

Biogas as a Source of Biofuels for Shipping



Energy Demand for Emissions Reduction Compliance



Mærsk Mc-Kinney Møller Center
for Zero Carbon Shipping

Executive Summary

Decarbonization of the shipping industry will require access to a range of alternative low- or zero-carbon fuels in the coming years. This series of reports is a deep dive into the potential of biogas as a source of biofuels for shipping. Biogas, generated by anaerobic digestion of biomass, is a mixture of methane (CH₄) and carbon dioxide (CO₂) that can be easily transformed into various biofuels. The process of marine biofuel manufacture from biogas is broadly sketched in Figure 1.

Biofuels with a high *decarbonization efficiency* can effectively lower overall greenhouse gas (GHG) emissions when they replace fossil fuels. Converting biomass into biofuel often requires extensive chemical and physical processing, which consume both electricity and fuel. Manufacturing processes with high *conversion efficiencies* can produce more biofuel using fewer resources and/or creating less waste. The *emissions intensity* of a biofuel, based on the total GHG emissions associated with its manufacture and use, depends on multiple factors, including biomass type, origin of electrical power, and fugitive emissions. Both conversion efficiency and emissions intensity contribute to a given biofuel's *decarbonization efficiency*.

In this report, we explore select pathways for manufacturing of three biogas-based biofuels: liquified bio-methane (LBM), fuel-grade bio-methanol, and grade 'AA' bio-methanol. The pathways described in this study compare commercial manufacturing options for these fuels with alternatives at various stages of commercialization. We use mass and energy balances and emissions intensity calculations to understand how the biofuel type and the manufacturing value chain impact the energy demand required to reduce GHG emissions.

We find that the existing fully commercial route to LBM can yield an efficient decarbonization pathway if methane emissions along the pathway are controlled and the feedstock used is waste with no other uses. The decarbonization efficiency of this pathway can be further improved if the residual CO₂ can be captured and sequestered. This finding strikes a positive note, considering the upcoming mandatory emissions reduction targets for the shipping industry and the current scarcity of commercial decarbonization options.

Within the limitations of this study, we also find that biogas-based pathways are generally more energy-efficient when used for LBM production than for bio-methanol production. This result is unsurprising, since biogas contains high concentrations of methane, and bio-methanol can be produced more efficiently by other means. More consequentially, however, we find that the carbon intensities of the three biofuels in this study are much more sensitive to the optimization level of the value chain than to the biofuel type. Optimized value chains can deliver both LBM and grade 'AA' bio-methanol with strongly negative emissions.

In regulatory frameworks or voluntary schemes that impose emissions reduction targets on the basis of fuels' well-to-wake performance, a biofuel's emissions intensity affects the quantity of fuel required to satisfy a mandatory emissions reduction target. Our analysis shows that optimization of a biofuel value chain can halve the quantity of a given biofuel required for compliance with the 2030 reduction levels of the FuelEU Maritime Regulation, compared to the same biofuel obtained from non-optimized value chains. Thus, emissions intensity defines the biofuel's value with respect to emissions reduction compliance and must be included in a procurement assessment.

Optimization strategies for value chains are thus critical for a biofuel's market value. Unfortunately, the financial gains at stake have triggered cases of fraud, which were enabled by difficulty in tracing input resources and insufficient control. A rigorous certification process comprising origin of biomass, methane emissions, and sources of electricity is crucial to ensure that biofuels produced under optimized conditions deliver the anticipated GHG emissions savings.

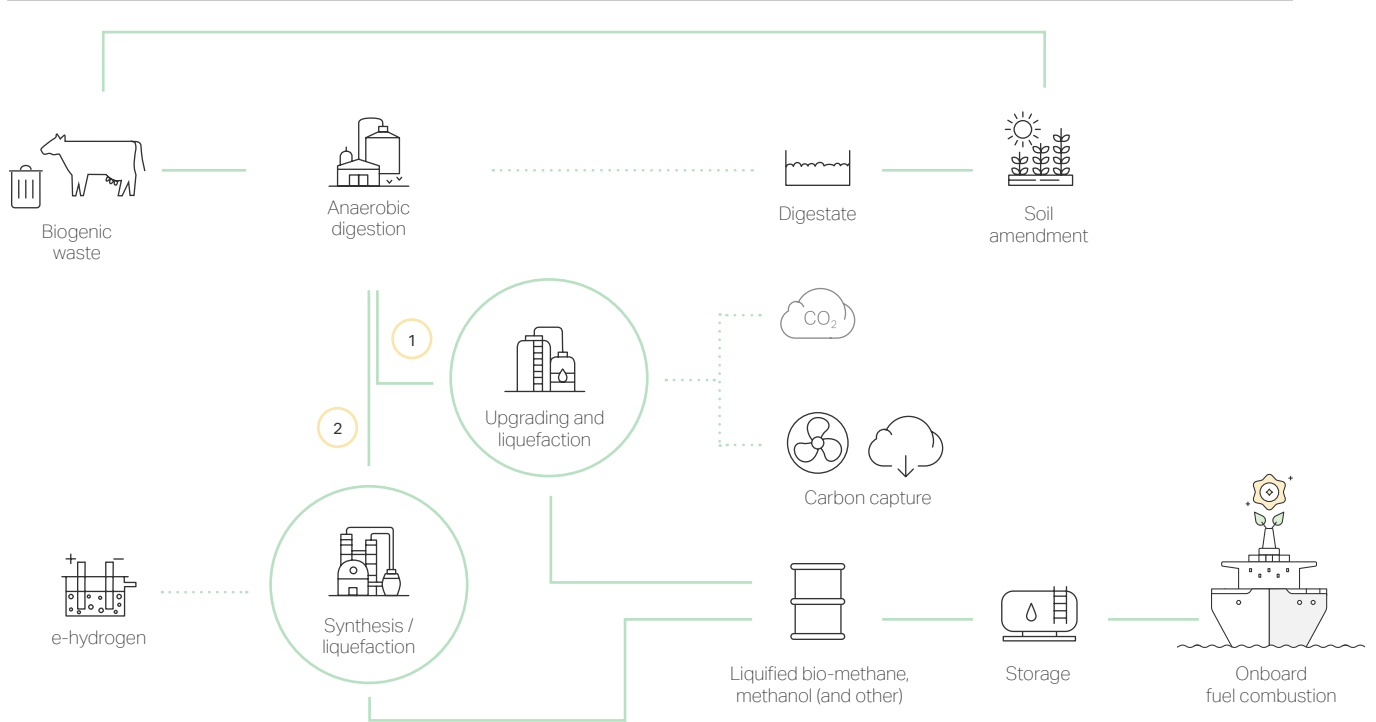
There is a high interest in biogas from other sectors outside the shipping industry. If shipping operators wish to improve their ability to control procurement costs, they may be able to do so by investing in accurately selected value chains and ensuring long-term supply agreements of biofuels with known emissions reductions and price. We recommend that shipping operators who have not yet settled on a specific biofuel should consider whether approaching decarbonization with a "project first" mindset can bring value to their operations. Building a biofuel supply chain requires approximately the same time as building a new ship —



therefore, operators may be able to optimize costs by first identifying and securing supply of a biofuel with an attractive total cost of ownership regardless of the

biofuel type and later procuring and building the ships that can operate on that biofuel.

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



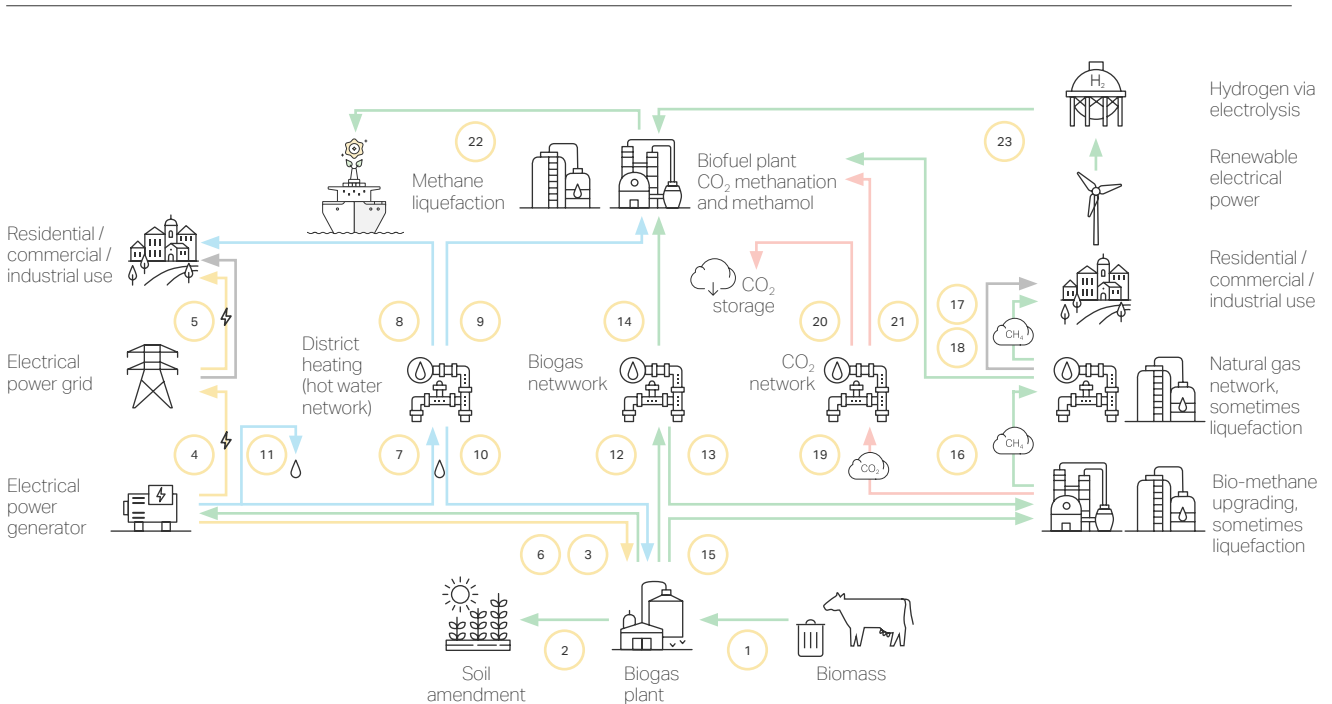
1. Introduction

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 (CH₄) and carbon dioxide (CO₂), 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 ‘[Biogas as a source of biofuels for shipping: insights into the value chain](#)’. That report also lays out various manufacturing pathways for production of LBM and bio-methanol from biogas and highlights the vast diversity of options available for a biogas plant to integrate into current and plausible future energy infrastructure (summarized in Figure 2).

Biomass is often a non-homogeneous material with few direct applications as an energy source. Transforming or converting biomass into a gas or liquid that can be conveniently stored and combusted for propulsion (i.e., a biofuel) often requires extensive chemical and physical processing. This processing is carried out with the help of electricity and fuels of fossil or biogenic origin. Manufacturing processes with high conversion efficiencies can do “more with less” — obtain more biofuel using less biomass, electricity, etc., and create less waste material or waste energy (typically in the form of non-utilizable heat). A high conversion efficiency is often necessary, but not sufficient, to ensure that a biofuel also has a high decarbonization efficiency.

Figure 2: Overview of LBM and bio-methanol manufacturing pathways integrated with other energy networks.



The *emissions intensity* of a given biofuel depends on the frame conditions of a manufacturing process — for example, the biomass type, origin of electrical power, and fugitive emissions. Emissions intensity is expressed as the sum of all greenhouse gases (GHGs) emitted during manufacturing and use of a given unit of biofuel. Biofuels with low emissions intensity have a high *decarbonization efficiency*, meaning that they effectively contribute to lowering overall GHG emissions when they replace fossil fuels.

As the world moves away from fossil fuels, demand for natural resources — such as biomass, renewable power, water, and labor — is set to, or already does, exceed supply.^{1,2} Therefore, in this study we aimed to investigate the demand for resources involved in the production and use of specific biogas-based biofuels in shipping. To this end, we have calculated the energy and material flows and well-to-wake (WTW) GHG emissions associated with biomass aggregation, biofuel manufacturing, transport, bunkering, and onboard methane emissions. We then use this information to assess how the biofuel type, manufacturing pathway, and value chain impact these biofuels' emissions intensity as well as the demand for both biofuel and resources required to comply with emissions reduction mandates such as the FuelEU Maritime Initiative.

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](#), [methane emissions](#), [WTW GHG emissions](#), [techno-economic trends](#), and [biomass availability](#).

The project was a collaboration between the MMMCZCS and our partners: Boston Consulting Group, Cargill, Maersk, Norden, Topsoe, and TotalEnergies. A full list of project participants is provided in Section 5.

Our project partners



2. Methods and scope of this study

2.1 Biofuels included in the study

In this report, we considered three biofuels: LBM, grade 'AA' bio-methanol (hereafter AA bio-methanol), and fuel-grade bio-methanol. We saw LBM as an obvious choice since biogas contains a significant amount of methane. AA bio-methanol is purified (nearly 100%) bio-methanol and was selected for the study based on growing interest from the shipping industry. Fuel-grade bio-methanol is an intermediate product from bio-methanol production containing some water and higher alcohols. Fuel-grade bio-methanol was included to explore options for reducing manufacturing costs by eliminating the purification step from the bio-methanol manufacturing process.

The specifications for LBM as a fuel for marine applications result from the liquefaction process as described by ISO 23306:2020.³ An ISO standard is in progress for bio-methanol fuel for marine applications.⁴ Some key characteristics of the fuels considered in this study are shown in Table 1.

As Table 1 shows, the energy density (by weight) of LBM is two and a half times higher than that of bio-methanol, meaning that a shipping operator must bunker two and a half times as much bio-methanol as LBM to supply the ship with the same propulsion energy. This does not have cost implications if the bunker price is based on the fuel's energy content, as is typical in fuel trading. However, it does have an impact on cost if bunker is traded based on weight, as is typical of chemicals.

Table 1: Composition and energy density of biogas-based biofuels included in this study.

	LBM	Fuel-grade bio-methanol	AA bio-methanol
Bio-methane	~99.9%	-	-
Bio-methanol	-	82-86%	>99.85%
Energy density as LHV, MJ/kg	49-50	14-17	19.9
Energy density as LHV, MJ/m ³	21,000	11,000-13,500	15,700

LBM = liquified bio-methane, LHV = lower heating value, MJ/kg = megajoule per kilogram, MJ/m³ = megajoule per cubic meter



2.2 System boundaries

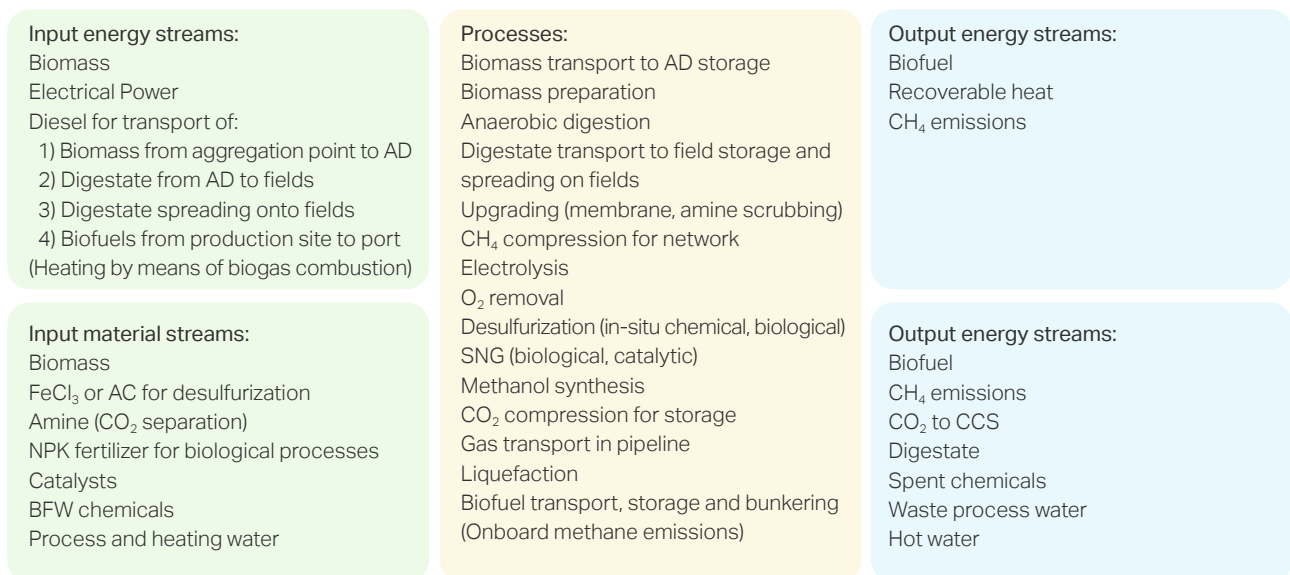
The system boundaries (or battery limits, in engineering terms) of this study are shown in Figure 3. The “system” comprises the processes listed in the center of the figure. The first process is transport of aggregated biomass to the anaerobic digester, and the final process is bunkering of biofuel (for bio-methanol) or onboard methane emissions (for LBM only). In between are all the processes required to transform the biomass into a biofuel. In addition to the processes, various “streams” enter and exit the system. The streams can be energy only (e.g., electricity), material and energy (e.g., biomass and biofuel), or material only (e.g., water at ambient temperature).

In this study, we have not considered onboard energy use from biofuels. Considering the qualitative character of this study, we assume the tank-to-wake fuel efficiency of LBM and bio-methanol propulsion to be broadly comparable. In this regard, we note that:

- Emissions of biogenic CO₂, such as those generated by the combustion of biofuels, are considered to be net-zero by definition, so all biofuels are equal in terms of CO₂ emissions from combustion;
- LBM and bio-methanol engines operate with similar efficiency;
- LBM propulsion may require additional energy compared to methanol for refrigeration, but bio-methanol has a lower energy density than LBM, and a ship propelled by methanol requires additional energy to carry the excess fuel weight. These energy losses are voyage-specific. Considering the qualitative character of this study, we have assumed that they roughly even each other out.

However, we have included onboard methane emissions as a part of the energy balance for LBM, in order to make an accurate comparison of the utilizable energy, i.e., the chemical energy that can be converted into propulsion energy, and as input to our [WTW GHG emissions study](#).

Figure 3: System boundaries for this study.



AD = anaerobic digester; AC = activated carbon; NPK = nitrogen, phosphorus, potassium; BFW = boiler feed water; SNG = synthetic natural gas; CCS = carbon capture and storage.



Our [WTW GHG emissions report](#) shows that typical emissions intensities of chemicals, catalysts, and water represent only a small portion of the environmental burden of the biofuel production pathways considered in our project. Thus, we have disregarded these materials in our discussion. Locally, however, these streams can have an important environmental burden. In particular, local availability of water can be an issue that, due to progressive desertification in many parts of the globe, may become more pronounced in the future. By way of example, the current standard emissions intensity of water only accounts for the climate burden related to water preparation to “process water” specifications. However, if suitable water is not readily available, additional processing (e.g., pipelining from remote locations, desalinization, enhanced wastewater treatment to increase recovery) must be accounted for. These additional processing steps add a higher climate burden and may tilt an assessment in favor of processes that use less water.

2.3 Method

For this study, we established energy and material balances for a selection of plausible biogas-based biofuel manufacturing pathways previously introduced in our companion report on [insights into the value chain](#). These pathways, which are described in detail in Section 2.5 of this report, were chosen to call attention to process, cost, and environmental performance.

We collated data from several different sources. Technology providers supplied energy and material balances for the anaerobic digestion, desulfurization, upgrading, methanol and methane synthesis, and methane liquefaction processes. To obtain values for CO₂ compression (part of CCS), we established our own model and verified its performance using publicly available data (see Table 2). For methane emissions, which were not reported by technology suppliers, we used the information generated in our companion report on [methane emissions](#). Assumptions used to calculate energy and material balances for transport of biomass to the anaerobic digestion site and transport of biofuel to port are detailed in Section 2.4 and Appendix A.

Table 2 and Table 3 summarize general information concerning the specific LBM and bio-methanol production processes included in the scope of our study. We assessed the technology readiness level (TRL) on a scale of 1-9 for each process by comparing public information with EU guidelines.⁵ The TRL is critical for understanding the likelihood that a technology can be deployed quickly enough to help the shipping industry meet 2025 and 2030 emissions reduction targets. The tables also show the typical scale of application of a technology and include some references for further information.

We chose to primarily focus our study on processes and technologies that are either already or nearly commercial (TRL=9). However, for processes that require hydrogen (Table 3), licensors supplied process information based on green hydrogen, which relies on electrolysis of water. Two specific electrolysis technologies were considered: solid oxide electrolyzer cells (SOEC) and proton exchange membrane (PEM). These have a lower TRL than alkaline electrolysis, which is more widespread in the market but less efficient in converting electricity to hydrogen. Based on these technology choices by the licensors, the pathways in Table 3 have a lower overall TRL.

The information in the two tables highlights that LBM can be manufactured using fully commercial processes today (Table 2), with some CO₂ compression technologies (for scenarios including CCS) being the only exception. In contrast, processes that require hydrogen addition (Table 3) require some technology maturation.



Traditional catalytic routes to manufacture synthetic natural gas (SNG) or bio-methanol require a constant hydrogen supply. However, green hydrogen from renewable electricity can only be made continuously available if storage of renewable power and/or hydrogen is envisaged. This so-called dispatchability of energy can be accommodated but it increases the cost of a project. For low-capacity projects connected to the electrical power grid, dispatchability can be ensured if electricity is sourced from the grid. Developments to eliminate this requirement are ongoing, and the success of such development is critical for the cost of manufacturing catalytic SNG and bio-methanol.

Similar processes with a higher TRL and fewer dispatchability issues may be established using, for example, blue hydrogen or bio-hydrogen; however, they are outside the scope of this study.

One of the strengths of the biological route to SNG manufacturing, which is under commercialization, is that it does not require a constant supply of hydrogen.

Due to the confidential nature of the information supplied by licensors, our results cannot be published in full. Instead, the results presented here focus on the aspects that we deem most consequential for understanding the performance of these pathways in view of the decarbonization of shipping.

Table 2: Processes to manufacture LBM that do not require hydrogen.

Process	Technology readiness level ⁵	Technology changes with production capacity?	Where to learn more
Anaerobic digestion	9	No change	Industry association websites ^{6,7,8} Encyclopedia of sustainable technologies (2017) ⁹
Desulfurization: in-situ	9	Mostly used when sulfur content is low in small plants	Bailon Alegue (2014) ¹⁰
Desulfurization: biological	9	Mostly used when sulfur content is medium-high	Bailon Alegue (2014) ¹⁰
Upgrading: membrane	9	Mostly in small plants	Baena-Moreno et al (2020) ¹¹ Soto et al (2022) ¹²
Upgrading: amine wash	9	Mostly in medium-large plants	Capra et al (2018) ¹³ Awe et al (2017) ¹⁴ Lawson et al (2021) ¹⁵
Bio-methane compression	9	No change	
CO ₂ compression	8-9	No information	Kearns et al (2021) ¹⁶
CO ₂ storage	9 (for saline formations and enhanced oil recovery)	Not relevant	Kearns et al (2021) ¹⁶
Methane liquefaction	9	Yes	Al-Mutaz et al (2016) ¹⁷ Linde Engineering, technical paper ¹⁸



Table 3: Processes to manufacture bio-methanol and boost LBM by means of hydrogen (H₂) addition.

Process	Approximate technology readiness level ⁵	Technology changes with production capacity?	Where to learn more
Catalytic SNG production	9 (with constant H ₂ supply)	No change	Dannesboe et al (2020) ¹⁹
Biological SNG production	8 (does not require continuous H ₂ supply)	No change	Bellini et al (2022) ²⁰ Rafrati et al (2021) ²¹ Hørlyk-Jensen (2021) ²² Electrochaea website ²³
Traditional steam reforming	9 (with constant feed supply)	It may change	Ullmann's Encyclopedia, Gas processing ²⁴
eREACT™	6-7	No available information	Topsoe blog ²⁵
Methanol synthesis (fuel-grade)	9 (with constant H ₂ supply)	No change	Ullmann's Encyclopedia, Gas processing ²⁶ Methanex webpage ²⁷
Upgrading to AA methanol	9 (with constant H ₂ supply)	No change	Ullmann's Encyclopedia, Gas processing ²⁶
SOEC-based electrolysis	6-8 ²⁸	No change	NREL ²⁹
PEM-based electrolysis	9 (but not proven at the needed capacity)	No change	NREL ²⁹

SNG = synthetic natural gas, eREACT™ = electrified steam methane reforming, SOEC = solid oxide electrolyzer cell, PEM = proton exchange membrane.



2.4 Basis of design

For the purpose of calculating overall energy and material balances of the selected manufacturing pathways (see Section 2.5), we asked various technology suppliers for the energy and material balances of their individual technology packages. Technology suppliers delivered information based on a basis of design specified by us. A basis of design is an engineering document that details the desired project outcome and/or the available input and the level of information such as plant capacity/size or type of biofuel. Inputs and outputs to the system, or “streams”, are described in Section 2.2.

In our basis of design, we specified a single biogas composition and physical state (temperature and pressure) as well as multiple production capacities (flowrates), as detailed in Table 4.

We gave this information as desired output to providers of anaerobic digestion technologies and as desired input to providers of upgrading, biological

desulfurization, and methanol and methane synthesis. This strategy worked satisfactorily for processes downstream of anaerobic digestion and allowed us to obtain licensors’ information on upgrading, biological desulfurization, and methanol and methane synthesis. However, it proved unrealistic for the processes within the anaerobic digestion area (biomass preparation, anaerobic digestion, and digestate handling). This is because biological processes must account for a large variability in biomass loading plans, and capturing the relationship between biomass input and biogas output requires a level of granularity that could not be made available.

Therefore, to simulate the energy and material balances associated with anaerobic digestion, we have used publicly available data from the Biovilleneuve bio gas plant (BioV) operated by Fonroche Biogaz (now TotalEnergies), for which a detailed analysis was available.³⁰ We scaled up the BioV data to match the composition and capacity requirements for our basis of design. Further details on both BioV and our scale-up, which are the basis for the calculations and conclusions in this report, are provided in Appendix A.

Table 4: Biogas specifications in the basis of design for this study.

Biogas composition (vol %)		Biogas physical state	
CH ₄	52.4	Temperature (°C)	40
CO ₂	42.5	Pressure (bar g)	0.5
H ₂ O	4.7		
N ₂	0.2	Capacities	
O ₂	0.2	Total biogas flowrates (methane and CO ₂) (Nm ³ /h):	500; 5,000; and 10,000
H ₂ S	0.25 (before rough desulfurization) 0.02 (after rough desulfurization)		



2.5 Biofuel manufacturing pathways

We combined the information we received from process licensors to understand how to optimize biogas-based biofuel production pathways in order to minimize emissions intensity and cost. The variables used in the study, shown in Table 5, resulted in 30 possible production pathways. For each pathway, we established energy and material balances analogous to those shown for the BioV plant in Appendix A, Section A.1, and we calculated the pathways' energy conversion efficiencies, life cycle emissions, and cost of manufacturing.

From the initial 30 pathways, we discarded all pathways using natural gas as a source of heat to produce biofuels, since this practice is losing acceptance. We excluded aggregation scenarios described in Appendix A, Section A.2.1 (aggregation of upgraded bio-methane via the natural gas grid) because of a lack of information on process performances for the bio-methanol routes. We also excluded aggregation scenarios described in Appendix A, Section A.2.2 (aggregation of biogas through dedicated pipelines). We did this because, from a process performance perspective, the results did not add more nuance to our conclusions over those obtained from the aggregation scenario in Appendix A, Section A.2.3 (large-capacity plant), which is already commercially established. Aggregation scenario A.2.2 is, however, relevant as a means to reduce the total cost of production, as we discuss further in our report on [techno-economic trends](#).

We ultimately selected nine pathways to focus on in this report. Variables relevant to these pathways are shown in darker hues in Table 5. The pathways can be divided into two categories: commercial processes, which use mostly biomass/biogas as energy input (standard LBM); and advanced processes, which boost biofuel production by means of hydrogen (SNG1, SNG2, BioMeOH1, and BioMeOH2). Table 6 outlines the steps and characteristics of the nine selected pathways.

All selected pathways are based on the same net biogas input to downstream operations (1.65 PJ/y) which corresponds to a net output from the anaerobic digestion facility of approximately 10,000 Nm³ biogas/h. Anaerobic digestion was modelled in a large-capacity plant, as described in Appendix A, Section A.2.3. Surplus production of biogas was needed to cover individual heat demand of various processes. Therefore, the gross biogas energy required by the processes changes from pathway to pathway, with the maximum difference being around 15%.

Important assumptions made in the course of our work to combine and integrate process steps into full pathways are described in Appendix A. The engineering design of a manufacturing unit must be tailor-made for the specific project conditions to ensure optimal performance, and integration details must be considered with expert knowledge. For these reasons, generalized studies like this one have a qualitative character. Therefore, we encourage the reader to focus on the trends that the results show, rather than on individual values.

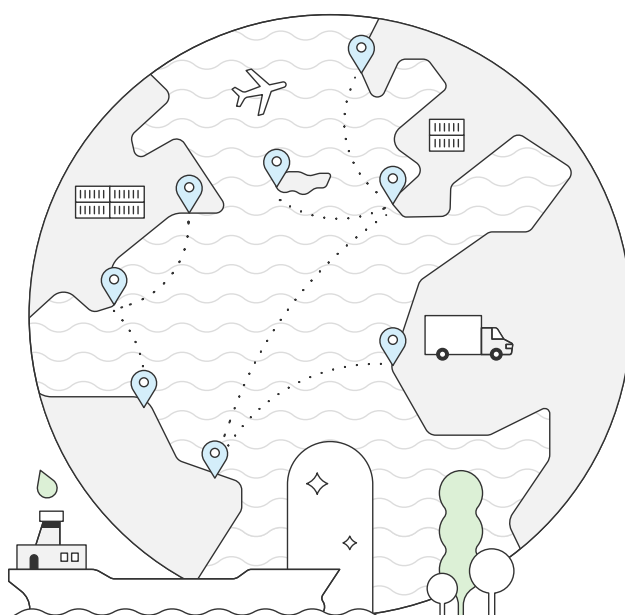


Table 5: Variables considered during initial generation of possible biofuel production pathways. Variables marked by a darker hue are discussed further in this report.

	BioV plant		For scale-up exercise	
Capacity aggregation	None	Transport of biomass by truck over longer distances	Transport of biogas by pipelines	Transport of biomethane by pipelines
Biofuel type	CBM to grid	LBM to ship	Fuel-grade bio-methanol	AA grade bio-methanol
Methane upgrading type	Membrane separation	Amine scrubber	Catalytic SNG	Biological SNG
Desulfurization type	In-situ with FeCl ₃	Biological desulfurization of CO ₂	Biological desulfurization of biogas	
Oxygen removal	None	None	By combustion of hydrogen	
Reformer type (bio-methanol)	None	Traditional	eREACT™	
Carbon capture and storage	None	None	CO ₂ captured from upgrader	CO ₂ captured from flue gases
Heat source	Natural gas	Natural gas	Biogas	
Biogas plant size (Nm ³ /h)	800	10,000		
Liquefaction plant size (MTPA)	None	2,500-50,000	50,000	
Biofuel transport to port	None	1,000 NM + 50 km		

Nm³/h = normal cubic meters per hour, MTPA = metric tons per annum, SNG = synthetic natural gas, NM = nautical miles. eREACT™ is an electrified steam methane reformer.



Table 6: Pathways selected for analysis in this report.

Pathway	Description	Process schematic
1a: st. LBM (commercial)	<p>Pathway 1a: standard LBM</p> <p>This is a commercial pathway to LBM consisting of an individual large biogas production facility, an amine upgrading unit to separate methane, and a biological desulfurization unit to remove sulfur from the CO₂ stream. Bio-methane liquefaction is carried out at the plant itself with a ~100 t/day liquefaction plant.</p>	
1b: st. LBM w. CCS (semi-commercial)	<p>Pathway 1b: standard LBM with CCS</p> <p>This pathway comprises the same process units as pathway 1a, but also includes a CO₂ purification unit to remove O₂, CO₂ compression and transmission via pipeline, and CO₂ storage. To our knowledge, the application of CCS to CO₂ from biomethane upgrading has not yet been tried in any commercial process.</p>	
2: LBM w. SNG1 (advanced)	<p>Pathway 2: LBM with SNG 1</p> <p>This pathway uses a catalytic process to boost LBM by converting CO₂ to methane using hydrogen. Biological desulfurization is carried out on the raw biogas stream and introduces some oxygen, which must be removed prior to catalysis. CO₂ is converted into methane using added hydrogen. Catalytic methanation produces high heat, which can be integrated into the SOEC plant. The exit stream contains almost 100% pure methane, which is subsequently liquified.</p>	



Table 6: Pathways selected for analysis in this report.

Pathway	Description	Process schematic
3: LBM w. SNG2 (advanced)	<p>Pathway 3: LBM with SNG 2</p> <p>This pathway uses a biological process to boost LBM by converting CO₂ to methane using hydrogen. Biological methanation tolerates sulfur and is carried out immediately after anaerobic digestion. The product stream contains some unconverted CO₂, separated by means of amine scrubbing. The CO₂ stream is cleaned of sulfur prior to release. For SNG2, we have modelled a SOEC plant based on public data,³¹ with no heat integration due to incompatible temperatures of the streams.</p>	
4: FG BioMeOH1 (advanced)	<p>Pathway 4: Fuel-grade bio-methanol 1</p> <p>This pathway produces fuel-grade bio-methanol using traditional steam methane reforming. Biological desulfurization and O₂ removal are required to prepare the feedstock for methanol synthesis. Reforming is sustained by means of combustion of biogas. Electrolysis and bio-methanol synthesis are integrated by the licenser. A flue gas stream with ~14% CO₂ is vented. Onboard GHG emissions are “zero” (only biogenic CO₂, no methane or other GHGs).</p>	
5: FG BioMeOH2 (advanced)	<p>Pathway 5: Fuel-grade bio-methanol 2</p> <p>This pathway produces fuel-grade bio-methanol using eREACT™ technology. Biological desulfurization and O₂ removal are required to prepare the feedstock for methanol synthesis. Reforming is sustained by means of additional electricity. Electrolysis and bio-methanol synthesis are integrated by the licenser. Nearly all biogenic CO₂ is used. Onboard GHG emissions are “zero” (only biogenic CO₂, no methane or other GHGs).</p>	



Table 6: Pathways selected for analysis in this report.

Pathway	Description	Process schematic
6a: AA BioMeOH1 (advanced)	Pathway 6a: AA bio-methanol 1 Same as Pathway 4, but the bio-methanol is distilled to obtain high-purity (grade AA) bio-methanol.	
6b: AA BioMeOH1 w. CCS (advanced)	Pathway 6b: AA bio-methanol 1 with CCS Same as in Pathway 6a, but CO ₂ is captured from the flue gas by means of an amine scrubber, compressed, and stored.	
7: AA BioMeOH2 (advanced)	Pathway 7: AA bio-methanol 2 Same as Pathway 5, but bio-methanol is distilled to obtain high-purity (grade AA) bio-methanol. In this case, no CCS is possible since the process uses all the CO ₂ to make biofuel.	

LBM = liquified bio-methane, CH₄ = methane, CO₂ = carbon dioxide, H₂S = hydrogen sulfide, H₂ = hydrogen, O₂ = oxygen, SNG = synthetic natural gas, SOEC = solid oxide electrolyzer cell, FG = fuel-grade, BioMeOH = bio-methanol, SMR = steam methane reforming, CH₃OH = methanol, H₂O = water, HA = higher alcohols, eREACT™ = electric steam methane reforming, GHG = greenhouse gas.



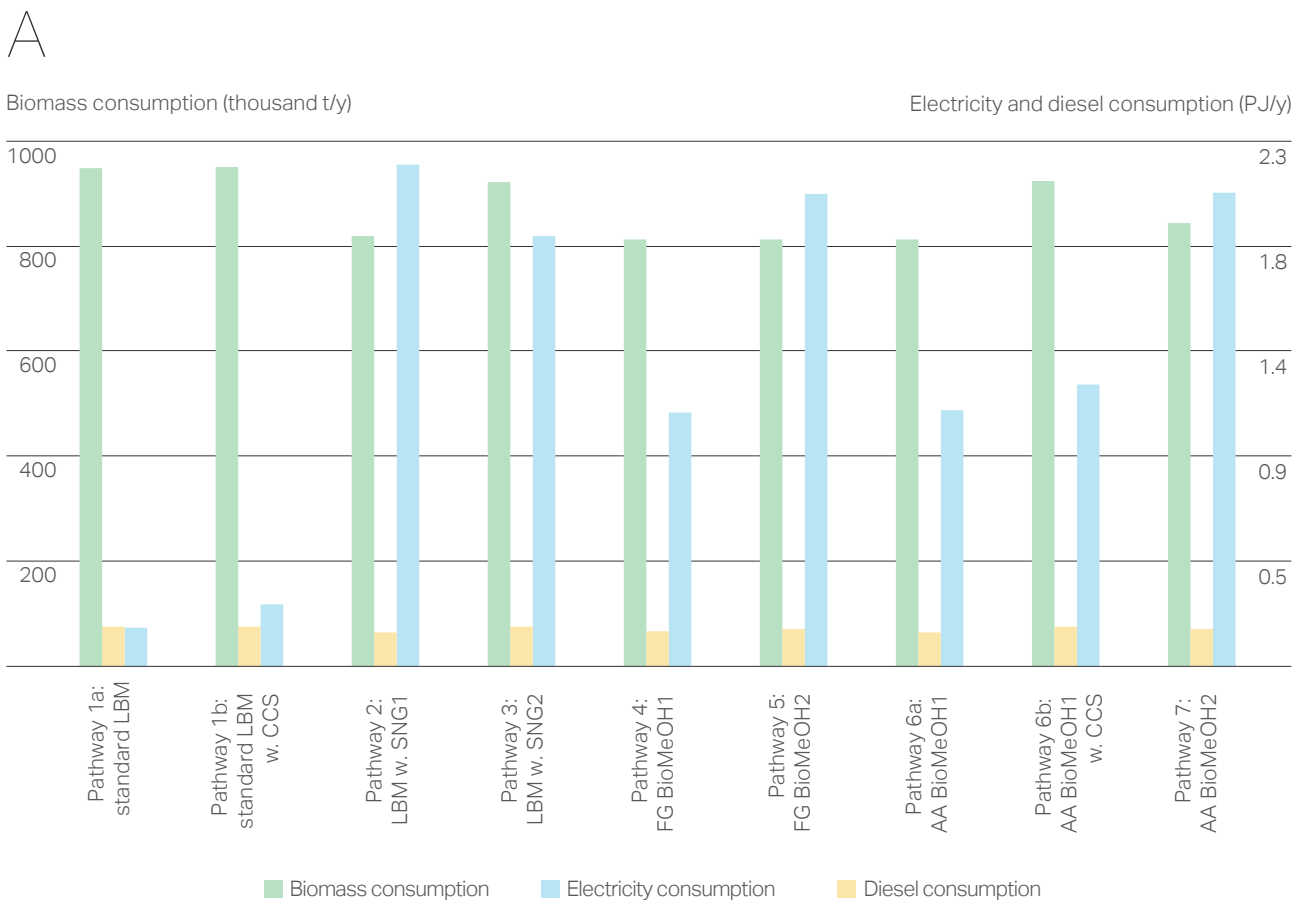
3. Results

3.1 Mass and energy balances

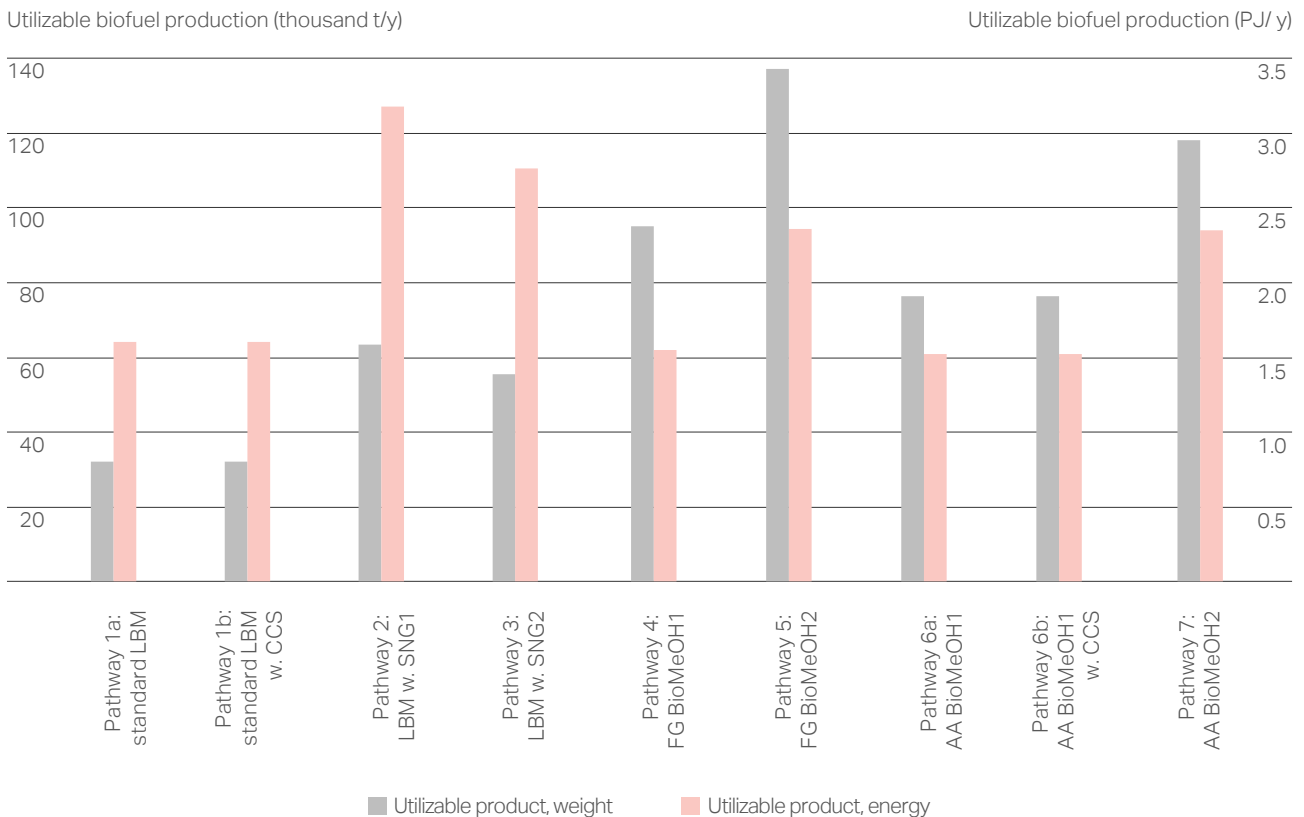
Figure 4 shows the mass and energy balances for a net biogas production of 1.65 PJ/y from our nine selected pathways, limited to the main streams: biomass, diesel, and electricity as input; and biofuel as output to the overall system inside the system boundaries specified in Section 2.2.

As context for the interpretation of Figure 4, we note that, due to methane slip from the main and auxiliary engines and other fugitive emissions, ships operating on LNG or LBM do not utilize all the bunkered fuel. On the other hand, combustion of bio-methanol is not associated with any fuel loss. Consequently, the energy available for vessel propulsion, relative to the energy content of the fuel produced, is generally lower for LBM than for bio-methanol.

Figure 4: Main inputs and outputs for all production pathways to achieve a biogas production of 10,000 Nm³/h or 1.65 PJ/y (net input for downstream processing). Panel A depicts consumption of biomass, electricity, and diesel. Panel B shows biofuel production by both weight and energy. Biofuel production is shown in terms of “utilizable” product at the ship, specifically referring to the energy released from onboard bunker combustion.



B



From these results, we can observe the following:

1. Biomass consumption (Figure 4A, light green bars) shows some slight variations depending on the thermal energy needs of the process. Biomass consumption is higher for all pathways that include an amine scrubber (Pathways 1, 3, and 6), which needs heat to regenerate the amine solution.
2. Electricity consumption (Figure 4A, light blue bars), by contrast, changes significantly depending on the pathway. Production of standard LBM (Pathway 1) consumes relatively little electricity — in the range of 0.17–0.26 PJ/y. The higher end of this range results from adding CCS in Pathway 1b, due to the electrical power required to compress CO₂.

All advanced pathways (Pathways 2–7), which require electricity to power the electrolyzer, have considerably higher electricity consumption than standard LBM production. Pathway 2 has the highest overall electricity consumption, mainly from electrolysis and liquefaction of methane. Pathway 3 consumes less

electricity than Pathway 2 due to its lower conversion rate of CO₂ into SNG, with a consequently lower demand for hydrogen and electricity for liquefaction.

Pathways 5 and 7, which fully convert biogas into bio-methanol by means of an electric reformer, require electricity for both electrolysis and reforming. These pathways have the second-highest demand for electricity. Electricity consumption for distillation is negligible, and this results in similar electricity demand for fuel-grade and AA-grade bio-methanol.

Pathways 4 and 6 do not achieve full conversion of biogas into methanol because they use biogas to supply heat to a traditional reformer. They do not consume as much electricity as the other bio-methanol pathways, but their production of bio-methanol is consequently lower (see Figure 4B).

3. The diesel consumption for transport (Figure 4A, light orange bars) broadly follows the biomass consumption. Diesel is also used for bunker transport, but this contribution is minor within the



assumptions of this study. Diesel consumption is generally low compared to electricity consumption.

4. The standard LBM production pathways (Pathways 1a and 1b) produce the lowest quantities (by weight) of utilizable biofuel (Figure 4B, gray bars), at roughly 32,000 t/y. These pathways use only the methane fraction of biogas to produce LBM, with the CO₂ fraction being rejected or captured for CCS. By contrast, the advanced pathways (Pathways 2–7) also use the CO₂ fraction to make biofuels and can therefore produce much more end product. For example, Pathways 2 and 3 can double the production of LBM (~60,000 t/y) seen in Pathway 1. Pathways 5 and 7 have a four-fold higher production of bio-methanol with respect to Pathway 1, at nearly 140,000 t/y and 120,000 t/y, respectively.
5. However, a comparison based only on the production capacity in terms of weight does not take into account the different energy densities of the fuels (see Table 1 for a comparison of the biofuels' LHV_s). When the output is expressed in terms of utilizable energy (Figure 4B, pink bars), the picture changes: the SNG pathways (Pathways 2 and 3) deliver the most, with SNG1 delivering more than 3 PJ/Y of utilizable energy. Furthermore, Pathway 1 produces LBM with approximately the same utilizable energy as the bio-methanol from pathways based on traditional methane reforming (Pathways 4 and 6).

Comparing only energy and material flows does not give a full overview of these pathways' value from a decarbonization perspective. To do that, we next interpreted the energy and material flows in terms of energy conversion efficiency and decarbonization efficiency.

3.2 Energy conversion efficiency

We calculated the pathways' energy conversion efficiency as the energy in the utilizable product divided by the energy input. Figure 5 shows the energy conversion efficiency for the nine selected pathways, scaled on the right vertical axis, along with input and output energy flows, scaled on the left vertical axis. For convenience, energy flows are scaled in both PJ and thousands of tons of oil equivalent (kTOE).

In this study, the biogas production and biomass input are directly correlated. Since the energy content of biomass was unknown, we have used biogas as a proxy for biomass in the energy balances. The output energy is partly in the utilizable biofuel, partly in methane emissions, and partly in heat.

Heat may be partially recovered by process integration within the same production plant. The excess heat produced in the plant may be either lost or recovered and used by industrial or residential consumers. The fate of excess heat must be studied for each individual project, and we have therefore decided not to account for it here due to the general character of this study. The excess heat is therefore accounted for under "losses" in Figure 5.

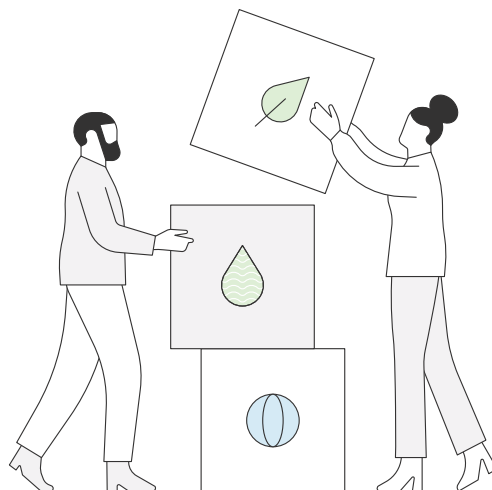
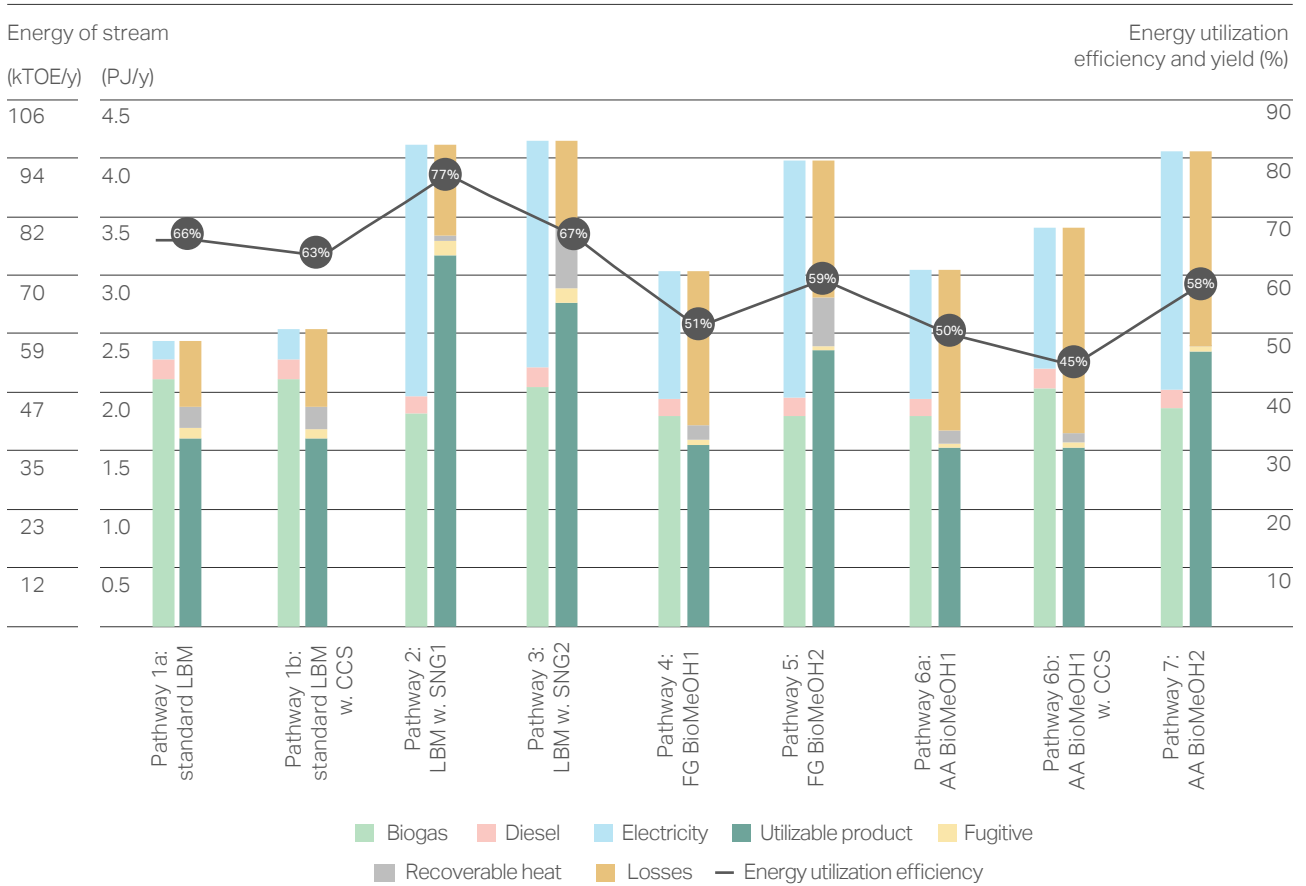


Figure 5: Energy balances for nine selected biogas-based biofuel production pathways. For each pathway, the left stacked column shows energy of input streams and the right stacked column shows energy of output streams, in both PJ/y and kTOE/y (scaled on left vertical axis). The black line shows energy conversion efficiency (energy in utilizable product divided by energy in input) (scaled on right vertical axis).



This analysis produces several conclusions in relation to energy, energy conversion, and feedstock utilization:

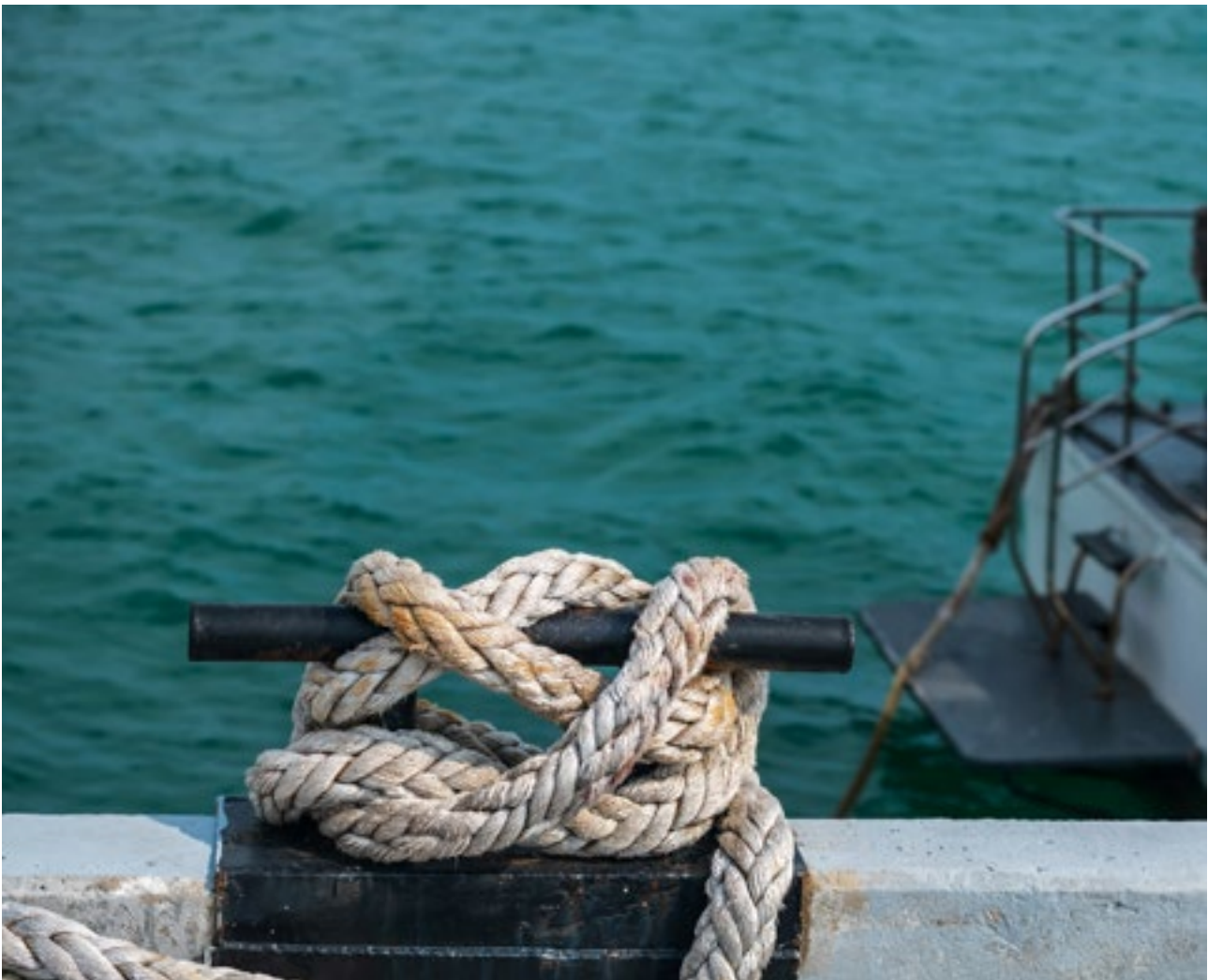
1. The gross biogas input mirrors the biomass consumption shown in Figure 4A, and varies between 1.8 and 2.1 PJ/y (or 42 to 49 kTOE/y). The maximum relative change is 17%.
2. Fugitive emissions mostly depend on the biofuel type and are higher in LBM pathways due to the contribution of onboard methane slip. By contrast, the bio-methanol pathways also have emissions associated with the anaerobic digestion steps but have no onboard emissions. Fugitive emissions make only a modest contribution to the energy balance of a given pathway but a massive contribution to the emissions intensity (see Section 3.3).
3. For the nine pathways analyzed here, the energy conversion efficiency of LBM is higher than that of bio-methanol. Pathway 2, in particular, achieves an energy conversion efficiency of nearly 80%. Meanwhile, bio-methanol produced via the electrical reformer (BioMeOH2, both grades) just nears the 60% threshold, and bio-methanol produced via conventional reformer (BioMeOH1, both grades) remains around 50%. This is expected, since bio-methanol manufacturing must first split the methane molecule, which requires energy. Other manufacturing pathways for bio-methanol that do not require methane reforming — for example, via biomass gasification — may have higher conversion efficiencies.



4. The choice of fuel-grade bio-methanol versus AA bio-methanol has a minor effect on energy conversion. Both Pathways 6 and 7 (AA BioMeOH1 and AA BioMeOH2) lose about one percentage point in energy conversion efficiency compared to their equivalent fuel-grade pathways (Pathways 4 and 5, respectively) due to the additional operations involved in bio-methanol distillation. However, since AA bio-methanol has a higher energy density than fuel-grade bio-methanol, its bunkering requirements are lower in terms of both volume and weight. Therefore, AA bio-methanol qualitatively seems to be a superior choice for economic and compliance reasons.
5. Adding CCS to the standard LBM process (Pathway 1b) results in an energy conversion efficiency loss of about 3%. In this pathway, CO₂ is already separated

and desulfurized, and the stream only requires purification and compression before storage. The impact of CCS on the energy conversion efficiency of bio-methanol is higher (approximately 5%) because the CO₂ must first be separated from the flue gas.

Overall, this analysis highlights that the relative strengths of biofuel types and manufacturing pathways with respect to one another are defined by important trade-offs. LBM pathways have a high production efficiency but also high methane fugitive emissions with respect to bio-methanol pathways. Additionally, the standard commercial LBM pathway has high biomass consumption but low electricity consumption with respect to the advanced pathways.



3.3 Decarbonization efficiencies

The FuelEU Maritime Initiative (FuelEU)³² is an example of a regulatory framework that specifically imposes limits on the WTW GHG emissions intensity of marine fuels. FuelEU establishes a series of emissions reduction targets which must be achieved through low-carbon fuels that comply with the sustainability criteria laid out in the latest version of the Renewable Energy Directive (RED). RED II affirms the sustainability criteria for biofuels in Article 29, Chapter 10, stipulating minimum GHG savings with respect to the relevant fossil fuel comparator.³³ The targets are higher for newer plants — minimum savings of up to 65% for biofuel plants that have commenced production after 1 January 2021.³³ A recent amendment to RED II, sometimes referred to as RED III, has not changed these targets.³⁴ The fossil fuel comparator for RED II is

set at 94 gCO₂eq/MJ. Thus, biofuels produced in new plants are eligible for FuelEU only if their emissions intensity is less than 32.9 gCO₂eq/MJ, following the RED II calculation methodology.

Our accompanying report on [WTW GHG emissions](#) discusses in depth the theory behind emissions intensity calculations for several pathways and calculation cases. The [WTW GHG emissions](#) report also suggests how a biofuel producer can optimize a value chain, defined as a combination of a pathway with specific inputs to the system, in order to minimize the emissions intensity.

For the current report, we have selected a limited number of calculation cases to test the response of our selected biofuel production pathways to different frame conditions. The cases are described in Table 7.

Table 7: Calculation cases for WTW GHG emissions assessment.

Case	Name	Description
1	Base case	<p>Burden for:</p> <ol style="list-style-type: none"> 1. Electricity, with emissions intensity of the French grid; 2. Diesel (transport); 3. No feedstock displacement burden except for manure (displacement with synthetic fertilizer); 4. Methane emissions based on the “typical” case described in our companion report on methane emissions; 5. Water and chemicals. <p>Credit for:</p> <ol style="list-style-type: none"> 6. Avoided methane emissions from manure; 7. Avoided synthetic fertilizer (all digestate); 8. CCS (Pathways 3 and 8 only).
2	Base case with average EU el	<p>Same as base case except for:</p> <ol style="list-style-type: none"> 1. Electricity, with emissions intensity of the EU grid (burden) <p>The emissions intensity of average EU electricity is around 6 times as high as in the French grid due to the high prevalence of nuclear power in France.</p>
3	Base case with extra methane emissions	<p>Same as base case except for:</p> <ol style="list-style-type: none"> 4. Methane emissions (burden) <p>We assumed methane emissions (slip and fugitive) to be 200% of their typical value.</p>
4	Base case with feedstock credits	<p>Same as base case except for:</p> <ol style="list-style-type: none"> 6. Feedstock credits (credit) <p>Feedstock credits may be earned if waste that otherwise would be disposed of in uncontrolled landfill is collected and processed in a biogas plant. In this calculation case, we have assumed that 30% of industrial waste can yield feedstock credits.</p>



Case	Name	Description
5	Base case with feedstock displacement	<p>Same as base case except for: 3. Feedstock displacement (burden)</p> <p>We assume that 100% of agricultural and industrial residues can be used elsewhere. By routing the feedstock into biofuel production, the deprived industries must find alternatives that have a burden on climate. Further details are given in the WTW GHG emissions report.</p>
6	Base case with "0" el	<p>Same as base case except for: 1. Electricity, emissions intensity assumed to be zero;</p> <p>This is unrealistic in most applications because it disregards carbon emissions for maintenance or construction but is indicated in some regulatory frameworks (e.g., EU RED II).</p>
7	Case 6 with feedstock credits	<p>Same as calculation case 6 (base case with "0" el) except for 4. Feedstock credits (credit): as in Case 4.</p>
8	Case 6 with feedstock displacement	<p>Same as calculation case 6 (base case with "0" el) except for 2. Feedstock displacement (burden): as in Case 5.</p>

El=electricity

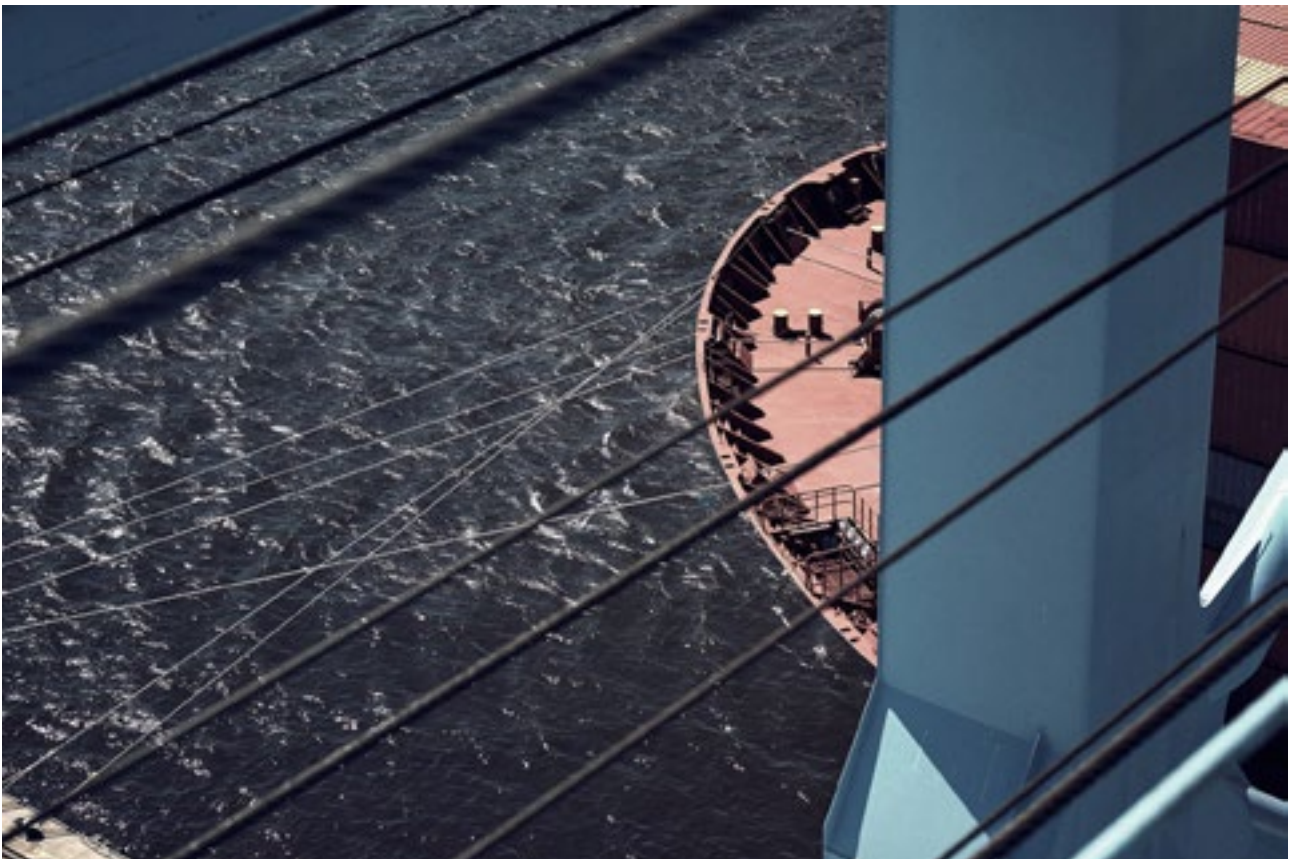
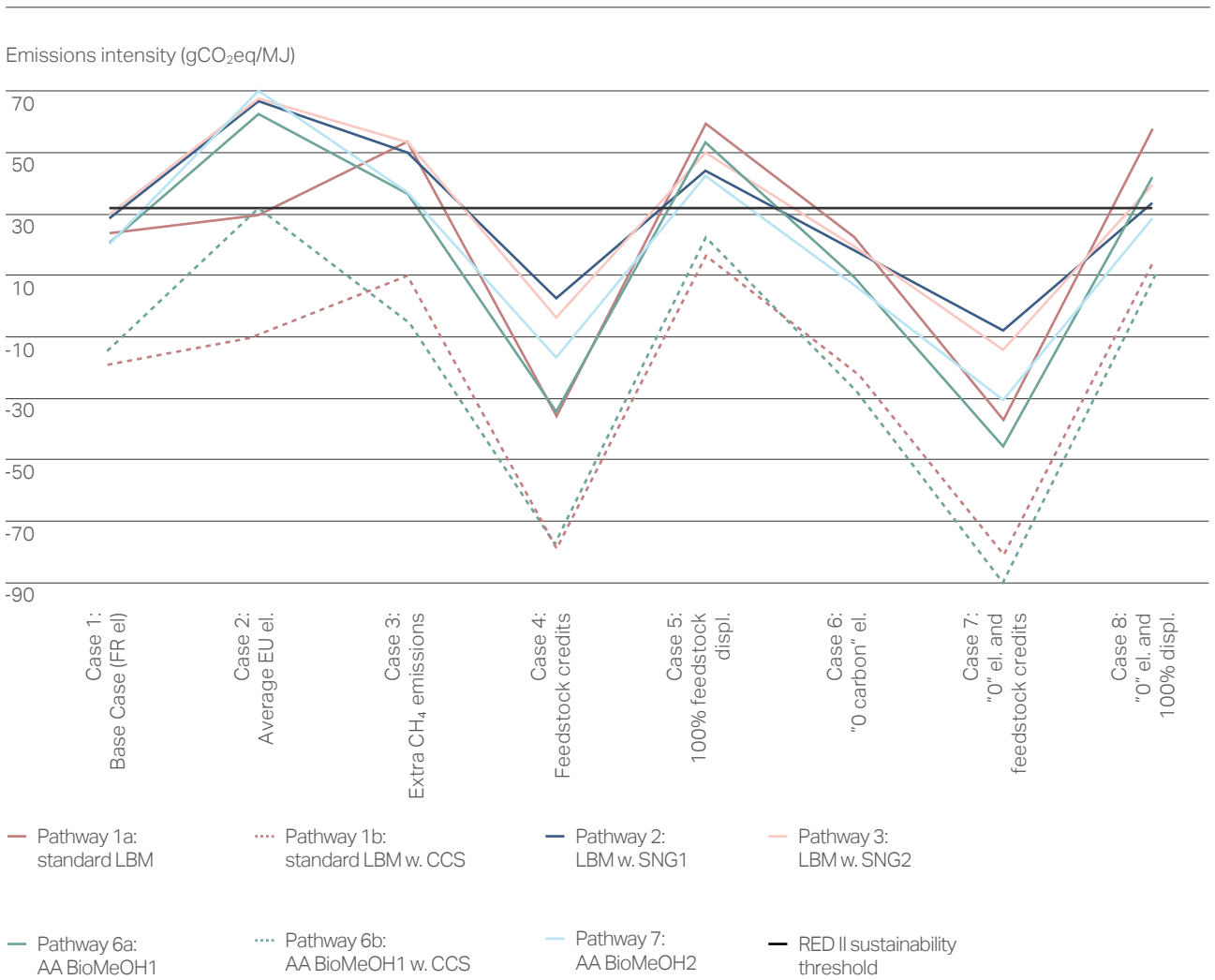


Figure 6 shows the results of this WTW GHG emissions assessment expressed as carbon intensity of the whole value chain. The emissions intensity is shown in gCO₂eq/MJ and is calculated by dividing the total amount of GHG emitted through the value chain by the energy of the bunkered biofuel. We have excluded the pathways to fuel-grade bio-methanol (Pathways 4 and 5) because our previous analysis suggested that this fuel would be of less commercial interest than AA bio-methanol.

Figure 6: WTW GHG emissions intensities of selected biofuel production pathways based on different calculation cases as detailed in Table 7.



Based on study of these calculation cases and their impact on emissions intensity, we can make several important observations:

1. Capture and sequestration of available CO₂ (dashed lines) invariably results in the lowest emissions intensity, regardless of the calculation case. For these pathways, the emissions intensity was often strongly negative. We calculated a minimum of -90 gCO₂eq/MJ for Pathway 6b (AA biomethanol with CCS, green dashed line) in Case 7.
2. For Case 1 (base case), all pathways produce biofuels with similar WTW GHG emissions intensities of approximately 20-25 gCO₂eq/MJ (excluding the CCS pathways). Furthermore, all pathways produce biofuels that qualify according to the RED II sustainability criteria, but only the CCS pathways (maroon and green dashed lines) distinguish themselves with low carbon intensities.
3. If using electricity from a grid with the EU average emissions intensity (Case 2), all advanced pathways except Pathway 6b (green dashed line) exceed the minimum sustainability criteria for RED II. Standard LBM with and without CCS (Pathway 1, maroon lines) can still qualify.
4. If the pathways are affected by high methane emissions (Case 3), only the CCS pathways (maroon and green dashed lines) are compliant with RED II. Bio-methanol pathways have lower emissions than LBM pathways in Case 3, which was the only calculation case showing a clear difference in performance based on fuel type. The resulting bio-methanol still exceeds the RED II qualification threshold if CCS is not applied.

This sensitivity to methane emissions underscores the importance of proper monitoring, reporting, and verification of methane emissions for all biogas-based biofuel pathways. If biogas-based biofuels are to be successful as low-emissions alternatives, the associated methane emissions must be consistently low throughout the value chain. Hence, regulation and certification of methane emissions are of the utmost importance. This topic is described further in our companion report on [methane emissions](#).

5. If a value chain can access certified feedstocks that give rise to carbon credits (Case 4), biofuels with negative emissions intensities can be produced from

all the pathways. Emissions intensity is particularly low for the pathways that include CCS (maroon and green dashed lines), which yield biofuels with emissions intensities of approximately -80 gCO₂eq/MJ.

When feedstock credits are available, pathways that require large amounts of biomass (e.g., Pathways 1 and 6, maroon and green lines), benefit from higher credits than pathways that rely mostly on electricity. For example, in Case 4, Pathway 6a (BioMeOH1, green line) achieves a lower emissions intensity than Pathway 7 (BioMeOH2, pale blue solid line) or Pathways 2-3 (SNG pathways, mid-blue and pink solid lines) because it benefits from higher credits. Assessing carbon credits for avoided emissions is another area where control is difficult and attempts of fraud may be expected. Certification and controls are of paramount importance to prevent deceptive claims.

6. Using feedstocks that carry displacement effects (Case 5) results in value chains with higher emissions intensity. While the CCS pathways (maroon and green dashed lines) still deliver biofuels with the lowest emissions intensity, pathways that consume less biomass (for example, Pathways 2, 3, and 7 – blue, pink, and pale blue solid lines) perform better than Pathways 1 (LBM, maroon solid line) or 6a (BioMeOH1 without CCS, green solid line).
7. Access to zero-emissions electricity (Case 6) causes all pathways to have negative emissions intensities. In this case, the advanced pathways (Pathways 2-7) perform better than the standard LBM (Pathway 1).
8. Access to zero-emissions electricity together with feedstock credits (Case 7) again causes all bio-fuels to have negative emissions, and biofuels consuming more biomass to benefit more, as seen in Case 4.

This is also true in Case 8, in which the pathways have access to zero-emissions electricity but carry a carbon burden due to using feedstocks with displacement effects. For this calculation case, Pathways 2, 3, and 7 (SNG1, SNG2, and BioMeOH2 – blue, pink, and pale blue solid lines) become more competitive thanks to their lower biomass consumption. Pathways 2 and 3 (blue and pink solid lines) produce LBM with similar emissions intensity to the bio-methanol produced using Pathway 6a (green solid line), but not as low as



that produced using Pathway 7 (pale blue solid line). As usual, the two CCS pathways (Pathways 1b and 6b with CCS, maroon and green dashed lines) deliver the biofuels with the lowest emissions intensity.

We can also see that, overall, the WTW emissions intensity of biofuels delivered by the pathways in this study varies very substantially — between +70 and -90 gCO₂eq/MJ — across the different calculation cases (Figure 6). These massive differences have important consequences for procurement, which are explored further in Section 3.4. Additionally, we describe a supplementary analysis of the total decarbonization potential of these production pathways in Appendix B of this report.

On an optimistic note, we found that the standard LBM manufacturing pathway (Pathway 1a), which is based on technologies that are fully commercial and available today, can deliver very interesting performances if it is produced with feedstocks that do not carry displacement effects.

Furthermore, a standard LBM manufacturing process coupled with CCS (Pathway 1b) consistently delivers a biofuel with very low emissions intensity and some of the highest overall decarbonization performances. Since these manufacturing pathways are technologically mature and commercially available, shipping operators can already consider options to include them in their bunkering strategies for compliance with emissions reductions targets.



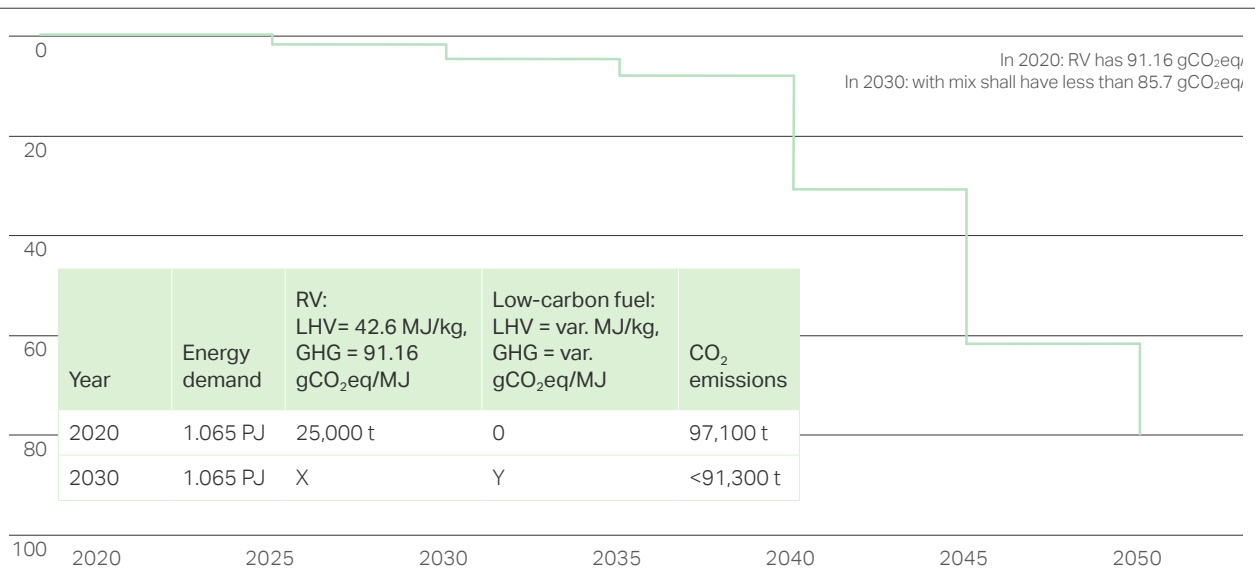
3.4 Implications for compliance with emissions reduction regulations

To put the impact of regulatory framework on biofuel demand into perspective, we can use an archetype fleet regulated by FuelEU Maritime (Figure 7). The fleet needs 1,060 TJ (1.06 PJ) of energy, which it obtains by consuming 25,000 t/y of reference marine fuel. The reference marine fuel is calculated based on the average 2020 emissions intensity of 91.16 gCO₂eq/MJ.

With this value, termed the fossil fuel comparator (FFC), the fleet emits 97,100 t of CO₂eq in a year.

By 2030, the fleet must lower the emissions intensity of its fuel mix by 6% (5,826 t) to roughly 91,300 tCO₂eq. This emissions reduction can be achieved using a combination of Y t of biofuel and X t of conventional marine fuel, where the values of X and Y required to achieve compliance depend on the energy density and emissions intensity of the biofuel.

Figure 7: Fuel consumption and GHG emissions of an archetype fleet consuming 25,000 t/y of marine fuel oil.



WTW = well-to-wake, RV = reference value, LHV = lower heating value, GHG = greenhouse gas, var.= variable.

The values of X and Y can be found by solving the mass and energy balances as follows:

$$(1) E_T = 1.065 \text{ PJ/y} = E_F + E_B = (X \times \text{LHV}_F + Y \times \text{LHV}_B) \times 10^{-6}$$

$$(2) \text{GHGe}_T = 91,300 \text{ t} = \text{GHGe}_F + \text{GHGe}_B = (X \times \text{Cl}_F \times \text{LHV}_F + Y \times \text{Cl}_B \times \text{LHV}_B) \times 10^{-3}$$

The solution being:

$$Y = \frac{(\text{GHGe}_T \times 10^3 - E_T \times 10^6 \times \text{Cl}_F)}{(\text{Cl}_B - \text{Cl}_F) \times \text{LHV}_B}$$

$$X = \frac{E_T \times 10^6 - Y \times \text{LHV}_B}{\text{LHV}_F}$$

Where:

- B means biofuel
- Cl means emissions intensity in gCO₂eq/MJ = kgCO₂eq/GJ = ktCO₂eq/PJ
- E means yearly energy in PJ/y
- F means marine fuel
- GHGe means yearly greenhouse gas emissions in tCO₂eq/y
- LHV means the lower heating value of the fuel (a measure of the energy density) in MJ/kg = GJ/t
- X is yearly demand for fossil marine fuel, as weight in t/y
- Y is yearly demand for biofuel, as weight in t/y
- T means total



Figure 8 shows how X and Y depend on the emissions intensity of the biofuel. The green continuous line, scaled on the left-hand side, shows the required energy from biofuels to meet the FuelEU threshold for 2030 in PJ/y. This value depends upon the biofuel emissions intensity but is the same for both bio-methane and bio-

methanol. The clustered bars, scaled on the right-hand side, show the weight of biofuel per year required to supply a given amount of energy. The weight of AA bio-methanol required for compliance is more than twice the amount of LBM due to the difference in their energy densities.

Figure 8: Biofuel (LBM or AA bio-methanol) required for compliance with a 6% WTW emissions reduction mandate for a fleet using 1.06 PJ/y of energy. All pathways reduce WTW emissions by 5,826 tCO₂eq compared to 2020 values.

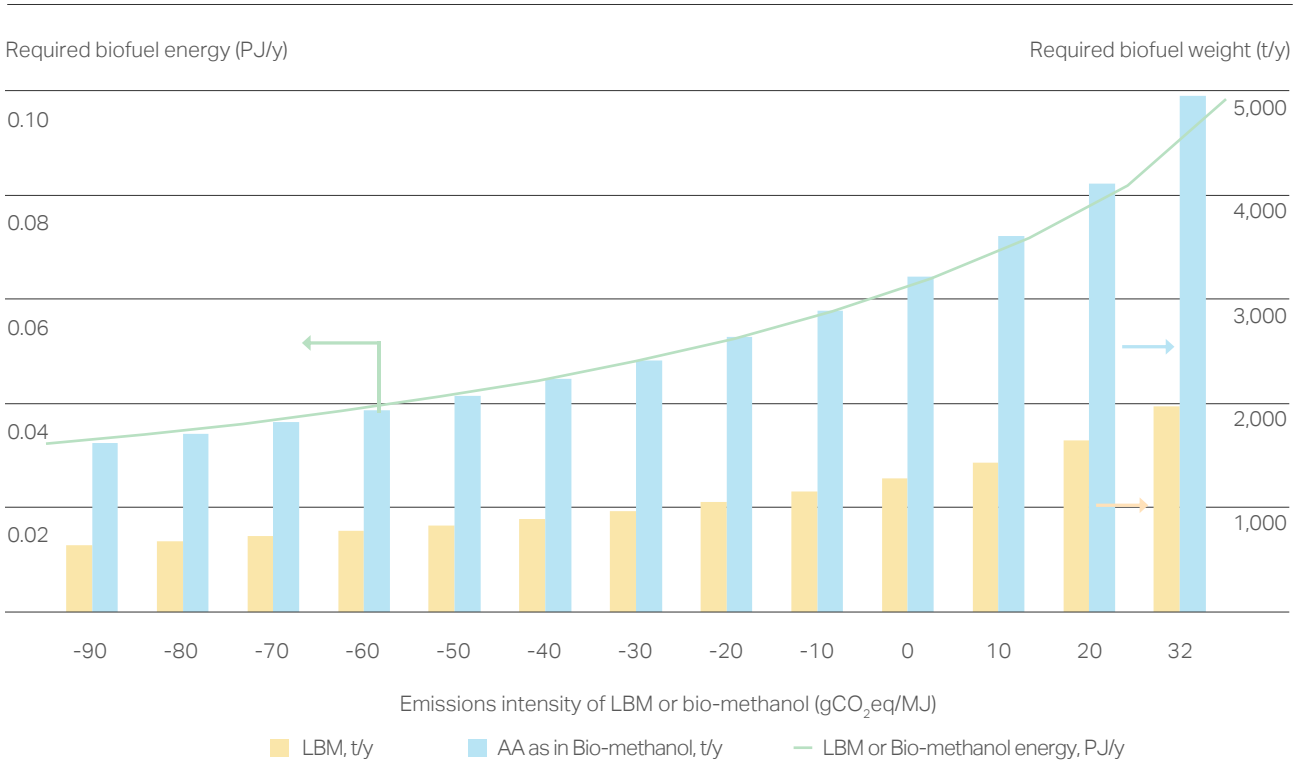


Figure 8 highlights that a shipping operator needs very little biofuel to comply with FuelEU in 2030 if the biofuel’s emissions intensity is strongly negative. If using a biofuel with an emissions intensity of -90 gCO₂eq/MJ or below, an operator needs less than one-third the weight of fuel compared to the requirement for the same biofuel with an emissions intensity of 32.9 gCO₂eq/MJ — the maximum emissions intensity for a biofuel to still be considered sustainable under RED II.

Such a large difference in requirements for compliance may play in favor of costs of compliance for a shipping operator in various ways:

1. Reducing the demand for biofuels for compliance. At the moment, the availability of biofuels is low;

reducing demand by improving the biofuels’ performance is a simple way to increase availability and reduce the risk of paying fines.

2. Reducing the procurement costs for bunkering, if the procurement price of biofuels is less sensitive to emissions intensity than weight or energy. It is hard to say if this is likely, as there is no commercial experience yet with pricing of biofuels depending on their certified emissions intensity.
3. Reducing the capital investments for revamp or newbuilds. Since FuelEU allows pooling of ships from the same or different fleets, being able to achieve the reduction target with less biofuel allows operators to concentrate carbon-free operations in fewer ships.



Considering the critical importance of emissions intensity for compliance strategy, we recommend that shipping operators consider whether selecting value chains rather than biofuels per se can generate economic opportunities. Investing in and acquiring the products of manufacturing projects and value chains yielding biofuels with minimal emissions intensity may be a useful strategy to lower the total costs of ownership. Choosing manufacturing projects can be a first step ("project first" approach) and a ship revamp or newbuild be decided afterwards based on the bio-fuel type and required amount, since the time to build chemical facilities is in the same order as the time required to build a ship.



4. Conclusion

This study reports on the performance of theoretical value chains based on biogas to supply shipping with LBM (liquefied bio-methane), fuel-grade bio-methanol, and AA bio-methanol fuels. The study, which was based largely on industrial knowledge shared by technology providers, investigated both commercially available technologies (the traditional route to bio-methane with liquefaction) and emerging advanced technologies that enhance the biofuel production process using green hydrogen. Our ambition was to achieve a qualitative understanding of the energy conversion efficiencies and the climate performance, in terms of WTW GHG emissions intensity, of the resulting biofuels.

We find that the standard commercial process to manufacture LBM has an overall attractive performance, both in terms of energy conversion efficiency and GHG emissions reduction potential. Particularly in situations where CCS can be implemented, commercial LBM manufacturing technologies can yield LBM with strongly negative WTW GHG emissions intensities. This is highly valuable for compliance with emissions reduction targets. Our analysis reveals that the biofuel energy needed for compliance with FuelEU Maritime can differ by a factor of 3 when comparing the most optimized value chain to the least optimized value chain — which seems very significant considering the cost and availability of biofuels. This is good news, as it offers the shipping industry a path to compliance with upcoming regulatory targets.

In general, we find that the climate performance of a biofuel does not depend much on the type of biofuel (i.e., LBM versus bio-methanol), but it is very strongly affected by the frame conditions of the manufacturing pathway and the related value chain. Within this study, the CCS potential seems particularly critical: we calculate that a manufacturing value chain of AA bio-methanol that can benefit from CCS (Pathway 6b) has a negative emissions intensity in the same range as that of the top-performing LBM with CCS pathway (Pathway 1a).

Advanced processes that enhance biogas conversion to biofuels using green hydrogen offer an alternative to maximize the biomass utilization at the price of high electricity consumption. These technologies are very attractive when a project has access to electrical power with zero or very low carbon burden and biomass availability is limited. On the contrary, if biomass comes with carbon credits — for example, for avoided methane emissions — then high biomass consumption has a beneficial effect on the emissions intensity of the resulting biofuel.

Our overall conclusion is that generalized calculations of the emissions intensity of a biofuel, such as the default GHG intensity values from RED II, may miss important opportunities or hide important sources of carbon emissions. Therefore, we do not recommend the use of such default values. Instead, the WTW GHG emissions of the manufacturing supply chain should be studied and developed for the specific asset. As the field is new, regulatory control is not yet optimal and fraud has been uncovered. Hence, reliance on independently certified supply chains is important to avoid paying high costs for no climate or compliance benefits.

As a result of this study, we encourage shipping operators to consider whether a “project first” approach can be beneficial to their business. By choosing and investing in optimized manufacturing projects, operators can control both supply and costs. Considering that the time to build a biofuel manufacturing facility is comparable to the time to build a new ship, the necessary modifications to the fleet and the business may be initiated once the supply of a high-value fuel is ensured.



5. 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 asterisk (*) were seconded to the MMMCZCS from partner organizations.

Lead author:

Roberta Cenni (MMMCZCS).

Contributing authors and project participants:

Joachim Jacobsen* (Topsoe), Siddharth Dwivedi* (Topsoe), Loic Francke* (TotalEnergies), Federica Conti* (Norden), Anker Jacobsen (Ammongas), Stephane Bosc (Ammongas), Alexander Ryhl (Ammongas), Thorkil Dahlgreen (BiogasClean), Jesper Hørlyk-Jensen (BiogasClean), Peter Thygesen (BiogasClean), Derya Topcu (E.ON), Michael Bruhn (E.ON), Rene Korsholm (E.ON), Anton Jell (Linde Engineering), Josef Schwarzhuber (Linde Engineering), Hugo Villalba (Novonosis, formerly Novozymes), Adrian Rochefort (Novonosis, formerly Novozymes), Einar Gudmundsson (Rambøll), Magnus Folkelid (Wärtsilä), Frank Hartevelde (Wärtsilä), Peter Jonathan Jameson (Boston Consulting Group), Maurice Jansen (Boston Consulting Group), Kevin Maloney (Boston Consulting Group), Ester Ceriani (MMMCZCS), and Harshil Desai (MMMCZCS).

Steering committee:

Jean Bernard (TotalEnergies), Keith Dawe (Cargill), Estela Vázquez Esmerode (MMMCZCS), Kim Grøn Knudsen (Topsoe), Torben Nørgaard (MMMCZCS), Henrik Røjel (Norden), and Maria Strandesen (Maersk).

Reviewers:

Torben Nørgaard (MMMCZCS) and Federica Conti* (Norden).

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Editors:

Matilda Handsley-Davis (MMMCZCS), Emily Nordvang (MMMCZCS), and Asha Mahadevan (MMMCZCS).

Design:

Tina Milosevic (By Milo).

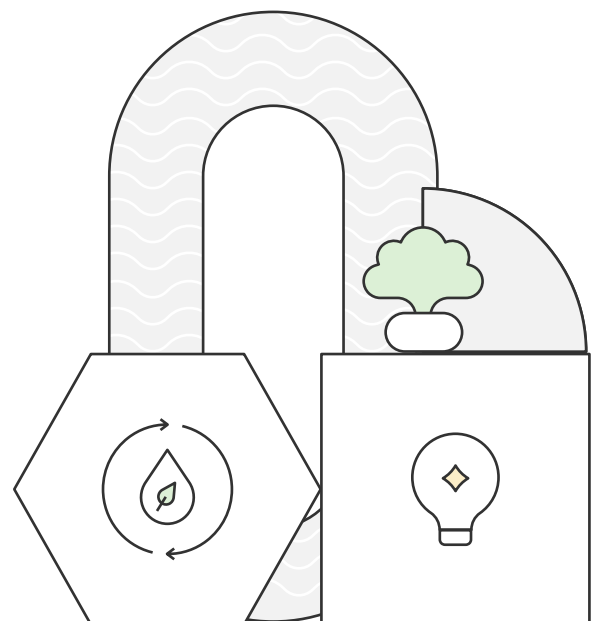


Abbreviations

AA	Grade AA (methanol specification)
AD	Anaerobic digester
AC	Activated carbon
BFW	Boiler feed water
Biofuel	A fuel generated from biomass: includes bio-methane, bio-methanol, bio-diesel (FAME), HVO, ethanol, and others
BioMeOH	Bio-methanol
BioMeOH1	Pathway for manufacture of bio-methanol based on traditional steam methane reforming
BioMeOH2	Pathways for manufacture of bio-methanol based on eREACT™
BioV	Biovilleuveois biogas plant
CCS	Carbon capture and storage
CH ₄	Methane
CH ₄ OH	Methanol
CO ₂	Carbon dioxide
CO ₂ eq	CO ₂ equivalent
eREACT™	Electrical steam methane reforming
EJ	Exa (1x10 ¹⁸) joule
FeCl ₃	Iron (III) chloride, also known as ferric chloride
FFC	Fossil Fuel Comparator
FG	Fuel-grade (methanol specification)
FuelEU	FuelEU Maritime Initiative
gCO ₂ eq/MJ	Grams of carbon dioxide equivalent per megajoule of energy
GHG	Greenhouse gas
GHGe	Greenhouse gas emissions
GLEC	Global Logistics Emissions Council
h	Hour
H ₂	Hydrogen
H ₂ O	Water
H ₂ S	Hydrogen sulfide
kg	kilogram
kTOE	Kilo (or thousands) tonnes of oil equivalent
LBM	Liquified biomethane, also known as liquified biogas (LBG) or bio-LNG
LHV	Lower heating value, also known as lower calorific value
LNG	Liquified natural gas
MJ	Mega (1x10 ⁶) joule
MMMCZCS	Mærsk Mc-Kinney Møller Center for Zero Carbon Shipping
Mt	Million (or mega) tonne
MTPA	Metric tons per annum
NM	Nautical mile (1,852 km)
Nm ³ /h	Normal cubic meter per hour
NPK	Nitrogen, phosphorus, potassium
O ₂	Oxygen
PEM	Proton-exchange membrane, or polymer-electrolyte membrane
PJ	Peta (1x10 ¹⁵) joule
ppm	parts per million
RED	Renewable Energy Directive of the European Union
SMR	Steam methane reforming



SNG	Synthetic natural gas: an almost pure stream of methane resulting from the catalytic or biological reaction of CO ₂ with hydrogen
SNG1	Pathway for SNG manufacture based on a catalytic process
SNG2	Pathway for SNG manufacture based on a biological process
SOEC	Solid oxide electrolyzer cells
t	tonne (also known as metric ton = 1,000 kg)
TJ	Tera (1x10 ¹²) joule
TOE	Tonnes of oil equivalent (calculated for lower heating value of 42.6 kg/MJ)
TRL	Technology readiness level
WTW	Well-to-wake
y	Year



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Appendix A: Additional methodological details

This appendix describes further details of the methods used in this study, including biogas production at BioV, options for scale-up strategies, and limitations of our analysis.

A.1 Bio-methane production at BioV

Figure 9 shows the consolidated energy and material flows for the BioV plant. Energy and material balances around the anaerobic digester vary due to the batch character of the process and the changing biomass composition. In our [insights into the value chain](#) report, we discuss the large variability of biomass in a loading plan and how methane yield depends on biomass type.

Figure 9 shows the main input streams (biomass – light green, electricity – light blue, diesel – grey, and chemicals – pink) and output streams (biofuel and digestate – dark green, fugitive emissions – light yellow, CO₂-containing streams – dark yellow) for anaerobic digestion.

Public information on BioV does not include the concentration of sulfur compounds, which are mostly present as hydrogen sulfide (H₂S). We have assumed that biogas contains 2,500 parts per million (ppm, here by volume) H₂S and that scavenging by ferric chloride (FeCl₃) can reduce this concentration down to 200 ppm. Further ‘polishing’ of the desulfurized biogas using activated carbon is required before further processing or releasing the stream into the atmosphere. Spent activated carbon must be regenerated or disposed of (not shown).

Electricity is required for biomass preparation (stream 1: cutting, crushing, conveying, etc.), mixing in the digester, air treatment of the collection rooms (stream 3), upgrading via membrane (stream 6) and compression for injection into the local grid (stream 5). Diesel is used

to transport biomass to the anaerobic digester (stream 1) and to return digestate to the fields and spread it (stream 4). At BioV, biomass (stream 1) is collected from the local region with an average radius of 15 km, and digestate resulting from the process (stream 11) is returned to fields located with an average radius of 17.5 km (including distribution).

CO₂ is released in a concentrated form both from the upgrader (after flaring of the residual CH₄) (stream 13) and from the combustion of biogas, which is required to support certain thermal needs such as pasteurization of manure and food waste. Both CO₂ and CH₄ can escape to the atmosphere at all processing stages if equipment is not tight and operations are not careful. Fugitive emissions from spreading manure directly onto the fields can be avoided if manure is processed in a biogas plant (stream 2), and this may constitute a carbon credit.

The biogas composition in the original BioV data was 61% CH₄/ 38% CO₂, which is not exactly as specified in our basis of design (52.4% CH₄/42.5% CO₂). To achieve the same composition as in the basis of design, the biomass plan and therefore the energy requirements for biomass transport and preparation would be somewhat different. However, since this energy is a small contribution to the total and the discrepancy affected all the manufacturing pathways we considered in almost the same way, we judged that the error was acceptable.

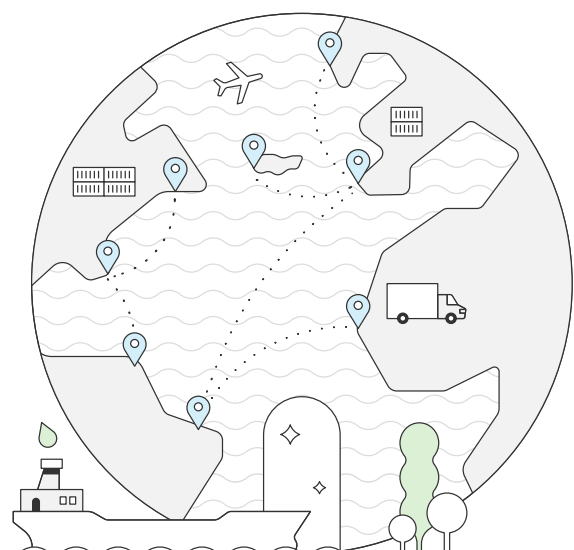
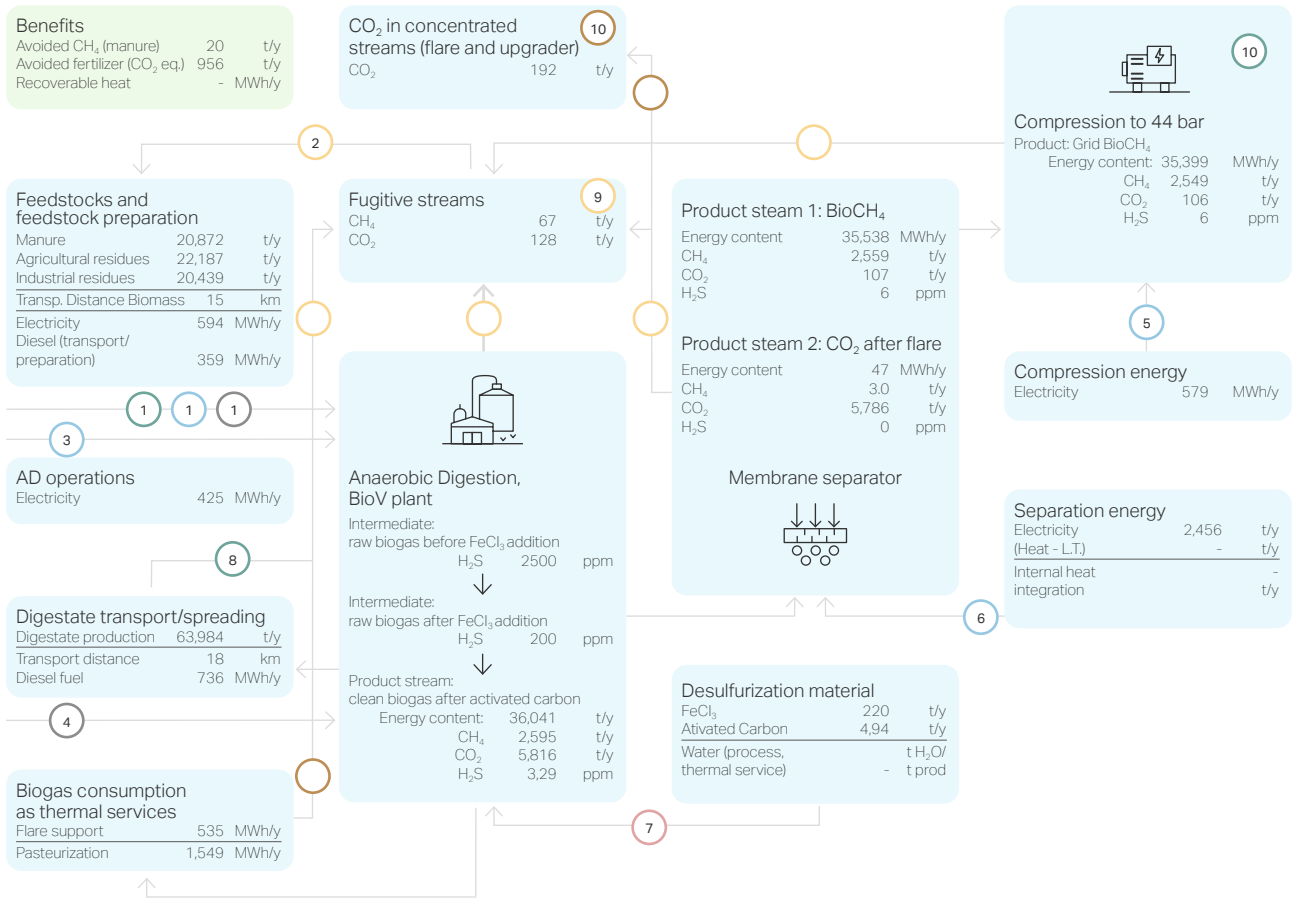


Figure 9: Energy and material flows associated with BioV, after data reconciliation by MMMCZCS. (Note: streams 8 and 9 are intentionally not shown in this figure but formed part of a larger background dataset.)



A.2 Scale-up strategies

Economies of scale encourage the construction of large-scale plants, and this is particularly true for catalytic synthesis, liquefaction, and biogas upgrading. As there are limits to the size of an individual anaerobic digester, large plants typically comprise several digesters combined in series and/or in parallel. We therefore assumed that the energy and material flows of large biogas plants can be modeled as multiples of a small plant.

Since maintenance at one reactor does not preclude the operation of other reactors at the same plant, the

availability of systems with multiple parallel reactors tends to be high. We have considered 8,400 h/y (~96%), typical of chemical plants, in line with the availability for upgrading, syntheses, liquefaction, etc.

Table 2 and Table 3 previously highlighted the suitability of relevant technologies with respect to plant capacity. In our scale-up exercise, we introduced technologies relevant to the desired plant scale for upgrading, sulfur removal, and liquefaction. We identified three possible aggregation scenarios to allow scale-up, summarized in Figure 10.

Figure 10: Scale-up options for biogas production. (1) Small, decentralized plants, each comprising an anaerobic digester and an upgrader, feed into the natural gas pipeline network. Bio-methane for further synthesis and/or liquefaction is pulled from the network. (2) Small, decentralized plants comprising an anaerobic digester feed biogas to a centralized upgrading/synthesis/liquefaction plant via a biogas distribution network. (3) A large plant comprising an anaerobic digester and an upgrading/synthesis/liquefaction plant collects biomass from a larger area.



A.2.1 Connection of multiple decentralized small biogas/upgrading plants via the natural gas network

The first scale-up option we considered was to build larger capacity by connecting multiple plants of the same capacity (Figure 10 panel (1)). Physically, this can be done by aggregating bio-methane if each anaerobic digester has its own upgrader. This approach leverages the natural gas network as represented by pathways (15), (16), (18), and (22) in Figure 2. Further processing, such as liquefaction or methanol manufacture, pulls the gas from the natural gas network. Existing commercial examples of this practice are outlined in Table 2 of our companion report on [insights into the value chain](#).

To model the energy and material flows of this scale-up scenario, we have used data from BioV multiplied by the appropriate number of plants to give the desired production capacity. We have disregarded the energy loss from transport via the natural gas pipeline network associated with pressure drop. This energy loss depends upon pipeline length and amounts to approximately 0.11 – 0.12 bar/km*, which we have considered negligible. However, we have accounted for the methane losses in the pipeline network, as described in our report on fugitive emissions. We only modeled LBM pathways in this scale-up scenario, as we did not have data for the bio-methanol pathways.

A.2.2 Connection of multiple small biogas plants with a centralized upgrader via a biogas network

Large capacity may also be obtained by aggregating the biogas after dewatering (Figure 10, panel (2)) and processing the biogas in a centralized synthesis/liquefaction plant (Figure 2, pathways (12), (13), (14), (22)) or in a centralized upgrader (Figure 2, pathways (12), (13), (16), (18), (22)).

We have modeled these cases using BioV as the reference plant for the anaerobic digestion portion and amine scrubbing + biologic desulfurization for the upgrading portion of the pathway. In practice, biogas is aggregated in some individual production plants (see Section 2.2.2 in our report on [insights into the](#)

[value chain](#)), but the 'biogas network' is still mostly conceptual. Similar to the first scale-up approach, we do not expect biogas collection via the biogas network to have a significant impact on energy and material flows. However, there is an impact on capital expenditures if that infrastructure must be built; this scenario is explored further in our companion report on [techno-economic trends](#).

A.2.3 Biomass amassment in a large-capacity plant

As a third option, large production capacity can be achieved with a single, centralized anaerobic digestion plant that is operated with biomass collected from a larger area (Figure 10, panel (3)) and connected to its own large-scale upgrading/synthesis/liquefaction units. This strategy is already practiced commercially.

In terms of relative energy consumption, the key difference with respect to the previous options is the larger amount of diesel needed to collect biomass and return digestate to the farms. Our model of this scale-up option used data from BioV to estimate the areal density for feedstock and digestate return (for feedstock: 60,000 t feedstock collected from an average distance of 15 km is approximately 85 t/km²; for digestate: 60,000 t returned to an average radius of 17.5 km (as in BioV) is approximately 63 t/km²). For a 10,000 Nm³/h plant, the average feedstock collection distance becomes 53 km and average digestate return distance becomes 63 km. The energy required for transport was calculated using the Global Logistics Emissions Council (GLEC) model for a rigid truck with 1,000 deadweight tonnage.³⁵

In practice, large plants typically source low-yield and low-cost feedstocks from local areas and transport mainly high-yield feedstocks. This is a good strategy to reduce both the cost and the energy intensity associated with transport.

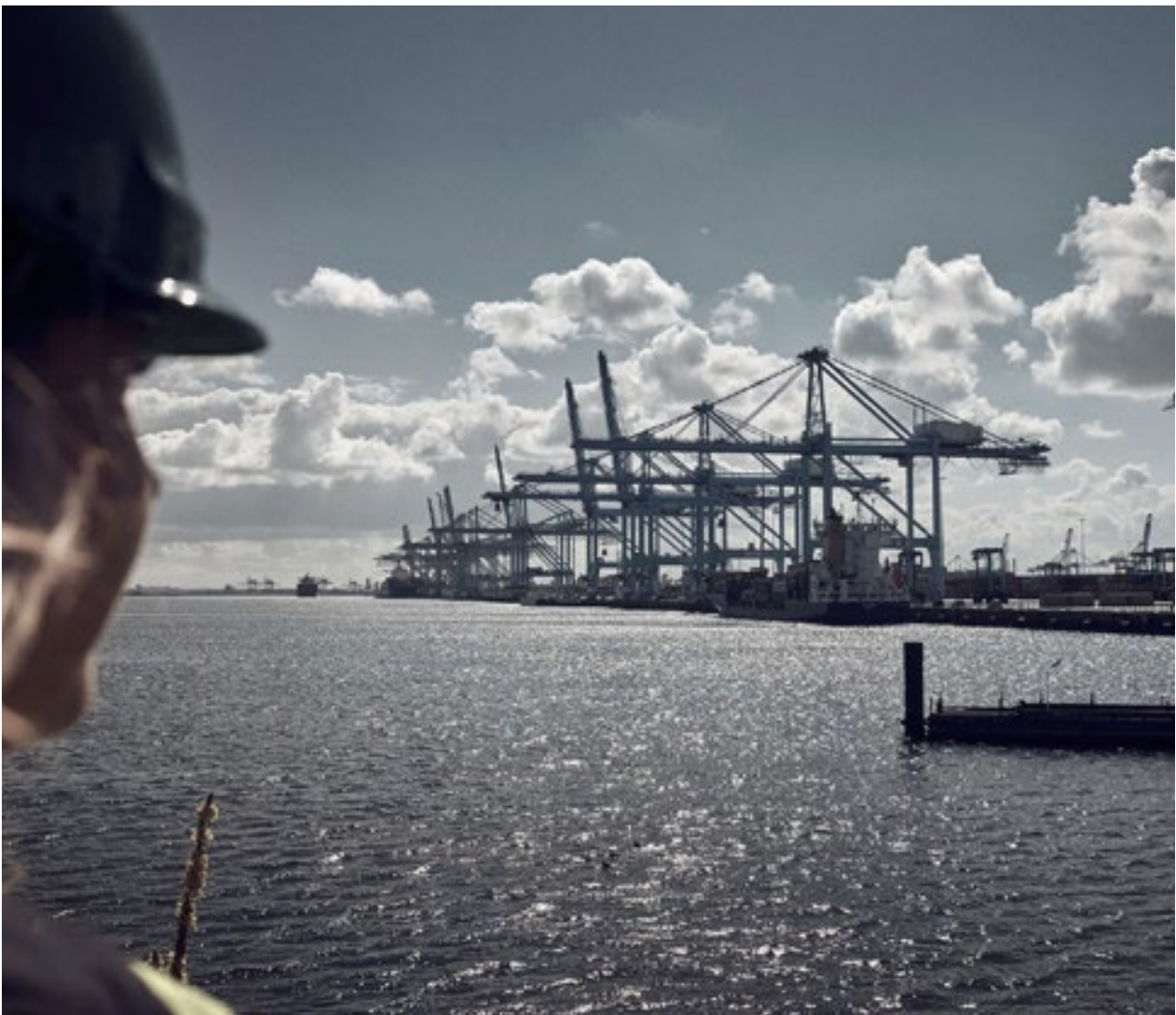
*~0.11-0.12 bar/km – calculated from public information.^{36,37}



A.3 Limitations of this study

As previously described, process licensors provided energy and material streams for individual licensed units. MMMCZCS personnel studied combinations of units and the integration of streams to create full pathways. Important assumptions made during this consolidation work were:

1. Modification of the biogas composition at the exit of the anaerobic digester (see Appendix A, Section A.1).
2. Adaptation of desulfurization to the catalytic syntheses.
3. Introduction of oxygen removal prior to catalytic syntheses: we assumed hydrogen combustion (based on guidance from technology providers) and calculated hydrogen demand via mass balances. The heat of this reaction was not integrated in the technology package.
4. Modeling of electrolysis for Pathway 3.
5. Addition of CCS to Pathways 1 and 6.
6. Partial heat integration between different technology packages.
7. Transport distances for biofuels to ports: we used arbitrary distances of 1,000 NM by ship and 50 km by truck and estimated diesel consumption using specific consumption data from GLEC.³⁵



Appendix B: Decarbonization potential of a production asset

As the nine biofuel production pathways we considered have different production rates, we wanted to see how value chains compared with each other in terms of total decarbonization potential. This value is obtained as the yearly production capacity of the value chain (in terms of biofuel energy) multiplied by the difference between the emissions intensity of a fossil fuel comparator and the biofuel. The calculation uses the following equation:

$$\text{Value chain decarbonization potential} = E_B \times (EI_F - EI_B)$$

Where:

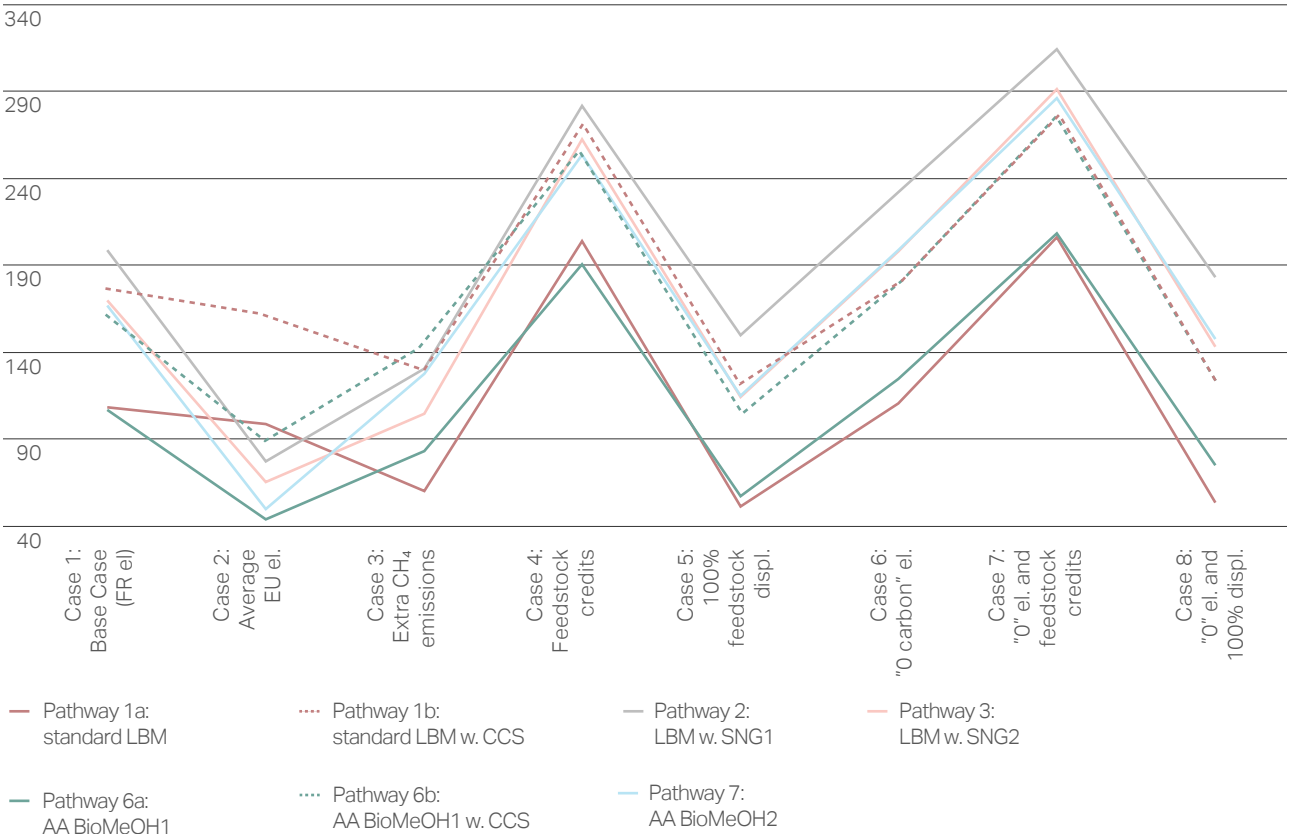
E_B	biofuel
EI	emissions intensity in $gCO_2eq/MJ = kgCO_2eq/GJ = ktCO_2eq/PJ$
E	yearly energy in PJ/y
E_F	fossil marine fuel (EI as in the fossil fuel comparator)

Since all pathways in our study were analyzed using similar biomass input, the comparison indicates how well each pathway can use the biomass for overall decarbonization purposes. The parameter is not of particular interest to biofuel users, but it is interesting from the point of view of optimizing the use of available biomass — a topic that is expected to increase in importance as demand for biomass grows.

Figure 11 summarizes the decarbonization potential for our selected pathways based on the same calculation cases described in Table 7.

Figure 11: Value chain decarbonization potential for selected biofuel production pathways and calculation cases as detailed in Table 7.

Value chain decarbonization potential (kt CO₂eq/y)



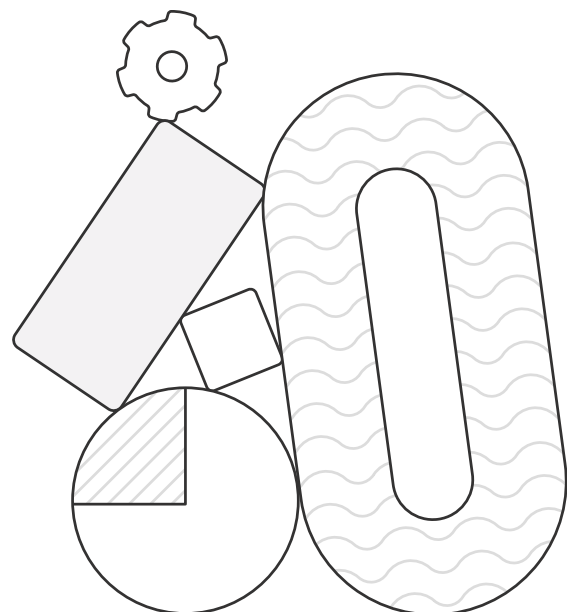
Based on these results, we can see that: Pathways 1a and 6a (maroon and green solid lines) do not perform well in terms of total decarbonization potential — their production rate is low and is coupled with average emissions intensity. The sole exception is Case 2, when electricity is largely non-renewable, as in the EU mix. Here, Pathway 1a turns out to be the best option if CCS is not available, due to the high emissions from electricity consumption in all other pathways. However, Pathway 1a in Case 2 delivers only around 100 kt CO₂eq/y of decarbonization potential.

The two CCS pathways (1b and 6b, maroon and green dashed lines) perform very well in most cases, even accounting for their low production rate. If electricity is not fully decarbonized (Cases 1-5), these two pathways rank at the top or close to the top.

Pathway 2 (SNG1, blue solid line) compensates for the relatively high emissions intensity of its product with a very high production rate and shows the overall best performances in most calculation cases (except Cases 2 and 3) — as long as electricity has an emissions burden equivalent to or lower than that of the French mix (base case).

Pathway 3 (SNG2, pink solid line) and Pathway 7 (BioMeOH2, pale blue solid line) also compensate for average emissions intensities with high production rates and show similar decarbonization potential as the CCS pathways, except in Cases 2 and 3.

These results show strong potential for advanced biofuels when they can rely on low-carbon electricity. However, due to the emissions associated with construction and maintenance, even renewable electricity based on solar or wind energy does not truly have a carbon burden of zero, even though certain regulatory frameworks such as RED II currently accept this “0” value. As the world decarbonizes, these contributions will become less and less, but this is not the situation today. Particularly if carbon-neutral electricity is obtained via a Power Purchasing Agreement, it is important to ensure that double counting is not taking place and that the carbon burden of the electricity is certified.





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