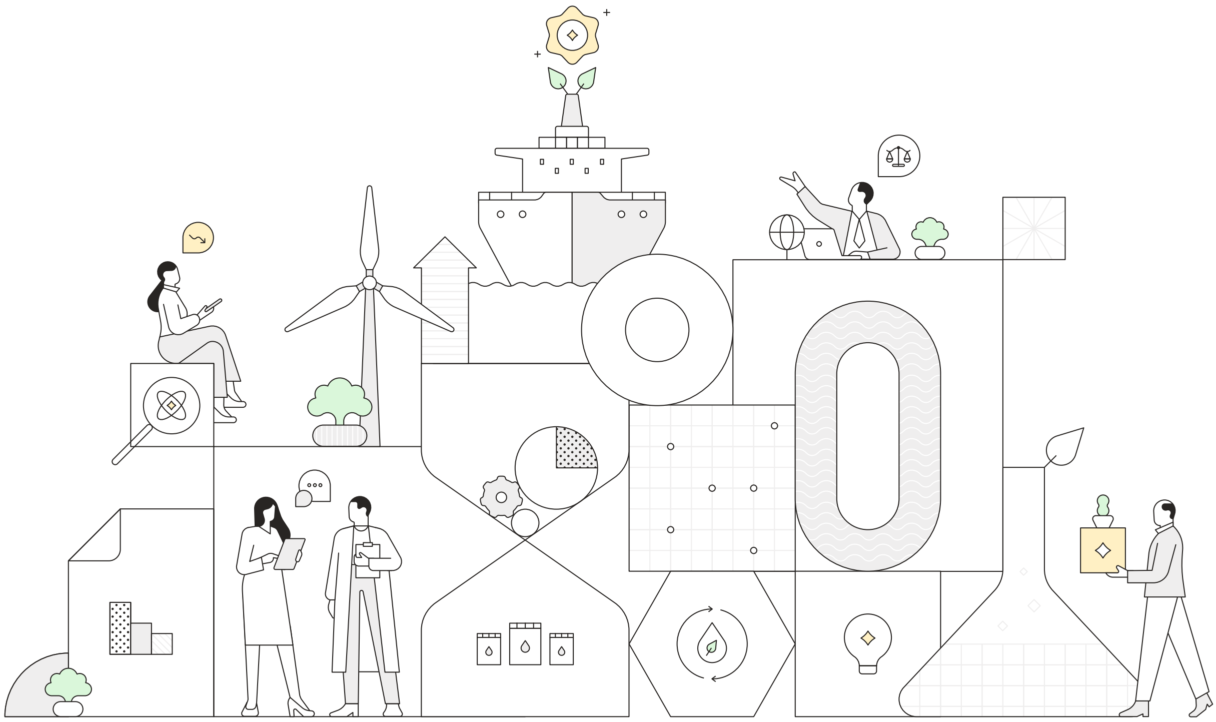
Biogas as a Source of Biofuels for Shipping

Methane Emissions

Mærsk Mc-Kinney Møller Center
for Zero Carbon Shipping

Contents



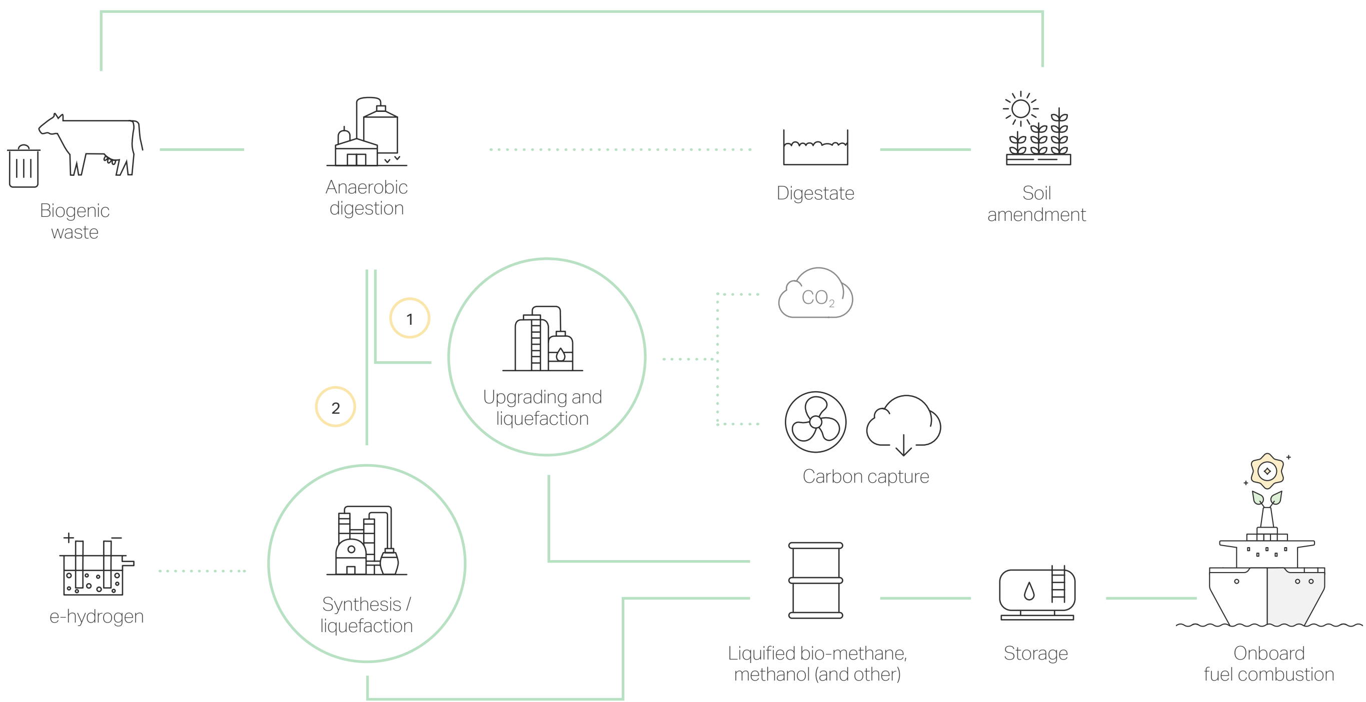
Executive Summary

Effective decarbonization of the shipping industry will require the adoption of a mix of alternative marine fuels. To support this transition, this series of reports presents a deep dive into the potential of biogas as a source of biofuels for shipping. Biogas, generated by anaerobic digestion of biogenic waste, is a mixture of methane (CH_4) and carbon dioxide (CO_2) that can be easily converted into various biofuels. In this series, we explore the production of liquified bio-methane (LBM) and bio-methanol from biogas (Figure 1).

Biogas-based biofuels can be produced using fully commercial conversion technologies. By using waste as input feedstock, anaerobic digestion contributes to solving a waste management problem, producing both biogas and a valuable natural fertilizer (digestate) in the process. Support infrastructures for this production pathway exist in many countries, capacities can be scaled up to an attractive level, and the resulting biofuels can have strong value for money. One of our greatest areas of concern is emissions of methane, a potent greenhouse gas (GHG), along this value chain. For this study, we reviewed public information and spoke to experts to understand the extent of the problem of methane emissions associated with biogas-based biofuels, the steps in the value chain where it appears, how emissions can be measured, and whether and how they can be mitigated.

Methane's lifetime in the atmosphere is much shorter than that of CO_2, but it can trap considerably more heat. Accounting for methane's global warming potential (GWP) therefore depends on the timeframe considered. Current regulatory practices tend to account for the long-term effect, putting methane's GWP value over 100 years (GWP100) at 28 times that of CO_2. However, methane's impact on global warming is much higher in the short term. Accordingly, methane's GWP over 20 years (GWP20) is more than 80 times that of CO_2.

Figure 1: Schematic of a generalized value chain for biofuels from biogas.



We found that methane emissions are difficult to fully quantify, and their thorough assessment requires specialized knowledge and measurement techniques. Such specialized assessments reveal that methane emissions can appear during biofuel processing, transport, and usage – and they do, occasionally in whopping amounts where regulations are absent.

Methane emissions can be mitigated via a combination of good practice in engineering design, correct equipment selection, and proper management of operations. Technologies that minimize emissions already exist, and innovations that further improve methane control are on their way to commercialization. We found examples of successful mitigation of methane emissions when operators engage actively in the mitigation effort. Motivation to mitigate methane emissions is typically based on economic reasons (loss of product), a genuine desire to decarbonize own operations, or the need to comply with regulations. Real-world examples show that regulations are extremely effective, with best-in-class fossil methane production claiming methane losses below 0.03%. However, while specific regulations governing methane emissions from biogas-based value chains are appearing, they are still scattered.

Focusing on the production and use of biofuels from biogas as marine fuels, we found that most emissions occur during biogas manufacturing, particularly anaerobic digestion and digestate management. The second-largest source of emissions is use of LBM as a marine fuel, due to methane slip from onboard combustion. Based on our study, typical overall methane losses from biogas-based LBM value chains in shipping may be in the range of 5-6%. For other biogas-based biofuels that do not generate onboard methane emissions, such as bio-methanol, the overall methane losses are around 2-3%. However, methane losses 2-3 times higher than these typical levels are also conceivable.

We next calculated the well-to-wake GHG emissions from theoretical value chains for biogas-based biofuels using a set of representative assumptions and different methane emissions scenarios. Based on these assumptions and using methane's GWP100, value chains affected by "typical" methane losses comply with established sustainability criteria, such as the European Union's Renewable Energy Directive (RED) II, and offer acceptable options for decarbonization. The emissions intensity of these biofuels is in the range of 18 to 28 gCO_2eq/MJ. If the CO_2 generated during manufacturing is captured and stored (CCS), the value chains have negative emissions intensity (-16 to -24 gCO_2eq/MJ) and offer excellent decarbonization options. However, if methane losses was to be increased by 50%, only the value chains that include CCS would remain attractive from a decarbonization perspective.

Based on our review, overall methane losses below 1% from these value chains seem achievable, at least for new plants and ships that select appropriate equipment. Therefore, we next calculated the emissions intensity of biogas-based biofuels from theoretical value chains with 0.5% methane losses ("tight" value chains). Based on methane's GWP100 value, we found that emissions intensity was reduced by 15 to 30 gCO_2eq/MJ, depending upon the pathway. Pathways that included CCS achieved deeply negative emissions intensities. This massive reduction in emissions intensity has important consequences for a given biofuel's emissions reduction potential and therefore its value. In fact, the amount of a given biofuel required to achieve a certain decarbonization target can be reduced by 25% if the emissions intensity is reduced from 20 to -10 gCO_2eq/MJ, and by 50% if the emissions intensity is reduced from 20 to -50 gCO_2eq/MJ.

We next investigated the impact of applying a GWP20 value for methane rather than GWP100. Using a GWP20 value of 80, we found that biofuels from value chains with typical methane emissions would not comply with sustainability criteria unless CCS were applied. However, this change would have almost no effect on biofuels from tight value chains, which would all qualify with very attractive emissions reduction potentials. Thus, tight value chains are not only more economical, but also reduce the risk of non-compliance with potentially more stringent future regulation.

We emphasize that methane emissions from biogas-based value chains must be reined in if the industry is to be seen as genuinely climate-friendly. Based on methane losses of 5-6% along the value chain, the overall emissions from planned bio-methane production and use in Europe alone may result in the release of 1-1.5 million tonnes of methane per year into the atmosphere by 2030. This number corresponds to around 40 million tonnes of CO_2-equivalent using GWP100, or 110 million tonnes using GWP20. For context, current difficult-to-abate CO_2 emissions from European shipping are around 250 million tonnes.

These emissions are avoidable and particularly easy to mitigate in new production facilities and ships engineered with methane emissions reduction in mind. Both plant and ship owners and operators must urgently recognize the problem of methane emissions and act accordingly.

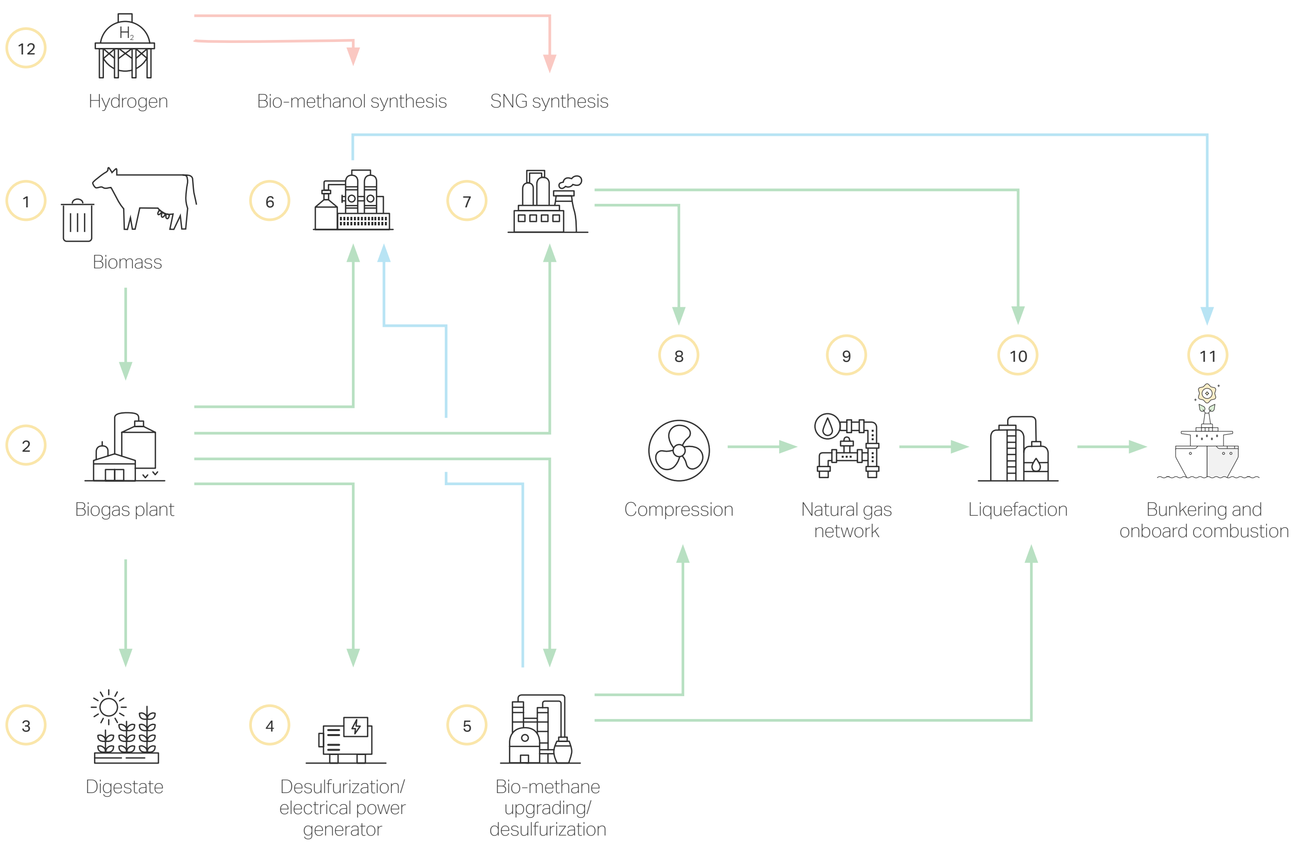
While shipping must decarbonize on par with the rest of society, GHG emissions can be reduced rapidly if the problem of methane emissions is addressed with the greatest urgency. We recommend that shipping operators considering biogas-based biofuels as part of their decarbonization strategy actively enquire about methane emissions from the value chain (including in their own ships) and ensure that these emissions are mitigated to the extent possible. Considering the difficulty of measuring methane emissions, independent certification may be necessary to demonstrate emissions mitigation claims.

1. Introduction

Switching from fossil-based to alternative marine fuels is a key prerequisite for decarbonization of the shipping industry. Biogas-based biofuels represent an attractive option as part of the alternative fuel mix available to the industry, especially in the shorter term. Biogas is a gas composed mainly of methane (CH_4) and carbon dioxide (CO_2), produced by anaerobic digestion of biomass. Notably, biogas can be used to produce both liquified bio-methane (LBM), a drop-in replacement fuel for liquified natural gas (LNG), and bio-methanol, tapping into the growing industry interest in methanol-fueled vessels. More detailed context on the background, advantages, and challenges surrounding these biogas-based biofuels can be found in our companion publication 'Insights into the value chain'.

Biogas is produced from biomass in a biological anaerobic digestion process driven by bacteria. Figure 2 shows the main elements of the value chains for producing bio-methane and bio-methanol from biogas for shipping. In brief, biomass (1) feeds the anaerobic digester at a biogas plant (2). This produces both biogas and digestate (3), a byproduct which is returned to agricultural fields as a soil amendment. The biogas can be burned in electrical power generators (4) to produce electricity or purified in an upgrader (5) to remove CO_2. The CO_2 separated in the upgrader may be further processed to synthesize bio-methanol (6) or, without prior separation, to increase methane production by converting CO_2 to methane in the form of synthetic natural gas (SNG) (7). Both processes require

Figure 2: Overview of methane emissions in the value chain of biofuels (bio-methane and bio-methanol) from biogas. Green lines show processes where methane emissions can occur. Bio-methanol production and use (blue lines) per se is not associated with methane emissions but may entail methane emissions during biogas manufacturing. Pink lines show processes where hydrogen emissions may occur.



reaction with hydrogen (12). The methane from an upgrader (5) or an SNG plant (7) can be compressed (8) and injected into the natural gas grid (9), or it can be liquified (10) to produce LBM. If trading schemes for green certificates exist, bio-methane from the natural gas network may also be liquified (10) to produce LBM. LBM and bio-methanol can then be used as biofuels on a ship (11).

A growing body of evidence indicates that methane, a potent greenhouse gas (GHG), is emitted at various stages of these value chains (green lines in Figure 2). Methane emissions are a critical area of concern for low-carbon energy pathways, as they have the potential to negate the climate benefits that these biofuels are expected to provide.

Drawing on both literature reviews and discussions with experts, this report surveys methane emissions in biogas-based value chains for LBM and bio-methanol, consolidates typical values, and reports on causes of these emissions and prospects for their reduction. This survey provides supporting data for our companion studies on energy demand and emissions reduction compliance and well-to-wake (WTW) GHG emissions.

As highlighted in Figure 2, production of both bio-methane and bio-methanol from biogas can entail methane emissions during the biogas production stage. In subsequent stages, bio-methanol's use as fuel is not associated with methane emissions. By contrast, LBM is associated with methane emissions throughout its life cycle. Bio-methane is also a more commercially established product than bio-methanol and consequently has more relevant data available. For these reasons, this report has a greater overall focus on bio-methane than on bio-methanol from biogas.

1.1 About this project

This study forms part of a broader project established to understand the hurdles to a widespread adoption of biogas-based LBM and bio-methanol fuels in shipping and to offer strategies for resolving these hurdles.

This report is part of a series on "Biogas as a source of biofuels for shipping". Other reports in this series deal with insights into the value chain, energy demand for emissions reduction compliance, WTW GHG emissions, techno-economic trends, and biomass availability.

The project was a collaboration between the Mærsk Mc-Kinney Møller Center for Zero Carbon Shipping (MMMCZCS) and our partners and mission ambassadors — Maersk, Topsoe, TotalEnergies, Norden, Cargill, Boston Consulting Group, Wärtsilä, and Novonesis. Several additional individuals and organizations contributed to the study. A full list of project participants is provided in Section 8.

Our project partners

BOSTON CONSULTING GROUP

Cargill

NORDEN

novonesis

MAERSK

TOPSOE

TotalEnergies

WÄRTSILÄ

2. Climate impact and regulation of methane emissions

2.1 Climate impact of methane emissions

Methane is an important GHG, with an effect on global warming arguably many times greater than that of CO_2. The extent of the problem caused by methane emissions has been underrecognized by policymakers and industry in the past, and methane leaks have been managed only to avoid safety issues and loss of profitability. As methane has traditionally been a low-price chemical, loss of methane as a product has not been a sufficiently strong driver to prevent large volumes of methane from being released every year. As a result, anthropogenic methane emissions are today responsible for approximately 30% of the total global temperature increase since pre-industrial times.[1]

As a so-called 'short-lived GHG' — meaning that methane persists in the atmosphere for 7-12 years, while CO_2 persists for hundreds of years[2] — the contribution of methane to global warming depends upon the time horizon. Therefore, there is an intense scientific debate on how best to account for this contribution. The Intergovernmental Panel on Climate Change (IPCC) Sixth Assessment Report (AR6) Working Group I (WGI) (Chapter 7.6.1) consolidates estimates of the global warming potential (GWP) for fossil and biogenic methane for various time horizons.[3] These estimates established GWP characterization factors for methane with respect to CO_2 of nearly 30 over 100 years (GWP100) and around 80 over 20 years (GWP20). Fossil and biogenic methane have slightly different emissions metrics based on their different effects on the carbon cycle.

Some authors advocate for the importance of reporting both the 100- and 20-year time scale.[4] Both the IPCC AR6 report[5] (Figure 7.22) and Lynch et al[6] have modeled the effect of GWP20, GWP100, and other metrics on the Earth's surface air temperature in various policy scenarios. They concluded that both GWP100 and GWP20 underestimate the short-term effect of methane on surface temperature and overestimate the long-term effect. Lynch et al[6] found that newer metrics (e.g., GWP*)[7] gave a better prediction of the modeled global surface air temperature, but proposals to adopt these newer metrics have generated controversy.[8,9]

As GWP metrics are used for policymaking, they have important implications for prioritization of which emissions to abate. Reflecting the fact that the appropriate emissions metric depends upon the purpose of the application, the IPCC leaves the choice of metric to policymakers. The MMMCZCS has previously studied fuel life cycle methodologies[10] and endorses the use of GWP100 as in the United Nations Framework Convention on Climate Change (UNFCC).[11] However, to account for the nuances in the scientific debate, we also verified how our conclusions would change if GWP20 were used instead (see Section 6).

2.2 Regulation of methane emissions

To correct the previous under-recognition of methane emissions, the European Union (EU) and the United States (US) launched the Global Methane Pledge (GMP) in 2021 at the 26th conference of the parties (COP26) in Glasgow. The GMP articulates a collective goal of reducing anthropogenic methane emissions by at least 30% from 2020 levels by 2030.[12] Since its initial signature, the number of countries adhering to the pledge has grown to 150. Still, as of January 2023, only one-third of the signatories had enshrined the pledge in methane action plans or had even committed to do so.[13] Regulations are widely seen as being critical to achieving excellence in methane emissions avoidance, as the top performance of Norway testifies.[14] Norway began regulating methane emissions a decade ago and consequently records close to nil emissions based on satellite measurements. Equinor, the Norwegian-based integrated oil and gas company, reports methane losses of less than 0.03% from its own operations and 0.3% from value chains distributing Equinor-produced methane to Europe.[15]

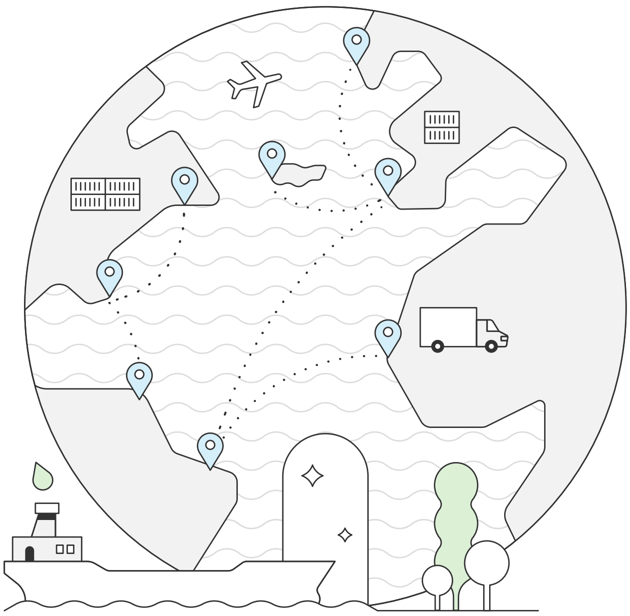
Methane emissions from shipping are likewise increasingly recognised as an issue.[16,17,18] Sea-LNG, the global coalition of organizations that promotes the use of LNG as a bunker fuel, has recently called on the International Maritime Organization (IMO) to regulate all shipping emissions, including methane, on a WTW basis.[19]

To our knowledge, legal requirements to mitigate methane emissions from anaerobic digestion or biogas production are mostly in the early stages. The International Energy Agency (IEA) maintains a list of policies intended to reduce methane emissions.[20] So far, regulators have focused on curbing the largest source of emissions, and biogas production plants have thus been largely exempted. In November 2023, the EU agreed upon a breakthrough new law to reduce methane emissions from fossil energy (exploration, production, transmission, distribution, storage, and LNG terminals).[21] Unfortunately, this law does not encompass agricultural emissions or biogas production plants. Similarly, the Methane Emission Charge of 900/1500 (immediately/after two years, respectively) USD per megaton (Mt) methane stipulated by the US Inflation Reduction Act applies only to methane emitted from facilities that are required to report their GHG emissions to the Environmental Protection Agency (EPA) under the Greenhouse Gas Emissions Reporting Program.[22] These facilities are large emitters (above 25,000 Mt CO_2eq/year, mostly involving fossil fuels), and therefore the scheme does not include biogas production plants.[23]

The European Biogas Association (EBA) has recently surveyed methane emissions mitigation policies in the context of biogas in Europe.[24] The study found a somewhat scattered regulatory panorama, comprising regulations on digestate management (France, Germany, Italy); limits on the permitted slip from upgraders (Germany, France) and electrical power generators (Germany); and schemes for self-inspection (Sweden, Denmark, Switzerland). In addition, Denmark has also imposed limits on emissions from upgraders as of 1 January 2023.[25]

Biogas already represents a sizable share of the energy supply in some countries (currently 40% in Denmark)[26] and thousands of plants will be built to satisfy renewable energy targets (see also our companion report on insights into the value chain). Individual biogas plants may remain small with respect to fossil assets, but their aggregated fugitive emissions may become an important component of national emissions in the absence of effective mitigation. We estimate such aggregated emissions for the European biogas industry in Section 4.8 of this report.

Considering the enormous interest that biogas is currently enjoying,[27,28] it is critical to effectively control methane emissions from biogas-derived biofuels to ensure that the opportunity from their broader adoption is not reversed into a setback for the climate.



3. Measurement and certification of methane emissions

As policies are typically formulated using quantitative targets, the slow commitment to limiting methane emissions may be partly explained by the difficulty of quantifying such emissions. While numerous monitoring technologies exist,[24,29,30,31] no individual technology can perform quantitative assessment on a continuous basis with the correct resolution for all emissions scenarios. Emissions may be very large or tiny, at ground level or at a height, continuous or occasional, accidental or programmed, inherent (slip) or fugitive. Figure 3 gives a schematic representation of possible sources of methane emissions in industrial production and the technologies that may provide a qualitative or quantitative assessment of these emissions.

Some existing technologies can measure methane concentrations precisely and continuously. These can be quantitative if the sensor is used in a controlled system (for example a closed conduit) where the sensor measures the methane concentration of a representative sample. In Figure 3, point (1) is a controlled system: it may be the stack of an engine or a flare. If the gas is well-mixed at the point of measurement, the concentration measured by a sensor can be taken as representative of the whole stream. If the total flowrate of the stream exiting the system is known, it is easy to calculate the flowrate of methane that slips out.

However, quantification becomes much more complex if the measurement is taken in an open space, where the effects of wind direction and speed can bias the methane concentration measurements. Quantification of fugitive emissions is a typical example. In this case, it is still possible to measure the concentration in a sample, for example using handheld devices (Figure 3 point (2)) or perimeter sensors (point (4)), but the

Figure 3: Overview of sources of methane emissions from industrial production and applicable monitoring technologies. Image created using assets from freepik.com.

concentration measurements are only qualitative: they can tell if there is a leak, but not the extent of the problem. In a practical example, a perimeter sensor (point (4)) directly sampling at a small leak may measure a much greater methane concentration than a drone sampling air (point (5)) above a large leak on a windy day, when the wind dilutes the sample.

Various techniques to estimate the extent of dilution are available. [29,30,31] Tracer gas techniques are often used for ground-level measurements at a distance (point(3)), and flux measurements with drones or helicopters are used to measure at a height (point (5)).[32]

Not all quantitative measurements are high-quality: in a recent report by the European Gas Research Group, 13 different companies measured the methane emissions around the same section of the natural gas grid in Spain.[33] Only three of the companies were able to take measurements with absolute average errors below 50% (as shown on slides 11-13 of the reference).[33]

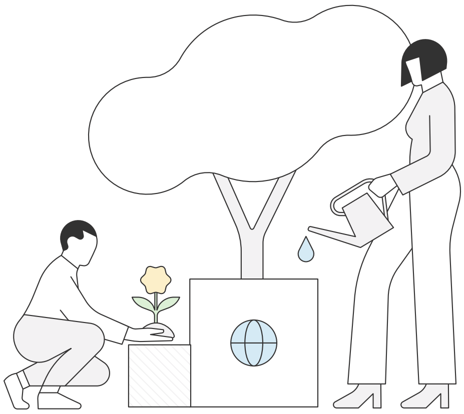
Measurement programs are also being conducted on ships: for example, the FUgitive Methane Emissions from Ships (FUMES) project compares emissions from LNG-fueled ships measured using in-stack continuous emissions monitoring, drones, and helicopters.[18,34] These technologies are, however, not suited or too expensive for continuous quantitative monitoring.

Satellite measurement of methane leakage is another technology of interest, with some projects already in operation today. More satellite measurements of methane have been scheduled for late 2023 as part of the MethaneSAT program.[34] This program will not be able to detect small point sources but is expected to be able to measure emissions from about 80% of global oil and gas production, an industry that today emits more than 80 million tonnes of methane per year.[35] The current focus of the program is not on smaller emitters, but an expansion of the target to agricultural system is being considered.

Even for industrial operations that commit to voluntary reductions of their methane emissions, the practice is to run campaigns of quantitative monitoring. The frequency of campaigns and representativeness of the operations during the measurement campaign therefore become critical parameters, and extracting reliable conclusions about the extent of an asset's emissions is often a problem.

Certification standards for methane emissions are also appearing on the market. The most complete of these, such as the MiQ program,[36] certify the quality of an asset's operations in terms of methane emissions through a combination of emissions monitoring and a thorough review of plant operations. These reviews include assessment of equipment, training of employees, monitoring frequency, corrective and preventive measures, and implementation of lessons learned. MiQ can already offer a certification standard for LNG ships (LNG Standard under MI & in Annex C).[37]

Certification of compliance where regulations exist, or on a voluntary basis where regulation is still not in place, could help to assure the desired low GHG emissions intensity of biofuels from biogas.



4. Typical sources of methane emissions in the value chain for biofuels from biogas

Thorough reviews on methane emissions are available for several steps of the value chain. Here we report the result of our consolidation work based on literature reviews and interviews with experts.

Our analysis starts with biogas production. A recent study by the Technical University of Denmark (DTU) and Rambøll for the Danish Energy Agency measured overall methane emissions at 60 Danish biogas plants and calculated their statistical relevance.[31]

Differences in plant layout and final product add some uncertainties to the study. All plants included biomass handling (schematically shown in Figure 4, element (1)), anaerobic digestion (2), and digestate handling (3) at the site. Methane emissions from livestock housing (barns) may bias the plant's inventory if they are located nearby. Similarly, if the biogas plant is close to the fields receiving the digestate, emissions of methane from digestate storage and spreading may also be included.

Some of the sites have an electrical power generator (4) and others an upgrading/compression section (5), but few include both at the same site. Plants that upgrade biogas to bio-methane also include a compression section (8) to prepare the gas for injection into the natural gas network (9). Elements (1)-(9) are present in typical biogas plants and can release emissions captured by the measurement campaign conducted by Gudmundsson et al.[31]

Figure 4: Overview of the value chain of biofuels (bio-methane and bio-methanol) from biogas. Green lines show processes where methane emissions can occur. Use of bio-methanol per se (blue lines) is not associated with methane emissions but may entail methane emissions in the biogas manufacturing section, as well as some emissions of hydrogen. Pink lines show processes where hydrogen emissions may occur. Gray boxes represent aggregated emissions.

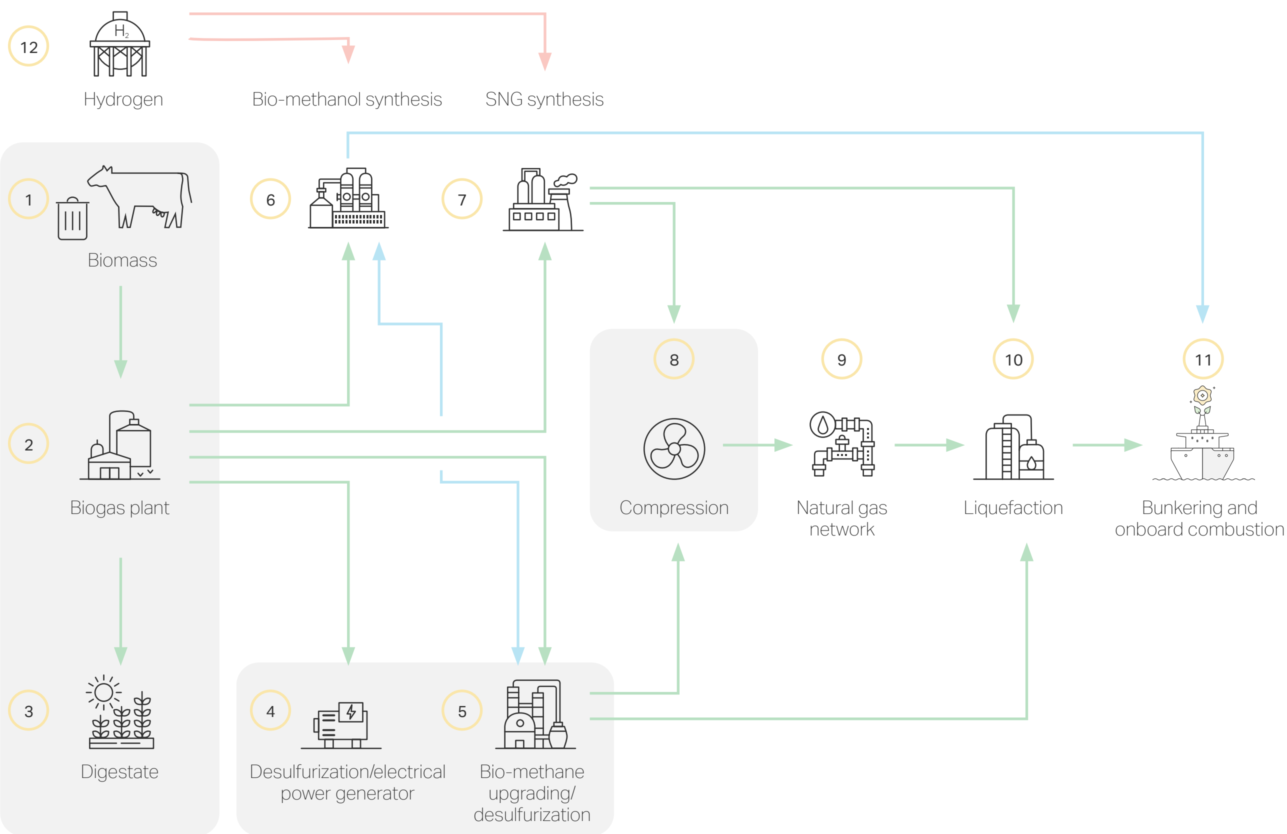
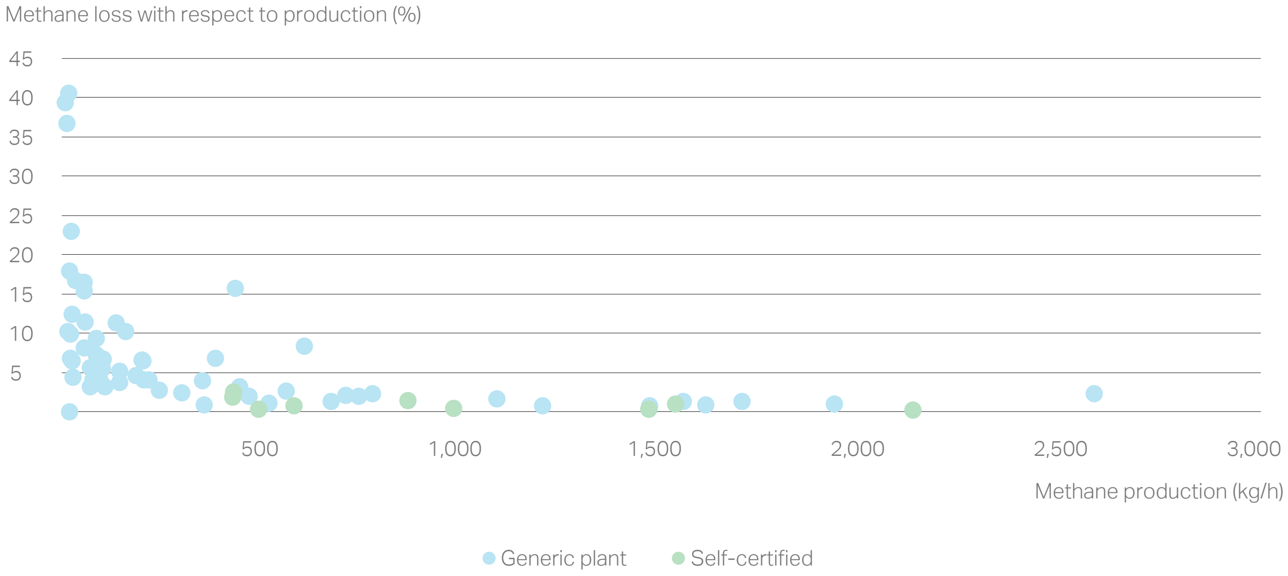


Figure 5: Methane loss from Danish biogas production units. Data from shared production units, individual plants on farms, wastewater treatment plants, industrial plants (all classified under "generic plant", blue circles) compared to data from self-certified plants (green circles). Figure adapted with permission from a study by DTU and Rambøll for the Danish Energy Agency.[31]



An overview of the methane emissions results collected in the DTU-Rambøll study[31] is shown in Figure 5. The emissions for all plants, as a weighted average of methane produced, was 2.5% by volume of the total methane production.[31] The best performers in the study emitted less than 1% of their methane production as fugitive emissions. However, small biogas plants and wastewater treatment plants were associated with very high methane emissions, in the range of 5%-10%. In a few cases, emissions equal to a whopping 35-40% of the total production were measured.

A review of German biogas plants by Liebetrau et al found that a methane loss of 2.5% with respect to methane production was the upper range of plants with covered and tight digestate plants.[29] This figure was calculated from 5 gCH_4/kWh_{el} and applying an energy conversion efficiency to electricity production of 35%. However, the study also found that methane loss could be five times as high as this if no precautions were taken regarding digestate storage. The importance of methane emissions in the biogas manufacturing process is recognized by the EBA, which also suggests a value of 2.5% methane loss as a European average.[24,38]

Targeted efforts to reduce methane emissions from biogas plants have already proven successful.[29,31] Figure 5 compares methane emissions of generic plants to plants undergoing self-certification programs, clearly showing that a focused effort to reduce methane emissions produces strong results.

The full value chain to produce biogas-based biofuels for shipping includes further steps (10)-(12), as shown in Figure 4. Liquefaction of biomethane may be carried out in connection with the upgrader or by pulling methane from the natural gas network. Similarly, manufacturing of bio-methanol is also foreseen to depend on aggregated biogas or bio-methane sources. Neither liquefaction nor bio-methanol manufacture is commonly associated with biogas plants today, and these processes were not included in the published surveys that we reviewed.[24,29,31] An assessment of the emissions from these sources is given in Sections 4.2-4.7 of this report.

4.1 Biogas and bio-methane manufacturing

The overall average of methane loss of 2.5% with respect to production found by DTU and Rambøll in their survey[31] covers all the areas shown in gray in Figure 4. Specifically, this value aggregates the methane losses connected with:

- biomass management, anaerobic digestion, and digestate management (hereafter 'biogas manufacturing', (Figure 4, items (1), (2), and (3))
- electrical power generators and/or biogas upgrading (Figure 4, items (4) and (5))
- compression prior to bio-methane injection into the natural gas network (Figure 4, item (8))

Of these processes, biogas manufacturing is present in all biofuel manufacturing layouts considered in our project, while electrical power generation is mostly not present in biofuel manufacturing layouts. Upgrading and compression may be decentralized with respect to biogas production, depending upon the plant layout.

In the upcoming subsections, we review the sources and scale of methane emissions at different steps in these manufacturing processes, as well as opportunities for emissions reduction. Where relevant, we also comment on how we accounted for methane emissions during a given step as part of our overall estimates.

4.1.1 Biogas manufacturing

Biomass management

Biomass suitable for anaerobic digestion includes animal manure, agricultural residues, food waste including industrial waste from food and beverage production, wastewater, and more — anything organic that can naturally rot. Anaerobic digestion is, in fact, an enhancement of the natural rotting process under controlled conditions. The same biomass rotting in uncontrolled conditions releases (bio-)methane into the atmosphere, with grave consequences for the climate.

Waste rotting is estimated to be one of the largest sources of methane emissions: the IEA and the United Nations Environment Programme (UNEP) put the amount of methane released from waste (solid and wastewater) globally at over 73 million tonnes.[39,40] This figure corresponds to more than 50% of methane released from anthropogenic activities associated with the entire energy sector, which accounts for around 130 million tonnes of methane emissions. Emissions from waste are mostly associated with absent or insufficient waste management practices, such as dumping. Avoidance of all methane emissions from waste by 2030 would save 0.05°C of warming by 2040-2070.[41]

A good portion of the biomass currently left to rot could instead be processed into biogas under controlled conditions. Just processing all wastewater in this way could reduce methane emissions by 30 million tonnes every year. The potential of biogas for slashing emissions from rotting waste is recognized by certain regulations. For example, the guidelines for calculating emissions intensity of biogas-based processes in the EU Renewable Energy Directive (RED II) allow inclusion of negative emissions for emissions saved from raw manure management.[42]

When speaking about methane emissions with representatives of the biogas industry, we have occasionally met the opinion that, since biogenic waste rots into methane as a consequence of natural decomposition, a biogas plant will always emit less methane than nature would if waste were left untreated. However, this position does not consider that methane production from rotting depends upon many variables, including temperature, time,[43,44] substrate status,[45] and availability of oxygen and sulfur[46] — all conditions that are optimized for methane production in an industrial plant, but not in nature. Therefore, while biogas plants render a useful service in eliminating waste accumulation problems and the associated methane emissions from uncontrolled rotting, it is important to also focus on reducing methane emissions from biogas plants, so that the full climate benefits of this process can be harvested.

Anaerobic digestion

The main element of the biogas plant is the anaerobic digester: a closed container filled with an aqueous phase containing bacteria and continuously fed with biomass. The reactor does not contain oxygen, and the bacteria digest the biomass in anaerobic conditions, producing biogas that is then removed from the reactor. The biomass can contain several large chemical structures (such as sugars, fats, carbohydrates, cellulose, hemicellulose, and lignin) mostly made up of carbon, hydrogen, and oxygen. The resulting biogas is approximately 50-60% methane and 50-40% CO_2, plus small amounts of hydrogen, nitrogen, hydrogen sulfide, and ammonia.

Correct design and operation of a biogas plant requires considerable experience. A reactor operates with three phases (solid, liquid, and gaseous), and it must be continuously stirred to ensure good contact between the biomass and the bacteria. Modern plants comprise multiple reactors in series to maximize the methane yield and minimize operational costs by reducing sizes, residence times, and heat demand. Biomass is continuously added, gas is continuously withdrawn and stored in containers with expandable roofs, and digestate is moved between equipment to optimize heat integration and extract as much methane as possible.

Insufficient equipment selection and operations may cause methane emissions from multiple sources. Liebetrau et al,[29] Reinelt et al,[47] Gudmundsson et al,[31] and the EBA[24] have all compiled information on typical leakage points in biogas plants based on literature reviews, direct inputs, and/or own measurements. Improper selection or maintenance of equipment can lead to leakages at almost all components of a plant: connection points (between pipes, reactor elements, valves), at the reactors' membrane roofs, in storage tanks, and in blowers and compressors. These studies also found numerous perfectly avoidable emission points, such as covers that were not put in place, damaged concrete containers, or loss of tight connection between concrete and plastic tubes.

Digestate management

Digestate is a nutrient-rich material generated as a residue of the anaerobic digestion process. Depending on the feedstock and applicable legislation, digestate is often used as a soil amendment. Digestate can partly or wholly replace synthetic fertilizers, a practice that is both economical and improves the WTW GHG emissions of a biogas-based biofuel. Digestate is typically stored temporarily at the biogas plant before it is dispatched to a farm. Digestate may also be stored at the farm for some time, since the application of digestate on soils must follow agricultural cycles.[29]

Digestate contains residual methane and, if improperly managed, is one of the largest sources of emissions in a biogas plant. [29,48] Methane emissions from digestate at the biogas plant can be controlled by:

- maximizing digestion of the organic materials at the biogas plant [43,44]
- fast-cooling digestate to below 15°C to slow down methanogenesis
- collecting any gas developed in the storage tanks

Storage of digestate at the agricultural fields must follow the same precautions.

4.1.2 Electrical power generators

The most common use of biogas worldwide is combustion in electrical power generators, mostly for combined heat and power applications.[49] Like LNG engines, electrical power generators are prone to methane slip. Liebetrau et al have reported the average slip of a biogas engine as 1.9%,[29] while the review of Danish plants by Gudmundsson et al indicates an average slip of 1.4%.[31,29] These numbers refer to electrical power generators without thermal post-combustion.

Methane emissions from electrical power generators can be eliminated by means of thermal oxidation of residual methane.[29] Liebetrau et al also show that for electrical power generators with thermal post-combustion, methane slip can be reduced to nil.[29] Some countries, such as Germany and The Netherlands, enforce limits on methane emissions from electrical power generators (1.3 and 1.2 g/m^3, respectively),[24,29] but unfortunately such limits are not globally imposed.

Emissions from electrical power generators are a part of the overall assessments conducted by Liebetrau et al and Gudmundsson et al, contributing to a reported average methane loss of 2.5% with respect to production.[29,31] However, we generally do not foresee widespread presence of electrical power generators in biofuel plants, except in cases where the plant is forced to generate its own electricity due to lack of access to other renewable electrical power. Considering the low efficiency of electrical power generation, our hypothesis is that other forms of renewable energy will be preferred.

As we will see in Sections 4.1.3 and 4.1.4, power generation and upgrading and compression contribute similar levels of methane emissions. We have not attempted to isolate the contributions of emissions from electrical power generation from the aggregated methane loss of 2.5%.

4.1.3 Biogas upgrading

Removal of CO_2 and other impurities from biogas generates bio-methane, which can be used as a replacement for natural gas in the natural gas network. Upgrading technologies commonly used in the industry include membrane technology, pressure swing absorption (PSA), water scrubbing, and amine scrubbing. Other technologies, like potassium carbonate scrubbing, are on the rise. Large biogas plants often use a water or chemical scrubber. According to statistics compiled in 2020 by IEA Group 37, water scrubbing and membrane separation were each used in nearly 30% of the 606 plants surveyed.[50] Chemical scrubbing was used in 17% of the plants and PSA in 13%. The remaining plants in the report either used other technologies or did not have available data.

CO_2 separation is never perfect, and some methane leaves with the CO_2 stream as methane slip. A study by Kvist and Aryal of typical methane losses in commercial plants reported that methane slip accounted for 0.04% of the entire methane production for plants using amine scrubbers, 1.97% for water scrubbing, and 0.56% for membrane upgrading.[51]

The overall cost of upgrading depends on both the availability of integration options (e.g., heat or compression) and the methane slip at the upgrader. Methane slip causes lost earnings due to wasted product and creates an important point source of methane emissions if regulations allow venting.

Methane emissions from upgrader slip can be significantly reduced by thermal oxidation, but this is not applied if regulations are not in force. Methane losses from upgraders are currently regulated in Germany, France,[24] and Denmark.[25] The emissions limit in Germany is 0.2% in the off-gas (required thermal post-combustion). In France and Denmark, the limit is on the slip (loss with respect to production) with a value of around 1% (0.5% in France for large plants). Since available technologies can slash emissions to far below these thresholds, we expect and hope that more restrictive regulations will be broadly enforced.

For future plants, we expect that losses at the upgrader may be greatly reduced by selection of upgrading technologies which will keep the loss of valuable product to the minimum. Further, we expect regulations on this point emissions to tighten, since lower emissions are easily achievable.

To ensure that this optimistic prognosis does not unduly bias our emissions intensity calculation for existing commercial plants, we have not subtracted losses from the upgrader from the 2.5% average methane losses established in Section 4.1. This approach somewhat disfavors processes that do not require upgrading (SNG and bio-methanol manufacture if they are attached directly to the biogas plants). However, considering that these processes are not yet commercially implemented and that the layout is still uncertain, and the nature of our study is qualitative, we consider the error acceptable.

4.1.4 Compression

After purification in the upgrader, bio-methane must be compressed before it is injected into the natural gas network. The required pressure depends upon the distance to and pressure at the available point of injection. Compression is an integral part of membrane upgrading. For scrubbing technologies, whether they are water- or chemical-based, bio-methane must be compressed in an additional unit.

Compressors have important methane losses. For our subsequent analyses, we include a loss of 0.4% of the bio-methane at the compression step. This number is a back-of-the-envelope calculation obtained from EPA data for the US natural gas grid as the ratio between the total annual leakage from compressors (86 billion cubic feet)[52,53] and the total annual natural gas consumption for the year 2005 (22 trillion cubic feet).[54]

Compressor losses may bias the average 2.5% loss from biogas production if they are within or close to the biogas plant's footprint. This depends upon the plant layout and location with respect to the chosen injection point into the natural gas grid. Due to this uncertainty, we have not attempted to disaggregate the contribution of compression from the overall 2.5% methane losses during biogas production.

4.1.5 Biogas desulfurization

As described in detail in our companion report on energy demand for emissions reduction compliance, desulfurization during commercial bio-methane production does not require special consideration with respect to methane losses. This is because desulfurization in this context is carried out on the CO_2-rich stream from the upgrader, and thus any fugitive emissions are mostly CO_2. This is not so for electrical power generation, where desulfurization is carried out on the biogas stream, or for catalytic synthesis of methanol and SNG.

Methane emissions from in-situ desulfurization technologies are part of the methane emissions at the anaerobic digester. We were unable to find specific emissions data for the most common ex-situ desulfurization processes, i.e., biological desulfurization or adsorption by activated carbon. For the purposes of this report, we have therefore considered a methane loss during desulfurization equal to 0.1% of the methane in the stream, in line with other post-processing technologies.

4.2 Bio-methanol synthesis

Synthesis of methanol from reforming of natural gas is an established industrial process conducted at high pressure in catalytic reactors. Synthesis of bio-methanol from biogas reforming is expected to use some of the same steps, but it may also introduce some new technologies such as e-REACT™. Our accompanying study on energy demand for emissions reduction compliance contains additional information on bio-methanol synthesis from biogas. As this process is not yet commercial, there are no real-world plant data available to assess typical emissions from bio-methanol synthesis from biogas reforming.

Instead, we sourced information about methane emissions during currently commercial bio-methanol synthesis processes. Licensors of methanol manufacturing plants indicate a general methane loss of below 0.1% with respect to the processed methane from control valves, and below 0.1% through seals in the gas compressor. As a standard, these leakages are collected by process vents and sent to flare, where residual methane is oxidized. Considering that the methane removal efficiency of flares is not 100%, for the purposes of this study we have considered a total methane loss from the process of 0.1% of the input methane.

4.3 CO_2 conversion to bio-methane (SNG production)

Methane can be produced from CO_2 using either catalytic synthesis via the Sabatier reaction, or by biological synthesis by methanogenic microorganisms. Methane produced in this way is also known as synthetic natural gas or SNG. The two SNG production pathways are compared in more detail in our companion report on energy demand for emissions reduction compliance.

For the purposes of estimating methane emissions during this process, since we have no available data from operating Sabatier or biological plants, we have used the same emissions level as for methanol synthesis (0.1% of the total input methane).

4.4 Natural gas network and storage

Our companion report on insights into the value chain describes various scenarios for aggregation of bio-methane and biogas via pipeline networks. Biogas aggregation is not currently practiced extensively as this requires a dedicated network which does not yet exist, while bio-methane can be aggregated using existing networks of natural gas pipelines. Therefore, by reviewing the current methane emissions from representative existing natural gas networks, we can gain insight into the level of methane emissions expected during aggregation of bio-methane using the same natural gas systems.

Knowledge of methane emissions from the natural gas network is already abundant. Marcogaz, the technical association of the European gas industry, estimates a loss of 0.05-0.08% with respect to the transported methane from the European transmission system (the high-pressure system of pipelines that transports methane over long distances).[55] Additionally, 0.08–0.21% of methane is lost from the distribution grid (the low- to medium-pressure system of pipelines that reaches households and other local consumers).[55] The total leakage from European gas grids therefore totals around 0.13-0.29%.[55]

The Danish Gas Technology Center has reported estimates for the Danish natural gas grid.[48] The reported methane losses in Denmark for the year 2019 were 0.01-0.02% for transmission and 0.04% for distribution.[56] Regulation may be the reason for lower methane emissions from the Danish network compared to the European averages reported by Marcogaz. In Denmark, the cost of remediation work is billed to the end users, a practice that other European countries do not allow. If end users do not directly pay for grid ameliorations, the transmission system operator has a reduced ability to invest in emissions mitigation, meaning that maintenance operations are prioritized together with other investments.

The total GHG footprint of natural gas used in Europe is higher for gas piped from Russia, Ukraine, and Belarus due to the length of pipelines (over 4,000–5,000 km) and, in some cases, aged installations. For these supply chains, an additional methane loss of roughly 0.5% should be accounted for.[57]

Natural gas is today stored in large underground storage facilities. Methane leakage from natural gas storage facilities in Europe has been reported to be 0.02% by Marcogaz.[55] This number does not distinguish between different types of storage facilities.

If a biofuel value chain includes transport of bio-methane via pipelines, then methane losses will be the same as for natural gas transported using the same networks. Therefore, when analyzing biofuel manufacturing scenarios that include transport via the natural gas grid, we have used a value of 0.15% bio-methane loss with respect to transported bio-methane.

4.5 Methane liquefaction and transport

Like natural gas and fossil methane, effective bunkering of bio-methane requires liquefaction to increase fuel density. The process of bio-methane liquefaction is identical to natural gas liquefaction except for plant capacity, which will be significantly smaller for biofuels.

In the absence of data from bio-methane plants, we used estimates for natural gas plants to guide our estimates of potential methane emissions from bio-methane liquefaction. An assessment of methane emissions in the LNG value chain by Equinor reported the company's own methane losses from a reference liquefaction plant in Hammerfest (Snøhvit) as 0.01% of produced methane versus a European average of approximately 0.8%.[58]

LNG transport is known to have emissions of boil-off gas (BOG), which is generated when LNG heats up in tanks. When the carrier needs propulsion, BOG is used as fuel. When the carrier does not need propulsion, BOG can be re-liquified. However, reliquefaction consumes large amounts of electricity, and in practice operators may choose to simply vent the BOG. This is true both for transport in ships[59] and in trucks.[60] Equinor reports a range of methane losses for LNG transport between 0.02 and 0.04%.[58] We could not confirm whether this range includes emissions due to venting of BOG.

The IEA Methane Tracker 2023 indicates that collective methane losses during LNG manufacturing (methane processing and liquefaction) and transport are in the range of 0.1% of the LNG consumed.[61] We assume that the difference between the IEA value and the Equinor finding[58] is in the production losses and have used an overall loss of 0.1% for methane production and transport in our energy and material balances.

4.6 Storage, bunkering, and onboard combustion

LBM is completely interchangeable with LNG and may be used as bunker fuel in hundreds of ships already in operation. Our report on insights into the value chain gives further details on the current status of LNG as a marine fuel, which gives an indication of the potential for LBM consumption in the industry.

The use of LNG as a marine fuel is controversial due to onboard methane emissions. The International Council on Clean Transportation has studied the WTW GHG emissions of LNG propulsion in shipping and concluded that due to slip and fugitive methane emissions, there is no benefit in using LNG over other fossil fuels.[62] The same report further concluded that LNG can make matters worse in ships with highly polluting engines.[62] The issue of methane emissions from ships was also recently recognized by the Sea-LNG coalition, which called on the IMO for specific regulation of the issue.[19] If LBM sees widespread adoption as a marine fuel, it will confront similar challenges regarding onboard methane emissions.

A previous publication from the MMMCZCS examined the issue of onboard methane slip in some representative LNG-fueled engines and vessels.[16] The study found theoretical slip in the range of 1.1-3.3% for ships with high-pressure two-stroke and low-pressure four-stroke main engines. Methane slip from “best in class” engines was found to be 0.2%. However, these slip-free engines are not the technology of choice in all ships. Furthermore, these engines are currently only supplied as main engines while auxiliaries use low-pressure four-stroke technology with approximately 3.3% methane slip. As a consequence, the current industry average for methane loss during a voyage is calculated as 2.2% of the bunkered methane.[16]

Without design changes or addition of emissions reduction or mitigation solutions, we can assume that similar levels of methane slip will be present in vessel engines operating on LBM. For our energy and material balances, we therefore set the value of onboard methane emissions from LBM use at 2.2% of the bunkered fuel.

In the future, onboard methane emissions may fall below 1% thanks to several factors, including:

- Progressive replacement of low-performance engines with high-performance designs
- Implementation of after-treatment technologies for methane reduction now on their way to commercialization[16]
- Innovations aiming to eliminate methane slip altogether[63]
- Replacement of auxiliary engines, which today are mainly high-emitting four-stroke designs, with onboard batteries and shore power[64]

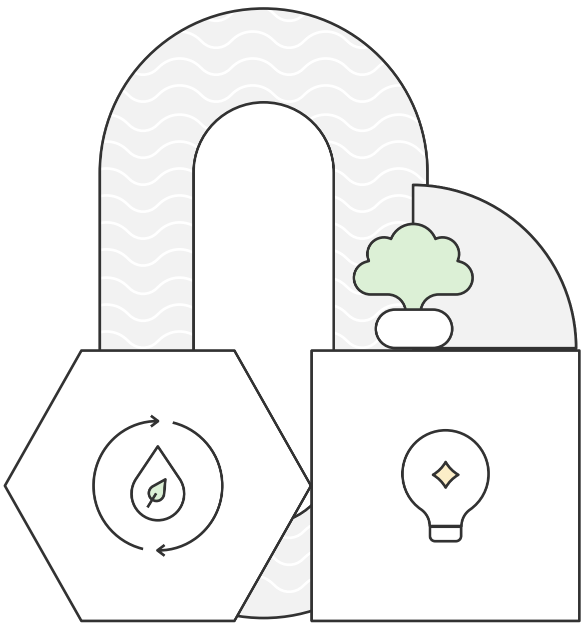
4.7 Hydrogen

Hydrogen does not have a direct global warming effect, but its presence in the atmosphere perturbs the methane cycle and therefore has an indirect effect on climate.[65] The GWP of hydrogen has not been the target of much study to date. However, due to hydrogen’s anticipated significance in future energy systems, some expressions of concern have recently been floated. For example, in studying the atmospheric implications of increased hydrogen use, Warwick et al have assessed the total GWP100 of hydrogen as being in the range of 6.4–15.3.[66]

Hydrogen is likely to play a role in the value chain of biogas-based biofuels, as it is used especially in the production of bio-methanol from biogas and in SNG production (see Figure 2). However, due to a lack of available information, we have not included an estimate of hydrogen’s impact in our overall assessment for the purposes of this series of reports. The climate implications of hydrogen need to be followed up on in the future to ensure that biogas-based biofuels achieve the expected GHG emissions reductions.

4.8 Summary of emissions along the value chain

Our estimates of methane emissions along the biogas-based biofuels value chain, based on this review, are graphically summarized in Figure 6. The figure shows seven selected biofuel production pathways: four for LBM production (Pathways 1a, 1b, 2, and 3) and three for AA-grade bio-methanol production (Pathways 6a, 6b, and 7). We chose to exclude two pathways for production of fuel-grade bio-methanol (Pathways 4 and 5) for the purposes of the current report. All nine pathways are more thoroughly described in our companion reports on energy demand for emissions reduction compliance and WTW GHG emissions.



Briefly, **Pathway 1a** (standard LBM) is a commercial LBM manufacturing pathway comprising:

1. Anaerobic digestion,
2. Biogas upgrading with CO_2 separation. Release of CO_2 to the atmosphere,
3. Liquefaction,
4. Transport and bunkering, and
5. Onboard combustion.

Pathway 1b (standard LBM with CCS) is a modification of Pathway 1a that includes CO_2 capture and storage (CCS).

Pathway 2 (SNG1) does not include biogas upgrading. Instead, biogas is reacted with green hydrogen in a catalytic process to obtain more methane in the form of SNG.

Pathway 3 (SNG2) is as Pathway 2, but with SNG production via a biological process rather than catalytic.

Pathway 6a (AA BioMeOH1) is based on traditional reforming to produce bio-methanol, comprising:

1. Anaerobic digestion,
2. Traditional reforming,
3. Reaction of reformed biogas with green hydrogen into bio-methanol,
4. Release of excess CO_2 and other gases to the atmosphere,
5. Transport and bunkering, and
6. Onboard combustion.

Pathway 6b (AA BioMeOH1 with CCS) is a modification of Pathway 6a that includes CCS.

Pathway 7 (AA BioMeOH2) produces bio-methanol from biogas using an electrical reformer, enabling complete conversion of CO_2 into methanol (no residual CO_2).

Table 1: Summary of selected biofuel production pathways.

<table>
<tr><th>No.</th><th>Description</th><th>Anaerobic digestion</th><th>CO_2 separation</th><th>Catalytic SNG</th><th>Biological SNG</th><th>CCS</th><th>Standard SMR/ MeOH</th><th>eREACT™ /MeOH</th><th>MeOH Distillation</th><th>Product</th></tr>
<tr><td>1a</td><td>Standard LBM</td><td>◆</td><td>◆</td><td></td><td></td><td></td><td></td><td></td><td></td><td rowspan="4">LBM</td></tr>
<tr><td>1b</td><td>Standard LBM w. CCS</td><td>◆</td><td>◆</td><td></td><td></td><td>◆</td><td></td><td></td><td></td></tr>
<tr><td>2</td><td>SNG1</td><td>◆</td><td></td><td>◆</td><td></td><td></td><td></td><td></td><td></td></tr>
<tr><td>3</td><td>SNG2</td><td>◆</td><td>◆</td><td></td><td>◆</td><td></td><td></td><td></td><td></td></tr>
<tr><td>6a</td><td>AA BioMeOH1</td><td>◆</td><td></td><td></td><td></td><td></td><td>◆</td><td></td><td>◆</td><td rowspan="3">AA bio-methanol</td></tr>
<tr><td>6b</td><td>AA BioMeOH1 w. CCS</td><td>◆</td><td>◆</td><td></td><td></td><td>◆</td><td>◆</td><td></td><td>◆</td></tr>
<tr><td>7</td><td>AA BioMeOH2</td><td>◆</td><td></td><td></td><td></td><td></td><td></td><td>◆</td><td>◆</td></tr>
</table>

LBM = liquified bio-methane, CCS = carbon capture and storage, SNG = synthetic natural gas, FG BioMeOH = fuel-grade bio-methanol, AA BioMeOH = AA-grade bio-methanol, SMR = steam methane reforming, eREACT = electric SMR.

For each pathway, we have defined the "bunkered methane equivalent" as the energy in the bunker fuel divided by the lower calorific value of methane. The "bunkered methane equivalent" allows us to compare methane losses of value chains that supply biogas-based LBM and bio-methanol via various pathways.

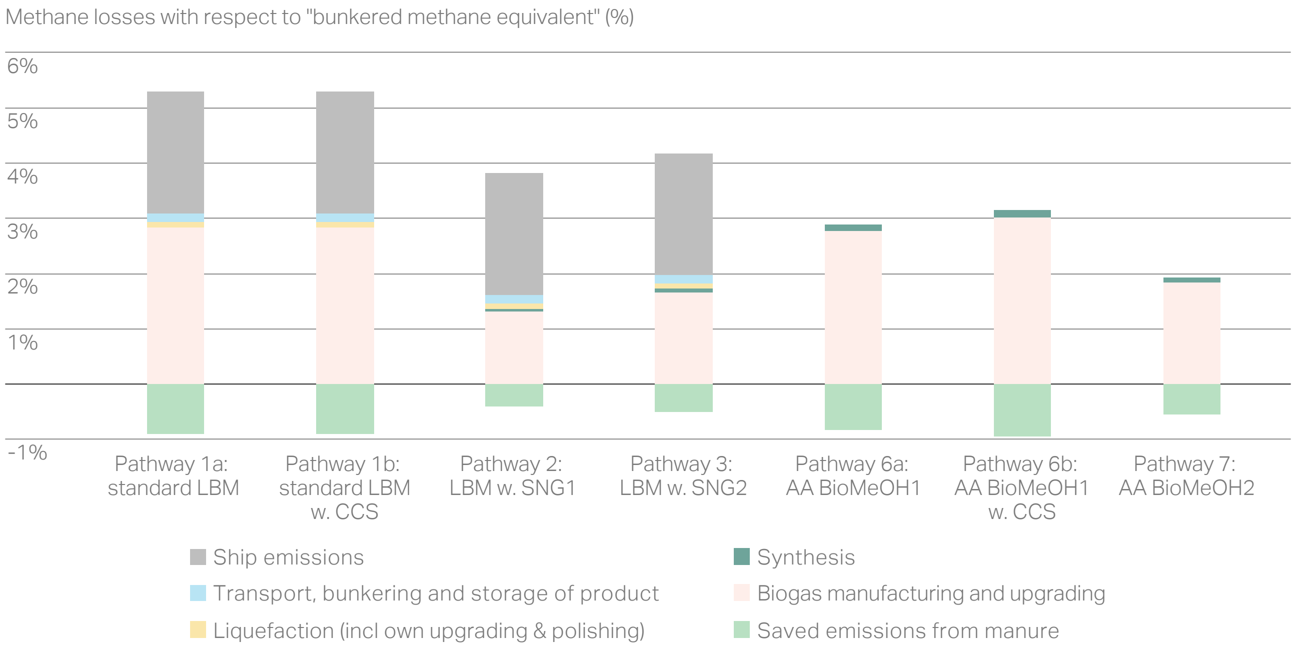
For LBM, Figure 6 shows that the largest contributions to methane emissions come from the biogas/bio-methane manufacturing (peach bar segments) and on board the ship (gray bar segments). The total methane losses are in the range of 5-6% for Pathway 1 (the established commercial pathway) and a little less for the SNG pathways (around 4%).

For bio-methanol, there are no onboard methane emissions. The consumption of biomass is higher for processes reliant on traditional reforming technology (Pathways 6a and 6b), which have methane losses in the range of 3%. The lowest losses (approximately 2%) are achieved by Pathway 7, which converts all of the biogenic CO_2 into bio-methanol by means of an electric reformer.

Figure 6 also shows the "methane savings" (green bar segments), which are the credits earned for treating manure (see the subsection on 'biomass management' in Section 4.1.1). Interestingly, the methane savings from manure follow the consumption of biogas and are therefore higher in the pathways that do not add hydrogen.

We have not been able to find published reports analysing similar value chains to carry out a validation of our results. As a qualitative comparison, Bakkaloglu et al analyzed total methane emissions distribution from several published studies for bio-methane and biogas supply chains, excluding methane liquefaction, transport, bunkering, and onboard combustion, but including feedstock handling.[48] These authors found maximum emissions in the range of 20% and mean emissions in the range of 5-6%, in broad qualitative agreement with our results for Pathway 1.

Figure 6: Methane losses as a percentage of the "bunkered methane equivalent" for seven biogas-based biofuel production pathways.



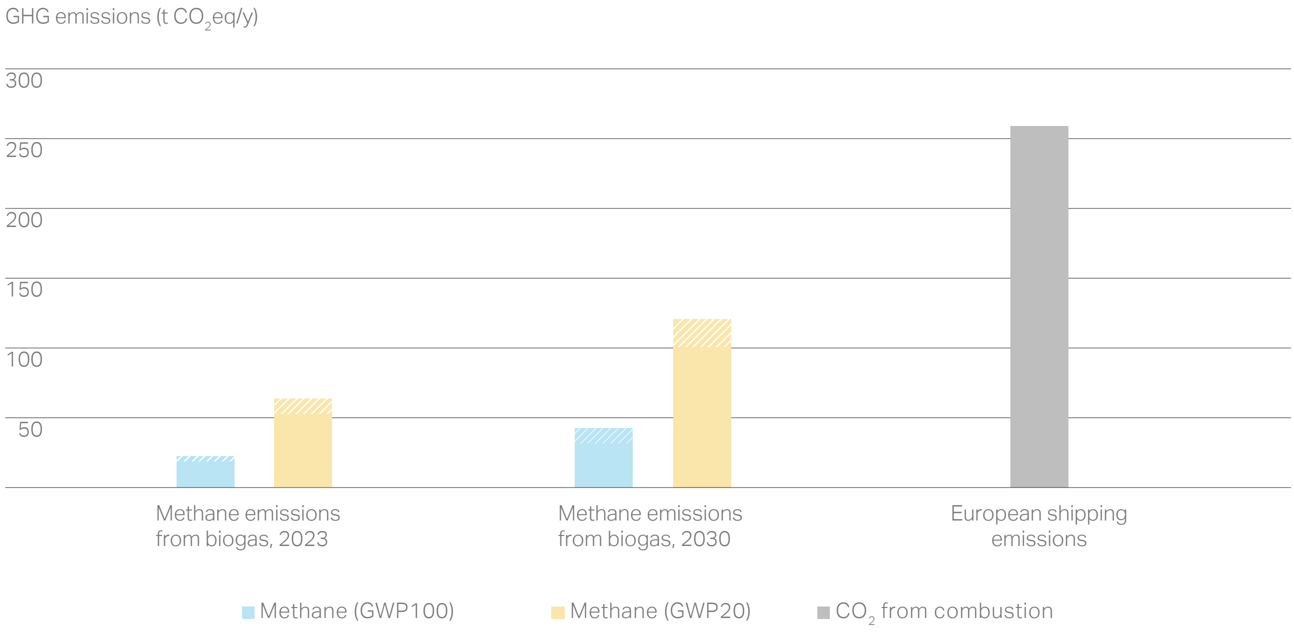
5. Perspectives for the biogas industry

We use the range identified by Bakkaloglu et al[48] to put into context the effect of the anticipated explosive growth in biogas production on CO_2-equivalent GHG emissions. As described in our companion report on insights into the value chain, interest in biogas is currently high. In Europe alone, the Repower EU proposal indicates an ambition to produce 35 billion cubic meters of bio-methane per year by 2030[67] – equivalent to 25 million tonnes of bio-methane per year. These values represent almost a doubling of 2023 biogas production. Methane losses of 5-6% would amount to 1.2– 1.5 million tonnes of methane emitted per year by 2030.

Figure 7 shows the contribution to climate change of methane emissions caused by 5-6% losses from both current European biogas production and production projected to 2030. We have calculated CO_2-equivalent values for these methane emissions using both GWP100 and GWP20. By 2030, methane emissions from European biogas production may contribute 35-40 million tonnes per year of CO_2-equivalent with GWP100, or 100-120 million tonnes with GWP20. For context, European shipping consumes ~83 million tonnes per year of marine fuel, which yields approximately 260 million tonnes of CO_2 per year.

Therefore, fugitive methane emissions from biogas-based European supply chains may contribute to global warming at a level equivalent to 15-45% of European shipping's operations. While the two sectors are not linked, we hope that this comparison highlights the urgency of regulating the biogas industry now, to ensure that the many new plants use leak-free technology.

Figure 7: Greenhouse gas (GHG) emissions from fugitive and slip (avoidable) methane emissions from current and projected European biogas infrastructure, compared with difficult-to-abate emissions from operation of European shipping. GWP = global warming potential. Compact/dashed colours show emissions with 5% / 6% losses.



6. Effect of methane emissions on the sustainability of biogas-based biofuels

To determine the emissions intensity of biogas-based biofuels, we used the typical methane emissions represented in Figure 6 for energy and material balances and well-to-wake greenhouse gas emissions assessment. Figure 8 shows the total emissions intensities of biofuels produced using the seven pathways described in Section 4.8. Intensities are reported in gCO_2eq per MJ of bunkered fuel, and methane has been accounted for using a GWP100 of 28.

We have grouped emissions contributions, both charges and credits, into the following categories: fugitive emissions, electricity, transport (charges), manure management, heat recovery, CCS, and fertilizer (credit).

Figure 8 shows that, based on typical methane losses and the conventional GWP100 for methane, the emissions intensity of biofuels supplied and used according to these pathways (dark gray continuous line) is in the range of 18 to 28 gCO_2eq/MJ — which is lower than the sustainability threshold defined by RED II (black horizontal line at 31 gCO_2eq/MJ). The pathways that include CCS have negative emissions intensity (-24 and -16 gCO_2eq/MJ for LBM and bio-methanol, respectively) thanks to carbon credits obtained from the capture of biogenic CO_2.

For the sake of comparison, the same value chains with overall methane losses of 50% higher than typical are shown as a continuous red line in Figure 8. Both LBM and bio-methanol from pathways comprising CCS (Pathways 1b and 6b) have negative emissions intensity even with these increased methane losses and would still be efficient in decarbonizing shipping operations. However, LBM generated from pathways without CCS (Pathways 1a, 2, and 3) exceeds the RED II sustainability threshold (for eligibility for FuelEU Compliance) and therefore is not eligible for the purpose of emissions reduction calculations. On the other hand, biogas-based bio-methanol (Pathways 6-7) would still be below the sustainability threshold. However, the emissions intensity for bio-methanol produced without CCS would be high.

If methane emissions are mitigated to achieve tight value chains with "best-in-class" emissions levels, total losses as low as 0.5% may be achievable. We calculated 0.5% as the sum of methane losses from best-in-class methane production and distribution (0.3% from Equinor's value chain, see Section 4.4) and from onboard slip and fugitive emissions (0.2% based on best-in-class main engines and assuming that new auxiliaries are as efficient as main engines and there are no fugitive emissions, see Section 4.6).

With these assumptions, emissions intensity was reduced by 15–30 gCO_2eq/MJ, depending upon the pathway. All biofuel production pathways considered have negative emissions (blue continuous line) and become very attractive from a decarbonization perspective. In particular, CCS pathways (Pathways 1b and 6b) achieve deeply negative emissions intensities of -30 to -50gCO_2eq/MJ.

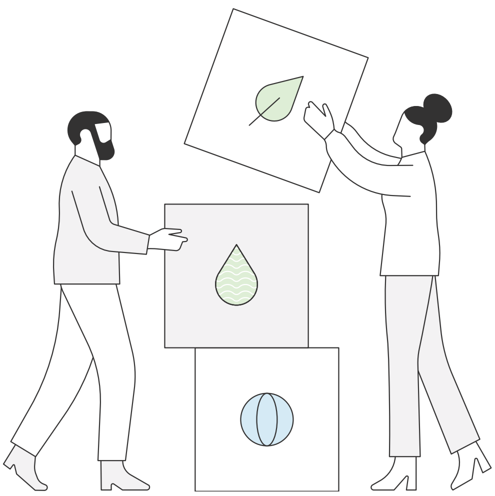
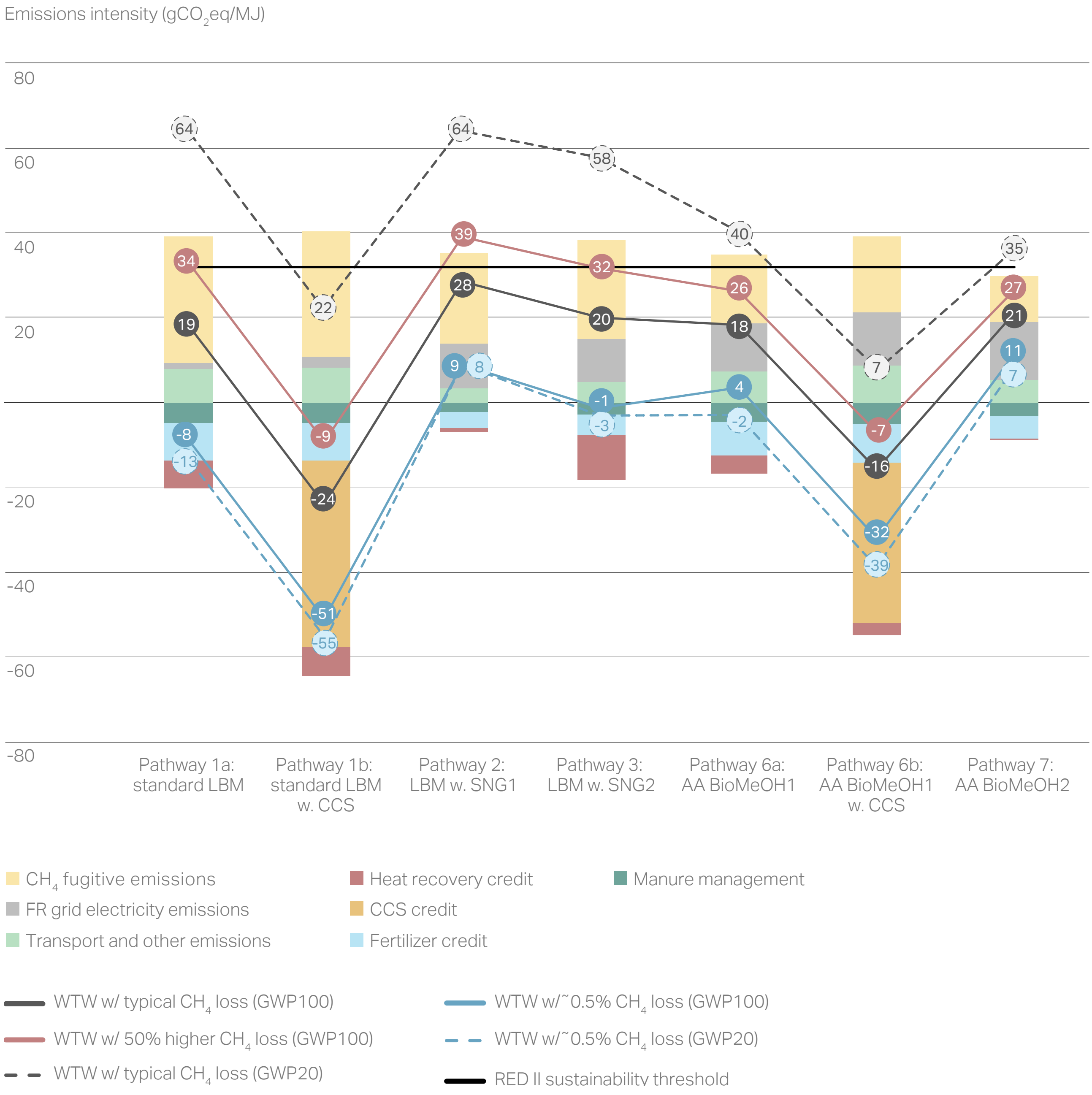


Figure 8: Emissions intensity of selected biogas-based biofuels with various methane emissions levels and global warming potential (GWP) time horizons.



This massive reduction in emissions intensity has important consequences for the emissions reduction potential of a biofuel and therefore on the biofuel's value. In fact, the amount of a given biofuel required to achieve a certain decarbonization target can be reduced by 25% if the WTW emissions intensity of the fuel is reduced from 20 to -10 gCO_2eq/MJ, and by 50% if the emissions intensity is reduced from 20 to -50 gCO_2eq/MJ.

As discussed in our report on energy demand for emissions reduction compliance, the lower the emissions intensity, the more attractive the biofuel. This is because a ship operator then needs less biofuel to comply with emissions reduction targets.

By way of example, we can consider the emissions intensity reduction achievable for Pathway 1a (standard LBM): mitigating typical losses from 5.6% down to

0.5% brings the associated emissions intensity of the pathway from 19 to -8 gCO_2eq/MJ. With reference to Figure 11 in our companion report on energy demand for emissions reduction compliance, such a reduction in emissions intensity allows a shipping operator to achieve the same overall emissions reduction using approximately 25% less biofuel. If CCS were to be implemented on such a value chain (Pathway 1b), the emissions intensity of the biofuel could be as low as -51 gCO_2eq/MJ. In this case, only half the quantity of biofuel would be required to achieve the same emissions reduction as a biofuel with an emissions intensity of 19 gCO_2eq/MJ.

Considering the high cost of biofuels, such reductions in GHG intensity may reduce operating costs. Also, in an emissions reduction pooling scenario, achieving compliance with less biofuel may reduce capital investment if fewer ships require modifications or if modifications are less capital-intensive.

Figure 8 also puts into perspective the importance of emissions reduction in light of the discussion surrounding methane's GWP. As discussed in Chapter 2.1, there is an important scientific debate on how to account for the impact of methane on global warming. If we consider a GWP20 value of 80 for methane, instead of the current GWP100 of 28, the contribution of methane emissions would almost treble. Emissions intensities calculated applying this GWP20 to "typical" methane emissions are shown as a dark gray dashed line in Figure 8. The emissions intensity of LBM produced using Pathway 1a would increase from 19 gCO_2eq/MJ to 64 gCO_2eq/MJ, exceeding the sustainability threshold. A shipping operator committed to the long-term off-take of such a biofuel would therefore not be able to account for the biofuel in their emissions reduction balance.

Finally, the dashed blue line in Figure 8 shows the effect of a change in methane's GWP time horizon on 'tight' value chains with very good control of methane emissions: replacing GWP100 with GWP20 actually has a positive effect, further reducing the total emissions intensity of these biofuels. This is because such tight value chains have a negative methane emissions balance, since the credits (for improved management of manure) are higher than the charges. Increasing the GWP value therefore increases the value of these credits' contribution in a negative direction. Biofuels supplied and used in tight value chains have the additional benefit of de-risking the value chain against possible sharpening of regulatory mandates regarding methane emissions.

7. Conclusion

This study reviews methane emissions across the value chain of biogas-based biofuels for shipping in terms of emissions sources, mitigation opportunities, and regulation. Furthermore, the study quantifies methane losses from the entire value chain and analyses their impact on the emissions intensity of the resulting biofuels.

We have assessed that current "typical" value chains have methane losses in the range of 5-6% (Figure 6), most of which would be preventable through correct engineering design and proper maintenance and operation programs. In a European context, considering the enormous boost that REpowerEU gives to bio-methane production, losses of 5-6% from biogas infrastructure could cause the release of 1.2–1.5 million tonnes of methane per year by 2030. The effect of these emissions on the climate would correspond to that of 15–45% (using GWP100 and GWP20, respectively) of the CO_2 emissions for which European shipping is responsible (Figure 7).

The lessons learned in the fossil sector show that regulations are instrumental in reducing emissions to a minimum. However, we have found that regulation of methane emissions is still somewhat scattered for biogas-based value chains. Thus, we consider tightening of the regulations in the biogas industry as being of the utmost importance and urgency to ensure that new plants coming into operation have incorporated the right technology to be emissions-free.

We have also used the methane emissions estimated in this study to calculate the emissions intensity of biogas-based biofuels for shipping (Figure 8). We found that value chains with typical overall methane losses of 5–6% deliver biofuels that comply with current sustainability criteria and allow acceptable emissions reductions, provided that calculations use a GWP100 value of 28 for methane. However, if methane losses were to increase by 50% over the typical level, LBM would exceed the sustainability threshold.

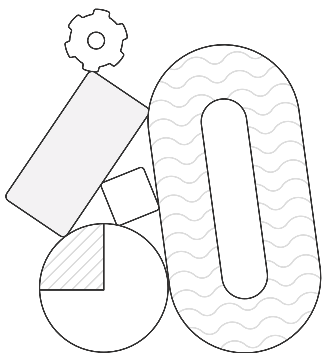
If more conservative opinions were to prevail in the current scientific debate on accounting practices for methane, with emissions intensity instead calculated on the basis of a GWP20 value of 80, value chains with methane losses of 5–6% would deliver biofuels that do not comply with current sustainability criteria (Figure 8).

In this case, shipping operators committed to long-term supply agreements for biofuel value chains affected by typical losses may not be able to use these biofuels.

Fortunately, the technologies required to limit methane emissions to a bare minimum seem to exist. Representatives of the fossil industry state that minimizing overall losses to 0.3% is possible. The biogas industry similarly reports that just the attention stimulated by self-certification programs causes methane losses to fall drastically. At the same time, marine engine manufacturers are developing low-slip solutions for main and auxiliary engines.

In an ideal scenario in which overall losses of methane from biogas-based biofuels were to be reduced to 0.5%, the emissions intensity of the biofuel could be reduced by approximately 30 gCO_2eq/MJ (based on GWP100). Consequently, the amount of biofuel required to achieve the same emissions reduction would decrease by 25%. This translates into an immediate economic advantage for a ship operator. Furthermore, such low-emissions value chains eliminate the risk that a biogas-based biofuel may become non-compliant if regulations on methane emissions accounting become more stringent.

We encourage the shipping industry to consider biogas-based biofuels in their portfolio, but only if methane emissions along the value chain are demonstrably low. Independent and accredited certification of methane emissions in these value chains is highly beneficial to ensure the value of these biofuels in decarbonizing shipping operations, and we recommend that the shipping industry adopt dedicated certification programs to de-risk their alternative fuel procurement operations.



8. The project team

This report was prepared by the Mærsk Mc-Kinney Møller Center for Zero Carbon Shipping (MMMCZCS) with assistance from our partners. Team members marked with an asterix (*) were seconded to the MMMCZCS from partner organizations.

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Abbreviations

BOG	Boil-off gas
CCS	Carbon capture and storage
CH_4	Methane
CO_2	Carbon dioxide
COP	Conference of the parties
DTU	Technical University of Denmark
EBA	European Biogas Association
EPA	Environmental Protection Agency (US)
GHG	Greenhouse gas
GMP	Global Methane Pledge
GWP	Global warming potential
IEA	International Energy Agency
IMO	International Maritime Organization
LBM	Liquified bio-methane, also known as liquified biogas (LBG) or bio-LNG
LNG	Liquified natural gas
MMMCZCS	Mærsk Mc-Kinney Møller Center for Zero Carbon Shipping
Mt	Million (or mega) tonnes
SNG	Synthetic or substitute natural gas
t	Tonnes, metric tons (1,000 kg)
WTW	Well-to-wake

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