 USD/MMBtu for 2030 and between 5 and 25 USD/MMBtu for 2050 can be found in the literature.

4.4 Production costs of ammonia

Next to hydrogen, ammonia is discussed as a potential renewable fuel for maritime shipping. Ammonia can potentially be use in internal combustion engines and, as a hydrogen carrier, also in fuel cells. A marine internal combustion engine for ammonia is not available yet, but the development time is estimated to amount to 2 to 3 years.

Ammonia is an important industrial product, the majority being used to produce fertilizer. The Haber-Bosch process for the production of ammonia is a well-established process. Atmospheric nitrogen and hydrogen, currently obtained from natural gas, are the main inputs for this process. In order to produce renewable, carbon-free ammonia, the hydrogen used as an input for the process would, just as for LSM, need to be produced by means of water electrolysis. In contrast to the production of LSM, ammonia production does not require CO_2 capturing, but capturing of nitrogen. The advantage is that the concentration of nitrogen in the atmosphere is relatively high and that the nitrogen capturing process is well established.

Alternative ammonia synthesis technologies have been explored, like solid state ammonia synthesis and biochemical solutions, but according to Cerulogy (2017) these technologies will not be available at commercial scale the next 10 years and data availability for these technologies is very poor.

When compared to LSM/LBM and hydrogen, ammonia has the advantage that its boiling point is relatively high (around -33.40°C) which means that it can become liquid at relative low pressure and does not require cryogenic storage. Liquefaction, storage and transportation costs are therefore significantly lower. This is also why for the transport of hydrogen its conversion to ammonia is discussed in the literature. In addition, it is considered a flammable gas rather than an extremely flammable gas like methane. The latter, together with a high auto ignition temperature, makes handling of ammonia relatively safe, but is at the same time a challenge for the combustion process.

A major disadvantage of ammonia is however its toxicity: According to the harmonised classification and labelling approved by the European Union, it causes severe skin burns and eye damage, is toxic if inhaled and is also very toxic to aquatic life (ECHA, 2020). In addition, ammonia is corrosive to copper, copper alloys, nickel and plastics (Brohi, 2014).

Different estimations of the production costs of renewable ammonia can be found in the literature. Table 39 in Annex D.1 provides an according overview. Most of these studies estimate the expected current costs and/or the expected costs in 2025/2030 and only one study that we are aware of estimates the expected costs in 2050. The major differences between the production cost estimations seem to be the price of the renewable electricity assumed for the production of hydrogen and the assumed electrolyser load factors. The former differs, depending on the assumed production location, the renewable energy source and the expected future efficiency improvement of the according conversion technology.

From the literature review we conclude that, the production cost of renewable ammonia is estimated to lie in a range of 17 to 105 USD/MMBtu for 2025/2030 and one study estimates the costs to be around 10 USD/MMBtu in 2050.

Given the fact, that the production of renewable ammonia uses renewable hydrogen as input, production costs of renewable ammonia should inherently be higher than the production costs of renewable hydrogen, at least, given the same hydrogen production process and costs. Comparing the cost estimations for ammonia and hydrogen, this is only reflected in the lower end of the cost range. This means that different assumptions have been made with regards to hydrogen production in the estimations of the hydrogen and the ammonia production costs, probably with regards to the production location and the according electricity price.

4.5 Liquefaction, transport and bunker infrastructure costs of the alternative fuels

4.5.1 LBM and LSM

Liquefaction, transportation and bunker infrastructure costs can be expected to be the same for (L)BM and (L)SM as well as (L)NG at least if the production location is assumed to be the same.

Liquefaction costs

Methane has a boiling point of -162°C which means that it has to be cooled down to -162°C to become liquid. Liquefaction of methane is therefore an energy intensive process. Based on the performance evaluation of real life liquefaction terminals, the energy demand of the process is assessed to be up to 10% of the supplied natural gas (Pospisil & Charvat, 2019).

For the liquefaction of natural gas, DNV GL (2019b) finds 3 to 5 USD/MMBtu to be an adequate cost range estimate for today (end of 2019) and OIES and University of Oxford (2018) give liquefaction costs for different plants, ranging from 2.5 to 4.5 USD/MMBtu.
For the following analysis we assume the 2030 liquefaction costs to be at the lower range of the current costs, i.e. to be 3 USD/MMBtu.

Transport costs

The transport costs considered in this study are the costs for transporting the methane to the port, for fuelling of ships.

Independent of the fuel transported, transport costs will differ highly depending on the location of the production and the location of the port where the bunker fuel will be sold. There are two main options for the transport of the methane to a port:
1. Transport by pipeline, in gaseous form. The methane will in this case be liquefied in the harbour and not at the plant:
   a The gaseous methane is injected into the natural gas grid.
   b An existing gas pipeline is prepared for use as dedicated pipeline.
   c A new pipeline is built.
2. Transport by truck and/or ship, in liquid form. The methane will in these cases be liquefied at the location of production.

Transport by pipeline – injection into NG grid

When synthetic/biomethane is injected into the natural gas grid, this results in a mixture with natural gas. Liquefaction systems in ports could then administratively produce LSM/LBM, if they bought according certificates from the producer. In case of a dedicated synthetic/biomethane pipeline, synthetic/biomethane is physically delivered to the port, and the bunker fuel supplier will physically receive 100% synthetic/biomethane.

Transport by pipeline – use of existing gas pipeline

Not all biomethane production locations will be close enough to the harbour to make the construction of a new pipeline a cost-effective option. However, in some cases it may be possible to transform a former natural gas pipeline (or other pipeline) into a dedicated biomethane pipeline. This will be much cheaper than building a new pipeline. Biomethane has the same composition as natural gas, so the cost of preparing a natural gas pipeline is limited to the cost of executing the isolation of the pipeline from the natural gas grid. Compared to option 1a (injection into the natural gas grid), the pipeline preparation/ transformation cost is added to the biomethane production cost.

Transport by pipeline – realisation of new pipeline

Building a dedicated biomethane pipeline for a single biomethane plant will be expensive, but if multiple biomethane plants can make use of the same (backbone) pipeline to the harbour, the investment costs can be shared. The pipeline diameter will be larger in these cases, which will reduce the material cost per kilometre. Baldino et al. (2018) indicate, based on data from the New York State Energy R&D Authority, that the pipeline CAPEX of a biogas pipeline for a single farm are 100,000-200,000 EUR per kilometre. Trinomics et al. (2019) show higher values based on a literature review: a CAPEX of transmission pipelines of400,000-1,500,000 EUR/km and a CAPEX of distribution pipelines of 300,000-900,000 EUR/km, with higher values representing larger pipeline diameters.

Under all options of pipeline transport, there are *injection and connection costs* associated with the connection of the plant to the pipeline and feed-in of the methane. These include the investment in injection capacity and operational expenses. Also, in all options, the OPEX includes the costs of compression and measurement. Other costs, such as conditioning of the methane to the gas quality in the grid and odorisation, are only applicable when the biomethane is injected into the natural gas grid.

Economies of scale play a large role in the CAPEX of the injection system. As a result, methane injection costs may decrease from 0.46-0.69 USD/m^3 at 100 m^3 gas/hour to 0.05-0.1 USD/m^3 at 2,000 m^3 gas/hour according to IRENA (2018b).These costs include conditioning and odorisation costs, so for dedicated pipelines the values will be lower. The difference between the minimum and maximum values mainly reflects the different costs of biomethane compression, as injection into low-pressure grids is cheaper than injection into high-pressure grids. The share of CAPEX in total grid injection costs drops from more than 50% to less than 30% (IRENA, 2018b).

Navigant (2019) estimates grid injection cost of biomethane at 3.3 USD/MWh and connection costs at 2.2 USD/MWh (assuming 1 km steel pipes).

Transport by truck

In cases where grid injection and pipeline modification are undesirable and/or not possible (for example, due to the absence of a gas grid) and where the distance between the biomethane production location and the port is too large (in the order of more than 5-10 kilometres for small pipelines and more than 30-50 km for medium pipelines, according to Vasilevich et al. (2016) transport of liquid methane by truck is the cheapest solution. The cost of LNG transport by truck is estimated at 3.4-6.8 USD/MWh by Tractebel Engineering (2015). Larger quantities and shorter transport distances lead to lower transport costs. IRENA (2018b) reports costs of biomethane as a compressed gas (in high-pressure steel cylinders on trucks) of 0.17-0.22 USD/m^3.

Transport by ship

If liquefied at the production site, liquefied methane can also be transported by ship. The according liquefied methane shipping costs are difficult to estimate, given the time charter rates (USD/day per vessel) for LNG vessels have been very volatile in the past, as illustrated in Figure 15.

Figure 15 — Historical LNG time charter rates

Source: Clarksons in (FT, 2018).

Bunkering costs

LBM and LSM have the advantage that they can make use of LNG bunkering infrastructure which is technically mature and commercially available.

Just as for LNG, there are in principle three different options for the bunkering of LBM and LSM (website World Port Sustainability Program, 2019):
- Currently, **truck-to-ship bunkering** is used most often, because of limited demand from ships, a lack of infrastructure and relatively low investment costs. A disadvantage of this bunkering method is the limited capacity of trucks of approximately 40-80 m^3. Therefore, this method is not suitable for larger ships.
- **Ship-to-ship bunkering** can take place at various locations (even at sea) and is a flexible bunkering method, but bunker vessels are costly and can hardly be used for other commercial operations. It is expected that ship-to-ship bunkering becomes the main bunkering method in the future, when a large fleet of LNG/LBM/LSM-fuelled ships has developed.
- A third bunkering method is **shore-to ship bunkering**, in which case the liquefied methane is delivered to the ship directly from a tank, station, or terminal. This method is suitable for ports with a stable bunkering demand, but is less flexible and it takes more effort for ships to get to the location.

For each of these methods it holds that the availability is still limited worldwide.
For ship-to-ship bunkering — the conventional bunkering method in maritime shipping — LNG bunkering vessels are required. Currently (November 2019), eight LNG bunkering vessels are in service worldwide, excluding LNG bunkering barges, and eight LNG bunkering vessels are on order.

CE Delft and TNO (2015) have calculated the costs for LNG supply in different EU ports, considering the value chain from the import terminal on. Alternative forms of LNG transport between import terminal and port and alternative bunkering methods as well as local specific factors (like distances and LNG sold per year), result in a cost range of 1 to 4 USD/MMBtu. If LNG supply in ports is scaled-up in the future, these costs can be expected to decline.

4.5.2 Hydrogen

Hydrogen has a much higher energy density per unit of mass if compared to methane, however it has a lower volumetric density which means that hydrogen requires more storage space per unit of energy than methane. Hydrogen, just as methane, needs to be liquefied for the use on board ships. With a boiling point lower than methane (-253°C vs -161°C) liquefaction of hydrogen is more energy intensive than the liquefaction of methane. According to IRENA (2019d), the amount of electricity that is required to liquefy hydrogen, would currently lead to losses of 20 to 45% of the hydrogen energy content. According to IEA (2019d) hydrogen liquefaction costs amount to around 1 USD/kg H_2 (or 9 USD/MMBtu) and is the value we apply in the cost comparison. The value falls in the range of the range of the hydrogen liquefaction costs as given by (Lloyd's Register; UMAS, 2019): 0.5 and 1.1 €/kg H_2 or 5-11 USD/MMBtu.

High storage and liquefaction costs makes transport of hydrogen by ships costly. This is why for transportation purposes, conversion of hydrogen into other energy carriers, for example ammonia, is an option discussed in the literature. According to IEA (2019d) “for distances below 1,500 km, transporting hydrogen as a gas by pipeline is likely to be the cheapest delivery option; above 1,500 km, shipping hydrogen as ammonia or an LOHC [liquid organic hydrogen carrier] is likely to be more cost-effective.” When choosing a production location for renewable hydrogen, it will thus be important to find a balance between electricity costs and transport distance.

Bunkering infrastructure for hydrogen is still under development: for land-based transportation, there are refuelling stations for liquid hydrogen, but for maritime shipping the infrastructure is technologically not mature yet (NCE Maritime Cleantech, 2019). Different options are being discussed in this context and feasibility studies are carried out (NCE Maritime Cleantech, 2019).

4.5.3 Ammonia

When compared to LSM/LBM, ammonia has the advantage that its boiling point is relatively high (around -33.40°C) which means that it can become liquid at relative low pressure and/or under relatively mild conditions. Liquefaction, storage and transport costs are therefore lower than for hydrogen and LNG/LSM/LBM. The energy required for the liquefaction of ammonia is expected to be relatively low — less than 0.1 percentage by mass of ammonia — and can therefore be considered negligible.

Regarding the transportation costs of ammonia, not much information can be found in the literature. According to (IEA, 2017c) ammonia could be shipped at a cost of 40 USD/t NH_3 to 60 USD/t NH_3 (which corresponds to 2.3-3.4 USD/MMBtu) depending on distance and vessel size. CE Delft (2018b) assumes the transportation of ammonia from Morocco to the Netherlands to cost 0.16 EUR/kg H_2 (which corresponds to around 1.5 USD/MMBtu).

Bunkering infrastructure for ammonia has not been developed yet at all. Since ammonia is shipped as cargo, it can be expected that the development of the infrastructure will be able to build on the experience from ammonia handling, but there are no estimations of the infrastructure costs in the literature available yet.

4.6 Fossil bunker fuels

4.6.1 Fossil bunker fuel prices

LNG

LNG bunker prices are only starting to be reported and LNG bunker price projections are also scarce. Nevertheless, to come to an estimation of the 2030 LNG bunker price, the following approach has been applied:
1. There are regional differences between natural gas prices. Currently, the natural gas price in the US is lower than the natural gas price in Europe; in Japan, where natural gas is imported as LNG, the natural gas price is highest. According to the World Bank (2019) it can be expected that in 2030, the US and the Japanese natural gas price will still represent the lower and higher end of the natural gas price range.
2. Based on the World Bank Commodities Price Forecast (World Bank, 2019) for US natural gas and for LNG in Japan in 2030, we estimate an according 2030 LNG bunker fuel price range.

According to the World Bank Commodities Price Forecast (World Bank, 2019), the US natural gas price is expected to amount to 4 USD/MMBtu and the Japanese LNG price to 8.5 USD/MMBtu. Applying the methodology as presented in SEA\LNG (2019), i.e. adding liquefaction costs and specific mark-ups to the US natural gas price, a 2030 LNG bunkering price of around 11 USD/MMBtu is estimated as the lower range. Assuming that the LNG logistics and bunkering costs in Japan are comparable to the costs in the US (3.08 USD/MMBtu as specified in SEA\LNG (SEA\LNG, 2019)), we estimate a 2030 LNG bunkering price of around 12 USD/MMBtu as the higher range.

As a result we work with a 2030 LNG bunker price range of 11-12 USD/MMBtu.

Very Low Sulphur Fuel Oil (VLSFO)

Since beginning of 2020, maritime ships are obliged to use fuel with a maximum sulphur content of 0.5% m/m if sailing outside Emission Control Areas. Ships also use exhaust gas cleaning systems to comply with the regulation, but so far, the majority of the ships use VLSFO to comply the sulphur regulation; a small, but increasing share of ships use LNG.

Since there are very little historical data on VLSFO prices available, no valid correlations with for example the crude oil price can be established, making an estimation of the 2030 VLSFO price even more difficult than the estimation of the 2030 LNG price. To nevertheless come to an estimation of the 2030 VLSFO bunker price, the following approach has been applied:

1. We have determined a range of the average VLSFO price for the period 1 November 2019–27 January 2020, with the average price in Rotterdam representing the lower and the average price in Singapore the higher end of the range. Publicly available data from Ship & Bunker (2019) have been used to this end. This resulted in a range of 531–621 USD/mt[21] which is equivalent to 14-15.7 USD/MMBtu.
2. We have compared the average crude oil price for the same period and compared it with the 2030 World Bank crude oil price estimation (70 USD/barrel) to establish the potential maximum increase of the VLSFO price until 2030. This resulted in a potential maximum increase of around 8%.
3. Applying this maximum increase to the bunker price range as established under point 1, this results in a 2030 VLSFO bunker price range of around 15-17 USD/MMBtu.

4.6.2 Carbon mark-up

In its Initial Strategy on Reduction of GHG emissions from ships (MEPC.304(72)), the IMO has agreed on a level of ambition and on the development of policy measures to meet this level of ambition. However, no specific measures and thus also no specific stringency levels of have been agreed upon yet. This makes it difficult to estimate the carbon price that will become effective for the maritime shipping sector.

The IMO aims to phase out GHG emissions from international shipping as soon as possible in this century and perceives its 2050 goal (50% by 2050 compared to 2008) as a point on a pathway of CO_2 emissions reduction consistent with the Paris Agreement temperature goals.

We therefore decided to use a carbon prices in line with estimations of the global average carbon prices required to implement the Paris Agreement temperature goals.

There are different estimations of average regional, but only very few estimations of global average carbon prices required to implement the Paris Agreement temperature goals.

[21] Please be aware that the VLSFO featured a price spike beginning of January 2020 which in retrospective could turn out to be an outlier, but at this point in time this is still unclear.

The High-Level Commission on Carbon Prices (2017) concludes that the carbon-price level consistent with achieving the Paris temperature target (increase of well below 2°C above pre-industrial levels) is at least 40–80 USD/t CO_2 by 2020 and 50–100 USD/t CO_2 by 2030, provided a supportive policy environment is in place.

For the cost price comparison of the different bunker fuels we therefore stick to the 2030 carbon price range of 50–100 USD/t CO_2. This translates into the following carbon price mark-up per MMBtu:
- LNG: 3.0-6.1 USD/MMBtu;
- VLSFO: 4.0–8.0 USD/MMBtu.

For the conversion of the carbon price mark-up, the following assumptions have been made, based on the EEDI guidelines (MEPC 73/19/Add.1, Annex 5):
- CO_2 emission factors: 2.75 kg CO_2/kg LNG, 3.114 kg CO_2/kg HFO, and 3.206 CO_2/kg MGO;
- Lower heating values of the fuels: 48 MJ/kg LNG, 40.2 MJ/kg HFO, and 42.7 MJ/kg MGO;
- VLSFO is assumed to be a blend consisting of 20% HFO and 80% MGO.

4.6.3 Fossil bunker fuels including carbon mark-up

Combining the 2030 price estimations for LNG and VLSFO excluding a carbon price (see Section 4.6.1) and the carbon mark-up as derived under 4.6.2, we estimate the 2030 bunker prices of LNG and VLSFO including a carbon price of 50–100 USD/tCO_2 to be around:
- 14-18 USD/MMBtu for LNG; and
- 19-25 USD/MMBtu for VLSFO.

4.7 Cost comparison

Data availability allows for a limited comparison of the different bunker fuels only.

In the following we will present two different cost comparisons:
1. First, we compare the expected bunker prices for the fossil bunker fuels (LNG & VLSFO) with the expected bunker costs for LBM and LSM. For LBM and LSM we thereby assume the same liquefaction, distribution and bunkering costs as for NG. No long-distance transportation costs for LBM and LSM since these highly depend on the production location. This implicitly implies that LBM and LSM are produced locally.
2. Second, we compare the costs for LBM, LSM, liquid hydrogen and ammonia excluding transportation and bunkering costs — the former being highly dependent on the production location and the latter still being very uncertain for hydrogen and ammonia.

As already indicated, data availability for 2050 is rather poor, which is why the comparison will focus on 2030. For biomethane data for 2030 is not available: most cost data is related to current costs and only a few studies have looked into 2050 costs. The 2030 cost estimates for biomethane used in the following comparisons have therefore been derived by a rough interpolation of the data available.

4.7.1 Comparison of fossil and renewable fuels

Table 34 presents estimations for the 2030 bunker prices of VLSFO, fossil LNG, LBM and LSM. The bunker prices for VLSFO and fossil LNG include a carbon mark-up. For the estimation of the bunker prices of fossil LNG, LBM and LSM, the same liquefaction costs (3 USD/MMBtu) and the same LNG logistics and bunker costs (3 USD/MMBtu) and the same price mark-ups as presented in SEA\LNG (2019) have been applied.

Table 34 — Estimated 2030 per energy unit bunker prices for LBM and LSM compared with existing bunker fuels

Bunker fuel	Estimated 2030 bunker price (USD/MMBtu)
VLSFO	19-25 (including carbon mark-up)
Fossil LNG	14-18 (including carbon mark-up)
LBM	29-63
LSM	35-145

Per energy unit, fossil LNG is forecast to be the cheapest and LSM the most expensive bunker fuel in 2030. Fossil LNG is estimated to be between 1 to 11 USD/MMBtu cheaper than VLSFO. LSM can only be cheaper than LBM, if cheap renewable electricity is available and high electrolyser load factors can be achieved.

From these estimations it can be concluded that a carbon mark-up of between 50–100 USD/t CO_2 will not be sufficient to incentivize a switch from fossil LNG to LBM or LSM in 2030.

Assuming that the bunker price of fossil LNG is constant after 2030 and that the lower range of the 2030 production costs for LBM is relevant in the long-run, then a carbon mark-up of around 280-300 USD/t CO_2 would be required for LBM to become as expensive as fossil LNG. According to the IPCC (2018) a 2050 carbon price of between 300 and 400 USD/t CO_2 would be consistent with a well below 2°C mitigation pathway.

4.7.2 Comparison of alternative renewable fuels

Comparing the 2030 per energy unit costs of LBM, LSM, liquid hydrogen and liquid ammonia, excluding transportation and bunkering costs (Table 35), we find that
- The cost price range for LSM and liquid ammonia are rather broad, probably reflecting the relative high uncertainty as well as a broad range of assumptions regarding the electricity prices.
- The variation of the cost prices is lower at the lower range of the estimates.
- In an optimistic scenario (lower range of the cost estimates from the literature review),
  - Plant gate costs are broadly comparable for LBM, liquid ammonia and liquid hydrogen;
  - At plant gate costs of liquid ammonia are expected to be lowest, followed by the liquid hydrogen and LBM with LSM featuring the highest costs. Significantly lower liquefaction costs for ammonia can explain the cost differential between liquid ammonia and liquid hydrogen, but the presumed optimistic electricity price might also vary between the estimates.
- In a pessimistic scenario (higher range of cost estimates), at plant gate costs of LBM are expected to be lowest, followed by liquid hydrogen; costs for both, liquid ammonia and LSM are relatively high and highest for LSM.

Table 35 — 2030 plant gate cost price estimates for different renewable bunker fuels

	Cost price at plant gate (USD/MMBtu)
LBM	21-48
LSM	26-113
Liquid hydrogen	19-72
Liquid ammonia	17-105

The optimistic cost estimates for liquid hydrogen, liquid ammonia and LSM can probably only be achieved if the production location has favourable conditions for renewable electricity. This may require the transportation of the fuels over longer distances, depending on the locations of the bunker ports.

If transported by ship, transportation costs can be expected to be lower for liquid ammonia compared to liquid hydrogen and LSM and indeed, LBM: due to its relatively high boiling point it can become liquid at relative low pressure and/or under relatively mild conditions. Liquefaction, storage and transport costs are therefore lower than for hydrogen and LSM/LBM; for liquid hydrogen these costs can be expected to be higher than for LSM/LBM.

Since the production of LBM does not rely on the availability of cheap renewable electricity, this might allow for local production in the vicinity of major ports and could save out costs for the transport of the bunker fuel. Local production of LBM might require transport of biomass. These transport costs can be expected to be relatively low, at least if the biomass can be transported/is available in bulk.

Since the costs of the bunker infrastructure for hydrogen and ammonia are still very uncertain, the impact of these costs on the bunker fuel prices are difficult to assess at present. However, since the bunkering infrastructure of LBM and LSM are technically mature whereas the bunkering infrastructure for hydrogen and ammonia is technically still immature, the bunker price cost mark-up for the bunkering of hydrogen and ammonia can be expected to be higher than for LSM and LBM, at least in the short- and medium-run.

5 Discussion of availability for and demand of shipping sector

The analysis of the availability of LBM (see Chapter 2) has focussed on the maximum conceivable supply of LBM and the analysis of the availability of LSM (see Chapter 3) on the renewable electricity required to supply the entire shipping sector with LSM.

It would however be unrealistic to assume that these volumes of LBM/LSM would actually all become available to the shipping sector. Other sectors might switch from natural gas to LSM or LBM too and the supply of LBM/LSM could be significantly lower, since the supply of the fuels also depends on suppliers' potential profit which in turn depends on the cost price of the fuels, the consumers' willingness to pay for the fuels and the potential volume of the demand.

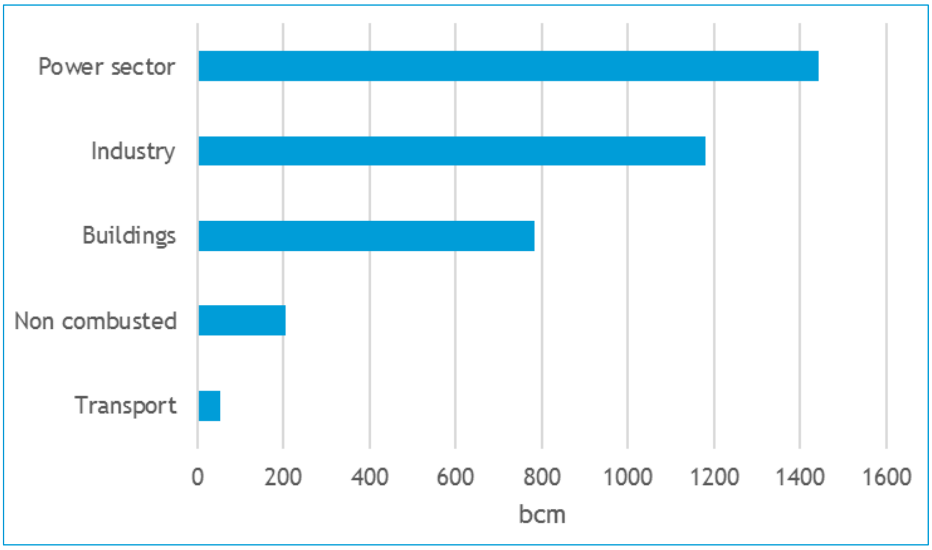
Biomass that can be used for the production of LBM could therefore be used in an alternative way, i.e. either used directly or for the production of other gaseous or liquid biofuels. And hydrogen and renewable electricity used for the production of LSM could also be used in an alternative way, i.e. either used directly or for the production of other synthetic gaseous or liquid fuels.

There are some feedstocks for which digestion and thus the production of biomethane is one of the obvious choices: feedstocks with a high water content and a low sugar, oil or starch content. But the majority of biomass feedstocks can be converted with different technologies to produce different gaseous or liquid biofuels and other bio-based products.

Obvious potential buyer of LBM and LSM are sectors that, at the outset of the energy transition, are using fossil (L)NG. By switching to LSM/LBM these sectors would avoid extra costs for system adjustments and additional indirect costs for new supply infrastructure.

As Figure 16 shows, natural gas is currently mainly used in the power sector and for (process) heating in the industry and in the built environment. In different industrial sectors natural gas is also used as feedstock to produce hydrogen and chemicals. To a relatively small extent, natural gas is used in the transport sector.

Figure 16 — 2017 global gas consumption by sector



Source: BP Energy Outlook 2019.

For each of these sectors, we will analyse whether the current demand for (L)NG will transform in demand for LSM or LBM in a decarbonized future, or that other fuels or energy sources are more obvious candidates to replace (L)NG. Figure 17 illustrates this analysis.

The **power sector** currently uses (L)NG, amongst others, to produce electricity. Since LSM requires the use of renewable electricity, and since there are energy losses in the production of H_2 from renewable electricity and again energy losses in the production of LSM from H_2 and other inputs, it does not make sense for the power sector to shift to LSM: it would make more sense to sell renewable electricity directly or to store it as H_2 and convert H_2 into electricity in a power plant rather than converting it into CH_4 first.

It could be possible that the power sector would use (L)BM, although current and projected levelized costs of wind- and solar power (see Annex C) are well below the production costs of (L)BM, so it is unlikely that the power sector will use significant amounts of (L)BM in the long run.

Another reason why the power sector could continue the use of biomass is to generate negative emissions. Generating electricity with biomass, sequestering the CO_2 emissions and storing them would be one way to reduce the concentration of CO_2 in the atmosphere. Such negative emissions are a prevalent feature of emission scenarios consistent with the Paris Agreement temperature goals (IPCC, 2018).

Industry uses (L)NG to produce electricity or heat and/or uses it as a feedstock (‘non combusted’ in Figure 16). For the production of electricity or heat, it is unlikely that there will be significant demand for LSM or LBM for the same reasons as apply to the power sector.

(L)NG is a feedstock for the production of hydrogen. Since LSM is produced from hydrogen, we don’t expect demand for LSM to feed into this production process.

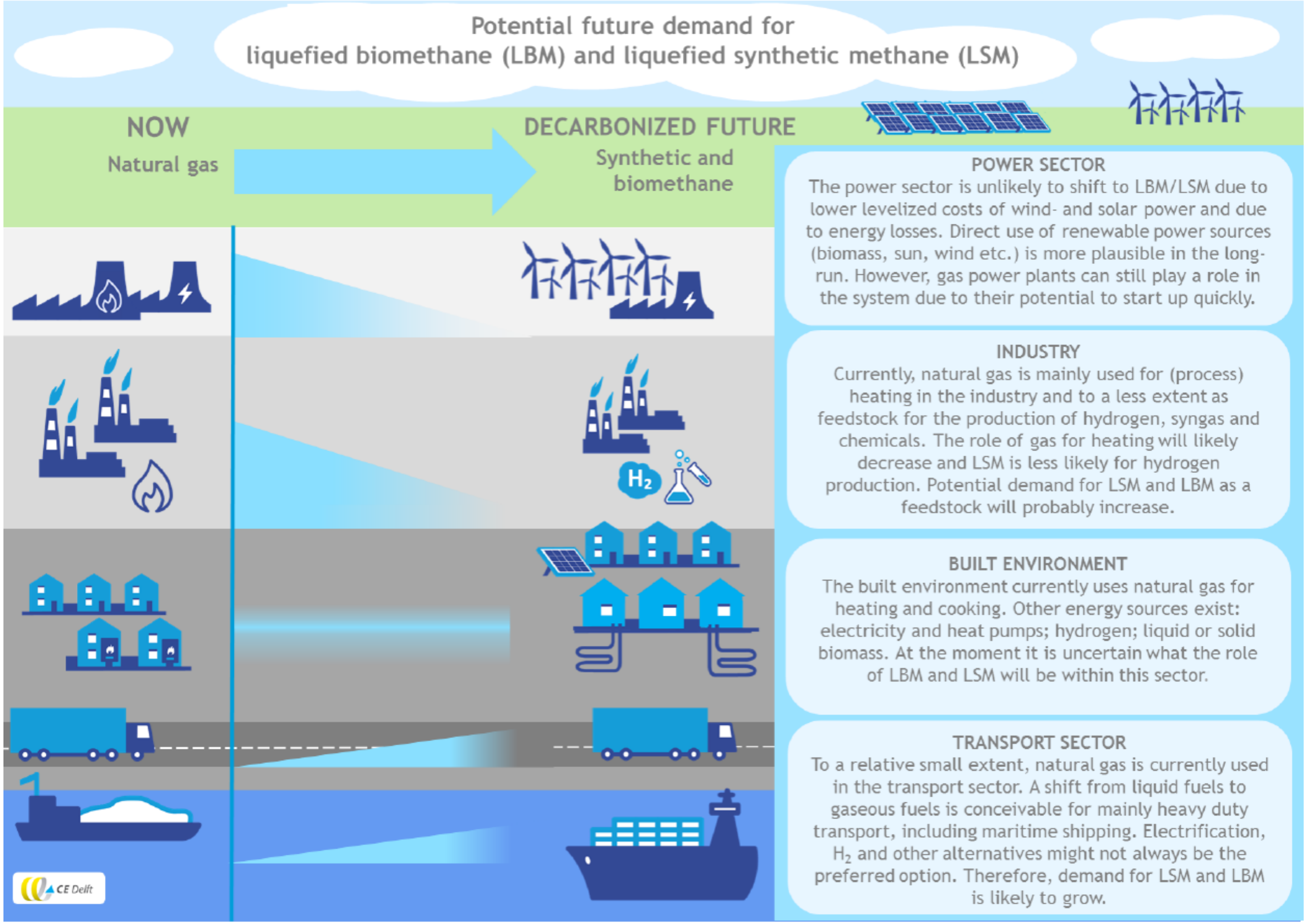
For other feedstock use, the industry may have a significant demand for LSM and LBM to replace natural gas in a decarbonised future.

The **built environment** uses (L)NG for heating and cooking. In principle, buildings can switch to other energy sources (electricity and heat pumps; hydrogen; liquid or solid biomass), but such conversion might require considerable collective investments in infrastructure and equipment which may be difficult to achieve, which is why there may be demand for (L)BM and (L)SM from buildings.

The use of (L)NG in the **transport sector** is currently low, but a shift from liquid fuels to gaseous fuels is conceivable for HGVs, inland vessels and non-road mobile machinery, although electrification and the use of H_2 are also possibilities. Note that LSM has an advantage over synthetic liquid hydrocarbons because methane can be produced more efficiently. Still, these sectors may also have a demand for LSM and LBM in a decarbonised future.

Owners of LNG-fuelled ships that want to switch to LSM/LBM might thus have to compete with the industry, the built environment and other transport sectors for LSM/LBM.

Figure 17 — Illustration of potential substitution of (L)NG by LSM/LBM in a decarbonised world



6 Recommendations on how barriers to scaling of LBM and LSM as marine fuel could be addressed

Chapters 2 and 3 demonstrate that sufficient amounts of biomethane or synthetic methane or a combination of these can be produced to fuel the entire shipping sector. Chapter 4 shows that carbon prices of USD 50–100 per tonne CO_2 will not be sufficient to make either biomethane or synthetic methane cost-competitive with fossil marine fuels. Chapter 5 concludes that in a decarbonized future, there will be competing demand for biomethane and synthetic methane from other sectors, such as land transport, the built environment and potentially industry.

This chapter addresses the question how barriers to scaling of LBM and LSM as marine fuel could be addressed. It first identifies the main barriers as well as the factors that are conducive to the uptake of LSM and LBM. Subsequently, it discusses how each of the barriers could be addressed, taking the conducive factors into account.

6.1 Barriers and conducive factors

The main barriers are the high price of LSM and LBM relative to other marine fuels; the relatively small (but growing) number of LNG ships in the current fleet; uncertainty about the climate impacts of LNG, LSM and LBM, in particular relating to methane slip and the climate impact of methane; and the fact that competing demand may come from sectors that are accustomed to blending mandates and to higher fuel prices.

Counter to the barriers, there are also factors that could contribute to scaling of LBM and LSM as marine fuel. One is that these are drop-in fuels and can be used by LNG-powered ships without modifications to the engine or the fuel system. They can also be mixed in all proportions with fossil LNG, thus creating a fuel with a specific net-carbon impact. Some of these factors are related to methane in general, regardless of whether it is fossil, synthetic or of a biological origin. The number of LNG-powered ships is increasing, amongst others due to tighter air-quality regulations. And finally, the number of ports offering LNG bunkering facilities is increasing rapidly in different parts of the world.

6.2 Measures in the shipping sector

We distinguish measures that can be taken in the shipping sector and measures in other sectors.

The shipping sector could take measures to enhance the demand for methane-powered ships in general and also measures that will increase demand specifically for the net-low- and net-zero-carbon varieties of methane.

The first category of measures comprises measures that reduce uncertainty about LNG as a marine fuel. These uncertainties relate to price, bunkering infrastructure and the climate impacts of methane.

Many of the first type of measures are already implemented. Standards, procedures and safety regulations have been developed in the last few years which is why we do not see any major institutional barriers to the use of LSM or LBM in shipping. ISO is currently also developing the ‘Specification of liquefied natural gas as a fuel for marine applications’ (ISO/DIS 23306). This should allow to get a better understanding of the quality of LBM that is required for use as marine fuel or for a blend of LNG and LBM or LSM as marine fuel. The EU and other world regions are increasing the bunkering infrastructure. LNG provides have various pricing options that alleviate some price risks.

MEPC is currently debating the carbon-emission factors of low- and zero-carbon fuels. There is a debate about whether well-to-propeller or tank-to-propeller emission factors should be used as a basis for future policy making. The climate impact of fuels is determined by the well-to-propeller emissions. LSM and LBM have worse tank-to-propeller emission factors than other low- or zero-carbon fuels like hydrogen or ammonia, which do not contain carbon. In addition, there remains uncertainty about the methane slip of bunkering, fuel systems and engines. The discussion would be helped with more empirical data of methane slip in real-world conditions.

These measures address, combined or in isolation, the barrier of the relatively small but increasing number of LNG-fuelled ships.

Specifically to increase demand for LSM and LBM from the shipping sector, measures would have to be adopted that increase demand for low- or zero-carbon fuels or energy carriers at the expense of fossil fuels. Obvious candidate measures would be a carbon levy, emissions trading or fuel standard. A carbon levy would need to be higher than USD 100 per tonne of CO_2 in 2030 in order to make LSM and LBM cost-competitive. Emissions trading could have a gradually lower cap so that allowance prices rise gradually to the required price level, and a gradually increasing amount of LSM and LBM would be required by the shipping sector. Likewise, a low-carbon fuel standard could mandate that ships gradually lower the average fossil carbon content of the fuels used.

This measure could address the barriers of the relatively high cost of LSM and LBM compared to other marine fuels, and the barrier that other sectors are already accustomed to blending mandates and to higher fuel prices.

6.3 Measures in other sectors

Although the potential supply of LSM and LBM is high, the actual supply is very low. Measures could be taken to enhance supply. Such measures can enhance supply directly or be aimed at creating demand in other sectors which will trigger supply.

Supply could be enhanced by fostering R&D that brings down the production costs of LBM and LSM

Regarding the supply side of LBM/LSM, there has to be sufficient overall demand for suppliers to have an incentive to produce LSM/LBM. This is comparable to the current situation – the marine sector would probably not have been able to use marine LNG if the demand of other sectors for natural gas had not lead to the establishment of LNG markets.

7 Conclusions

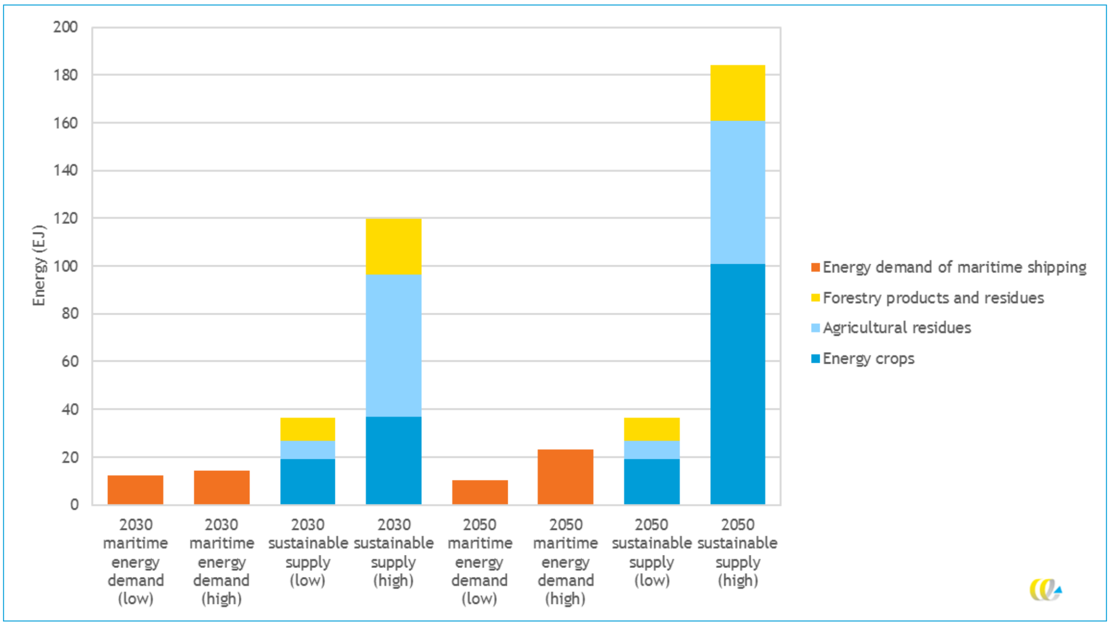
The aims of this study were to:
1. To assess the availability of LBM and LSM in relation to the global energy demand of maritime shipping.
2. To assess the cost price of LBM and LSM and to compare it with the cost (price) of other existing and potential marine bunker fuels.
3. To give recommendations as to how industry and policy makers could address barriers to the scaling of LBM and LSM as a marine fuel.

Conclusions for each of these subjects are presented below.

7.1 Availability of LBM and LSM

LBM can be produced from energy crops, agricultural residues, forestry products and revenues and from aquatic biomass. This study only takes biomass into account that can be produced in a sustainable manner. The feedstocks can be converted into biomethane either by anaerobic digestion, an established technology, or by gasification, which is being developed. The maximum conceivable sustainable supply of LBM is calculated by assuming that all sustainable biomass is converted into biomethane and subsequently liquefied. Figure 18 compares the maximum conceivable sustainable supply of LBM with the projected energy demand from the maritime sector in 2030 and 2050. In both years, the maximum conceivable supply is larger than the demand from the maritime sector. Note however that this analysis does not take into account that the actual production of biomass may be less than the maximum conceivable production, that not all biomass will be converted into methane and that there is competing demand from other sectors for methane.

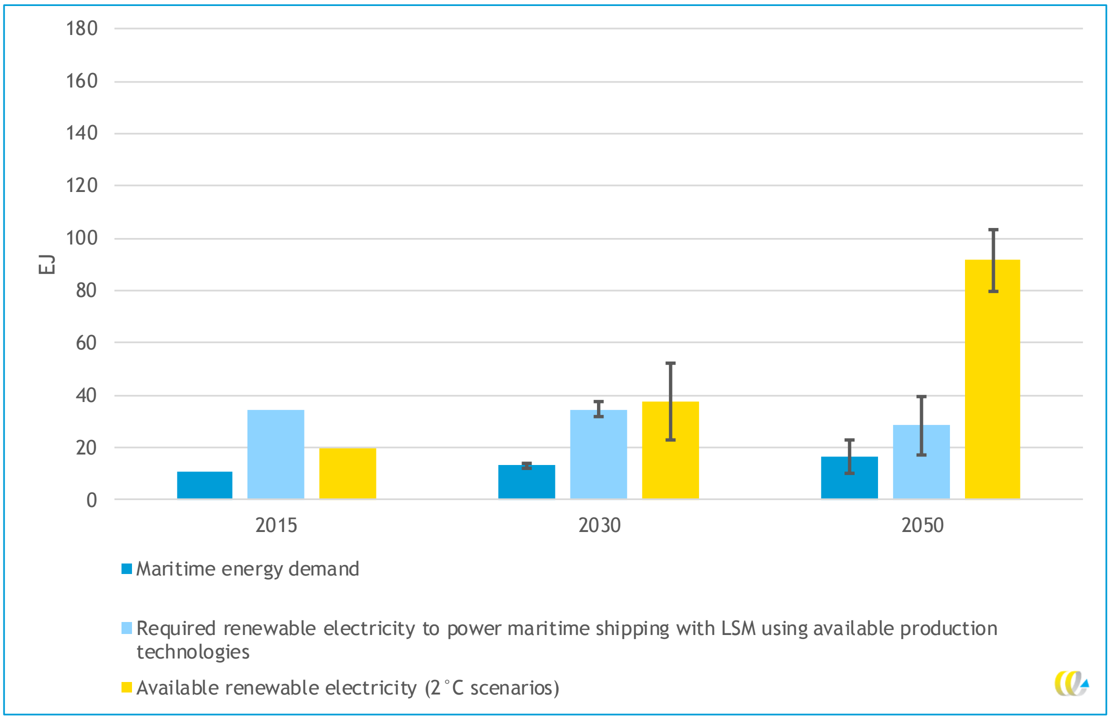
Figure 18 — Maritime energy demand and global maximum sustainable supply of LBM in 2030 and 2050, without aquatic biomass (EJ)



The production of synthetic methane is not limited by land availability in the same way as the production of biomethane is, because it doesn't require arable land. Therefore, the focus on the availability analysis is not on land availability and associated production capacity, but rather on the availability of the scarcest input in the production process: renewable electricity (all other inputs — hydrogen, fresh water, and carbon dioxide — are produced with renewable electricity). While the potential capacity of renewable electricity is very large, in practice it is constrained by the amount of investments.

Figure 19 shows the energy demand from maritime transport and the amount of renewable electricity that would be required to meet this demand with LSM. Because of projected improvements in the production process, the renewable electricity demand will decrease when the projected energy demand increases. The amount of renewable electricity required to produce LSM for the maritime sector is compared with the projected amount of renewable electricity that will be required to limit global warming to 2 degrees above pre-industrial levels. In 2050, an estimated 25-30% of renewable electricity would need to be produced in addition to the projected amount to decarbonise the maritime transport sector using LSM.

Figure 19 — Maximum potential supply of LSM compared with maritime energy demand given a renewable electricity supply in line with a 2°C degree scenario



7.2 Cost comparison

Comparing the expected 2030 per energy unit bunker prices of LBM, LSM and fossil LNG (including a carbon mark-up), fossil LNG is forecast to be the cheapest and LSM the most expensive bunker fuel in 2030. LSM can only become cheaper than LBM, if cheap renewable electricity is available and high electrolyser load factors can be achieved. A carbon mark-up of between 50–100 USD/t CO_2 is not expected to be sufficient to incentivize a switch from fossil LNG to LBM or LSM in 2030. However, a 2050 carbon price that is consistent with a well below 2°C mitigation pathway can be expected to incentivize a switch from fossil LNG to LBM, at least if the 2050 price for fossil LNG is not below its 2030 price.

Comparing plant gate costs of LBM and LSM with those of liquid hydrogen and liquid ammonia — two other renewable fuels — it can be concluded that:

- In an optimistic scenario (lower range of the cost estimates from the literature review),
  - Plant gate costs are broadly comparable for LBM, liquid ammonia and liquid hydrogen.
  - The costs of liquid ammonia are expected to be lowest, followed by the liquid hydrogen and LBM with LSM featuring the highest costs. Significantly lower liquefaction costs for ammonia can explain the cost differential between liquid ammonia and liquid hydrogen, but the presumed optimistic electricity price might also vary between the estimates.
- In a pessimistic scenario (higher range of cost estimates from the literature review), the costs of LBM are expected to be lowest, followed by liquid hydrogen; costs for both, liquid ammonia and LSM are relatively high and highest for LSM.

The optimistic scenario will probably only materialise for liquid hydrogen, liquid ammonia and LSM if the production location has favourable conditions for renewable electricity. This may require transportation of the fuels over longer distances, depending on the locations of the bunker ports.

If transported by ship, transportation costs can be expected to be lower for liquid ammonia compared to liquid hydrogen and LSM/LBM and for liquid hydrogen transportation costs can be expected to be higher than for LSM/LBM.

Since the production of LBM does not rely on the availability of cheap renewable electricity, this might allow for local production in the vicinity of major ports and could save out costs for the transport of the bunker fuel. Local production of LBM might require transport of biomass. These transport costs can be expected to be relatively low, at least if the biomass can be transported/is available in bulk.

Since the costs of the bunker infrastructure for hydrogen and ammonia are still very uncertain, the impact of these costs on the bunker fuel prices are difficult to assess at present. However, since the bunkering infrastructure of LBM and LSM are technically mature whereas the bunkering infrastructure for hydrogen and ammonia is technically still immature, the bunker price cost mark-up for the bunkering of hydrogen and ammonia can be expected to be higher than for LSM and LBM, at least in the short- and medium-run.

7.3 Recommendations for scaling up the use of LBM and LSM

In order to scale up the use of LSM and LBM, we recommend reducing the uncertainty about the use of methane as a fuel, especially with regards to methane slip and the associated climate impact. Policy measures like a fossil carbon levy, emissions trading or a low-carbon fuel standard could be implemented to shift the demand in the shipping sector from natural gas or liquid fossil fuels to LSM, LBM or other low- and zero-carbon fuels.

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A GHG-accounting methods for biofuel

There are different accounting methods to account for the GHG emissions from biofuels. The most important methodologies are the IPCC and EU Renewable Energy Directive (RED) and Fuel Quality Directive (FQD) methodologies, which differ substantially from each other, because each methodology serves a different purpose. Due to the differences between both methodologies it is hard to compare IPCC emission reductions to emission reductions in line with the RED and FQD methodology. The differences will be described shortly in the paragraphs below.

A.1 Intergovernmental Panel on Climate Change (IPCC)

Countries use the methodology of the IPCC to report on GHG emissions in relation to the Paris Agreement. National authorities use this methodology to report on their compliance with national targets as part of the overall international agreements. The reporting requirements prescribe this methodology to ensure uniform calculations and to avoid double counting between countries. Within the reports countries only take into account emissions on their national territories: international maritime and international aviation are therefore excluded. With respect to fuels, countries only report on the tank-to-wheel emissions of fuels i.e. the emissions that are emitted as result of combustion. Well-to-tank emissions, such as the emissions related to the production of the fuel are not taken into account: these emissions are attributed to the sectors and countries where the emissions actually occur. Both the national territory approach and TTW scope avoid double counting of emission savings. Because of the short life cycle of CO_2 in case of biomass utilisation no GHG emissions are allocated to the combustion of biofuels. Because biofuels count as zero emission, biofuels result in a 100% reduction compared to the use of fossil fuels according to the IPCC reporting standards.

A.2 Renewable Energy Directive and Fuel Quality Directive

The European RED and FQD use a life cycle approach, because these directives aim to increase the share of renewable energy in transport (preferably the biofuels with the highest emission savings) and to lower the average GHG intensity of fuels. A 10% share of renewable energy in transport in 2020 and at least 14% in 2030 and a reduction of 6% of the average GHG intensity of fuels by 2020 compared to 2010. In order to count towards the targets, biofuels have to meet sustainability criteria, including a minimum threshold for GHG emission savings over the lifecycle. Therefore a lifecycle approach is required, which makes. Fuel suppliers are obliged to report on the emissions over the entire life cycle of biofuels.

According to Annex V of the RED (2018/2001) (EU, 2018), GHG emissions from the production and use of biofuels shall be calculated as:

$$E = e_{ec} + e_{l} + e_{p} + e_{td} + e_{u} - e_{sca} - e_{ccs} - e_{ccr}$$

where

E = total emissions from the use of the fuel expressed in terms of grams of CO_2 equivalent per MJ of fuel (g CO_2-eq./MJ);
eec = emissions from the extraction or cultivation of raw materials;
el = annualised emissions from carbon stock changes caused by land-use change;
ep = emissions from processing;
etd = emissions from transport and distribution;
eu = emissions from the fuel in use;
esca = emission savings from soil carbon accumulation via improved agricultural management;
eccs = emission savings from CO_2 capture and geological storage; and
eccr = emission savings from CO_2 capture and replacement.

In this life cycle approach, the actual CO_2 emissions emitted during combustion are accounted for and thus not set to zero, but the CO_2 captured in the biomass in the first instance can be deducted. If GHG emissions are avoided by the use biomass for biofuel purposes (e.g. using manure for biogas production instead of spreading it on agricultural land) this is accounted for here too.

Emissions from the manufacture of machinery and equipment shall not be taken into account.
The RED also does not include emissions from indirect land use change (ILUC).

The outcome of the calculation provides the actual value. Instead of the actual value, default values might be used. Default values are derived from a typical value by the application of pre-determined factors and may be used in place of an actual value. Using default values lowers the administrative burden for market actors. In order to determine the emission reduction of biofuels compared to fossil fuels, the fossil fuel comparator is 94 g CO_2-eq./MJ.

Compared to the RED, the FQD includes provisional estimated indirect land-use change emissions (as malus) and a bonus of 29 gCO_2-eq./MJ biofuel if biomass is obtained from restored degraded land. Note that the RED II already covers the period 2020-2030, while the most recent version of the FQD (2009/30/EC) , including the amendments of the ILUC Directive (2015/1513)) still covers the period up to 2020. Therefore some differences might occur, but the life cycle approach is similar.

Both directives also include minimum GHG requirements as part of the sustainability criteria. The revised RED (2018/2001) includes the minimum GHG requirements as depicted in Table 36. The thresholds should be calculated using the life cycle approach of the methodology as laid down in Annex V of the directive.

Table 36 — GHG saving thresholds in RED II

Plant operation start data	Transport biofuels	Transport renewable fuels of non-biological origin (such as hydrogen)	Electricity, heating and cooling
Before October 2015	50%	-	-
After October 2015	60%	-	-
After January 2021	65%	70%	70%
After January 2026	65%	70%	80%

B Production capacity of electrolysers

This annex analyses the production capacity of electrolysers. The electrolysers currently on the market are either AEC or PEM. The aspects taken into account in the evaluation are:

1. Technological maturity and characteristics.
2. Efficiency (current and potential future improvement).
3. Capacity.

B.1 Technology maturity and characteristics

Table 37 shows some of the key indicators which would help us assess the current and the future status in terms of electrolysis technology that will play a major role in the hydrogen electrolysis hence helping us in choosing the most suitable electrolysis technology based on few key criteria's (Mention the criteria's below). Both (Selma, et al., 2018) and (Imperial College London, 2017) have been used as the source to present the below indicators. For indicators that we could not get the latest data, we have mentioned the date aside the indicator for reference.

Table 37 — AEC and PEM indicators based on 2015-2017 data

Indicators	AEC	PEM
Electrolyte	Aq.potassium hydroxide	Polymer membrane
Cathode	Ni, Ni-Mo alloys	Pt, Pt, Pd
Anode	Ni, Ni-Co alloys	RuO2, IrO2
Current density (A cm^{-2})	0.2-0.4	0.6-2.0
Voltage efficiency (%)	62-82	67-82
Operating temperature (°C)	60-80	50-80
Operating pressure	< 30	< 200
Production rate (m^3 H_2 h^{-1})	< 760	< 40
Gas purity (%)	> 99.5	99.99
Cold start time (min)	< 60	< 20
System response	Seconds	Milliseconds
Stack life time	60,000-90,000	20,000-60,000
Systematic lifetime (years)	20	20
Maturity	Mature	Commercial
Capital cost (EUR 2015/kW)	600-2,600	1,900-3,700
Operational & maintenance cost (% to their investment cost)	2-5%	2-5%
Electricity to hydrogen efficiency (%)	43-69	40-69
Stack replacement cost	50% of investment cost	60% of investment cost
TRL Level	9	9
Flexibility (fluctuating renewable electricity)	Yes	Yes

Source: (Selma, et al., 2018), (E4tech, 2014) and (IRENA, 2018a).

Efficiency

Typical efficiencies (energy output vs energy input) are currently stated to be around 65-75% for power to hydrogen using low temperature electrolysis (E&E, 2014). Currently, electrolysers achieve their best efficiency under steady currents. PEM is better suited to operate at partial loads and to deal with fluctuating energy supply than AEC. If the heat released by each of these processes is recovered and used, production efficiency can increase to 85% by 2030 (E&E, 2014) (Naimi, 2019).

Capacity

To date, about 4% of global hydrogen supply is produced via electrolysis (IRENA, 2018a). Most of this is probably produced with AEC, which are larger scale than PEM and require lower costs (Leeuwen, 2018), (Maria Taljegard, 2016).

Conclusion

In order to produce quantities of hydrogen that are sufficient to power a significant share of the world fleet with synthetic methane, the capacity of electrolysers needs to increase significantly. There are several mature technologies and most observers agree that further technological progress is possible.

C Levelized costs of renewable electricity

Table 38 gives the global weighted-average Levelized Costs of Electricity (LCOE) for renewable power plants commissioned in 2018 for the different renewable power generation technologies for plants commissioned in 2018.

Table 38 — Global weighted-average LCOE of utility-scale renewable power generation technologies for plants commissioned in 2018

Renewable power generation technology	LCOE [USD/MWh]
Hydro	47
Onshore wind	56
Geothermal	70
Solar PV	85
Offshore wind	127
Concentrating solar power	185

Source: IRENA (2019a).

According to IRENA (2019b), the LCOE for onshore wind is already competitive compared to all fossil fuel generation sources and is set to decline further as installed costs and performance continue to improve.

Globally, the LCOE for solar PV is expected to fall to between 20 to 80 USD/MWh by 2030 and between 14 to 50 USD/MWh by 2050 (IRENA, 2019c).

The LCOE of offshore wind is already competitive in certain European markets and is expected to become competitive in other markets by 2030. The LCOE of offshore wind is expected to drop to an average between USD 50 to 90/MWh by 2030 and USD 30 to 70/MWh by 2050 (IRENA, 2019b).

D Production cost estimations

D.1 Ammonia

Table 39 — Production cost estimates of renewable ammonia as can be found in the literature

Source	Production cost estimate	Conversion to 2019 USD/MMBtu	Underlying assumptions
(IEA, 2019d) The Future of Hydrogen	Figure 31: – EU import from North Africa: 3.8 USD/kg H_2 – Import to Japan from Australia/Middle East: 4.3-5.2 USD/kg H_2	– EU import from North Africa: 33 USD/MMBtu – Import to Japan: 37-45 USD/MMBtu	2030 costs Hydrogen importing costs excluding reconversion of ammonia to hydrogen; transportation costs are included. Long term renewable electricity price: 18-63 USD/MWh.
(Lloyd's Register; UMAS, 2019) Fuel production cost estimates and assumptions, Figure 2	2030: 60 USD_{2019}/MWh 2050: 30 USD_{2019}/MWh	2030: 18 USD/MMBtu 2050: 9 USD/MMBtu	
(Siemens Gas and Power, 2019) Transformation: A new era for the agri-nutrients industry	Production costs: First projects today: 800 USD/t; 500-600 USD/t ammonia is achievable (mature case in 5-10 years)	Today: 45 USD/MMBtu Mature case in 5-10 years: 28-34 USD/MMBtu	Mature case in 5-10 years: WACC of 5% LCOE of less than 30 USD/MWh_e.
(Rivarolo, et al., 2019) Clean Hydrogen and Ammonia Synthesis in Paraguay from the Itaipu 14 GW Hydroelectric Plant	"For all the investigated sizes, ammonia production costs are lower than 400 EUR/ton" [332-383 EUR/ton]	21-24 USD/MMBtu	Installed power of electrolyser scenarios: 80-600 MW While for lower capacity plants the fixed costs are more significant than variable costs (electrical energy), for higher sizes the situation is the opposite, as electricity has an higher cost (30 EUR/MWh).
(University of Minnesota, 2019) Comparative Technoeconomic Analysis of Absorbent-Enhanced and Traditional Ammonia Production	Graph slide 14: Levelized costs 500-770 USD/ton ammonia	28-43 USD/MMBtu	
(CE Delft, 2018b) Waterstofroutes Nederland - Blauw, groen en import	If produced in Morocco: 2017: 3.87 EUR_{2017}/kg H_2 2030: 2.0 EUR_{2017}/kg H_2 (NH_3 production costs on top of hydrogen production costs: 2017: 0.33 EUR_{2017}/kg H_2 2030: 0.29 EUR_{2017}/kg H_2)	If produced in Morocco: 2017: 38.4 USD/MMBtu 2030: 19.8 USD/MMBtu (NH_3 production costs on top of hydrogen production costs: 2017: 3.3 USD/MMBtu 2030: 2.9 USD/MMBtu)	Study investigates, amongst other things, costs for importing green hydrogen to the Netherlands, with the hydrogen being produced in Southern Europe or North Africa by means of

Source	Production cost estimate	Conversion to 2019 USD/MMBtu	Underlying assumptions
			dedicated wind and solar power. To reduce the volume for transport, hydrogen is assumed to be converted into ammonia. Electricity costs: – 2017: EUR34/MWh – 2030: EUR23/MWh
(Cerulogy, 2017) What role for electromethane and eletrocammonia technologies in European transport's low carbon future? (Figure 4)	2018 costs: – High case: 6,900 €2018/toe – Base case: 2,400 €2018/toe – Low case: 1,400 €2018/toe 2030 costs: – High case: 3,500 €2018/toe – Base case: 2,000 €2018/toe – Low case: 1,300 €2018/toe	2018 costs: – High case: 207 USD/MMBtu – Base case: 72 USD/MMBtu – Low case: 42 USD/MMBtu 2030 costs: USD/MMBtu – High case: 105 USD/MMBtu – Base case: 60 USD/MMBtu – Low case: 39 USD/MMBtu	High case: small synthesis facility/worst case electrolysis costs. Low case: large synthesis facility/best case electrolysis costs.
(IEA, 2017c) Renewable Energy for Industry, From green energy to green materials and fuels	Under the most favourable conditions, the cost of producing green ammonia would be around USD 400/t NH_3, assuming an electricity price of USD 30/MWh if electricity is available in large enough quantities for the load factor of the electrolysers to be at least 50%. The cost under less ideal circumstances would be USD 700/t NH_3 with electricity at USD 60/MWh and an electrolyser load factor of 30%.	Most favourable conditions: 24 USD/MMBtu Less ideal circumstances: 41 USD/MMBtu	
(ISPT, et al., 2017) Power to Ammonia	Business case 3 (dedicated renewable power): NH_3 costs are between 365 and 500 EUR/ton, and with a combination of optimistic assumptions on CAPEX and power price, a NH_3 cost of 260-370 EUR/ton can be achieved.	Full range: 24- 33 USD/MMBtu Optimistic range: 17–25 USD/MMBtu	For the cost calculations of the business cases it is assumed that supply of NH_3 will start per 1-1-2026.
(University of Oxford, 2017) The role of 'green' ammonia in decarbonising energy	2025/2030 estimate using all 5 key variables: 588 GBP/tonne of ammonia	43 USD/MMBtu	
(University of Oxford, 2015) Analysis of Islanded Ammonia-based Energy Storage System	This calculation returned a LCOA value of 655 USD/ton NH_3	39 USD/MMBtu	Techno-economic analysis of an ammonia-based energy storage system integrated with renewable electricity generation on an island system (a power network which is not connected to the grid);

Source	Production cost estimate	Conversion to 2019 USD/MMBtu	Underlying assumptions
			Levelized electricity cost of the islanded system was estimated at 251 USD/MWh.

D.2 Hydrogen

Table 40 — Production cost estimates of renewable hydrogen as can be found in the literature

Source	Production cost estimate	Conversion to 2019 USD/MMBtu	Underlying assumptions
(IEA, 2019d) The Future of Hydrogen, Figure 16	2-4 USD/kg H_2	17-35 USD/MMBtu	2030 hydrogen production costs in Europe.
(IRENA, 2019d) Hydrogen: A renewable energy perspective	Hydrogen production costs: – average wind: 3.2 USD/kg H_2; – average PV: 2.8 USD/kg H_2.	Hydrogen production costs: – average wind: 28 USD/MMBtu; – average PV: 25 USD/MMBtu.	2030 costs.
(Lloyd's Register; UMAS, 2019) Fuel production cost estimates and assumptions, Figure 2	35 USD_{2019}/MWh	10 USD/MMBtu	2030 costs; hydrogen from renewable electricity (liquefaction storage).
(CE Delft, 2018b) Waterstofroutes Nederland - Blauw, groen en import	1.7-2.9 EUR_{2017}/kg H_2	18-30 USD/MMBtu	2030 production costs, depending on production location (Morocco or Netherlands).
	2.2 EUR_{2017}/kg H_2	23 USD/MMBtu	2030 costs including transportation from Morocco to the Netherlands, excluding liquefaction costs.
(FVV, 2018), Defossilisierung des Transportsektors, Optionen und Voraussetzungen in Deutschland	Local production: 0.18 EUR/kWh Centralized production: 0.08 EUR/kWh	Local production: 28 USD/MMBtu Centralized production: 63 USD/MMBtu	2030 low cost scenario (high efficiency, low electricity prices from MENA region); centralized production: non-dedicated renewable electricity production.
(Frontier Economics, 2017) PtG/PtL-Rechner: Berechnungsmodell zur Ermittlung der Kosten von Power-to-Gas (Methan) und Power-to-Liquid. Model version 1.0	5-13 EUR $Cent_{2017}$/kWh H_2	18-45 USD/MMBtu	2030 production costs, depending on production location (Iceland, Middle East, North Africa, Germany).
(IRENA, 2019d) Hydrogen: A renewable energy perspective	Hydrogen production costs: – average wind: 2 USD/kg H_2; – average PV: 1 USD/kg H_2.	Hydrogen production costs: – average wind: 17 USD/MMBtu; – average PV: 9 USD/MMBtu.	2050 costs.
(Lloyd's Register; UMAS, 2019) Fuel production cost estimates and assumptions. (Figure 2)	20 USD_{2019}/MWh	6 USD/MMBtu	2050 costs; hydrogen from renewable electricity (liquefaction storage).

Source	Production cost estimate	Conversion to 2019 USD/MMBtu	Underlying assumptions
(Frontier Economics, 2017) PtG/PtL-Rechner: Berechnungsmodell zur Ermittlung der Kosten von Power-to-Gas (Methan) und Power-to-Liquid. Model version 1.0	4-8 EUR-Cent$_{2017}$/kWh H_2	14-27 USD/MMBtu	2050 production costs, depending on production location (Iceland, Middle East, North Africa, Germany).