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DENMARK

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Dissertation submitted

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Copenhagen, February 2021

Andrei David Korberg

ENGLISH SUMMARY

Future energy systems will require the efficient use of all available renewable resources. This thesis aims to integrate efficiency with renewable fuel pathways for those sectors that will still require gaseous or liquid fuels, namely: stationary units for power and heat production, industrial demands, heavy-duty long-distance road transport, shipping and aviation. Despite the immense potential for electrification in all these sectors, the production of renewable fuels remains necessary. A wide variety of potential solutions exists for each of these sectors, making it difficult to choose suitable renewable fuels and pathways. To facilitate the choice, this thesis aims to identify feasible renewable fuel production pathways that can form part of future sustainable energy systems and examine their comparative efficiency.

The thesis uses a feasibility study approach based on advanced energy system analysis and techno-economic assessments presented in three peer-reviewed research articles. Four theoretical concepts guide the recommendations: Value chains, the Energy Efficiency First principle, Smart Energy Systems and Choice Awareness theory.

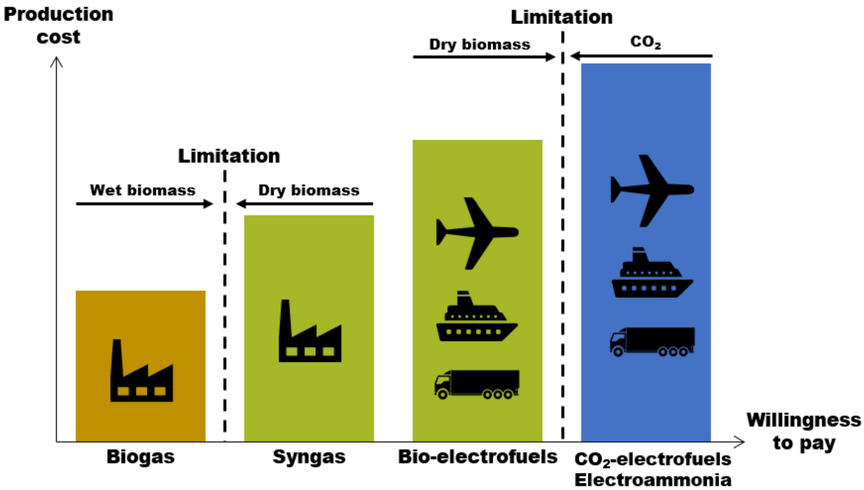
The first results discussed concern the choice of renewable fuels in stationary applications. Despite increases in wind and solar generation capacity, future energy systems will continue to require gas in power plants to balance the energy system. Raw biogas and biogas-derived biomethane should be prioritised for this task since they can minimise dry biomass consumption and drive down energy system costs; however, they are limited by farming practices. Syngas from biomass gasification should supplement biogas in the same applications, despite the potentially higher dry biomass feedstock price. However, the upgrade of syngas to methane quality, with or without electrolytic hydrogen, increases production costs and decreases the system efficiency.

The next area addressed is the choice of renewable fuels in transport. Syngas from biomass gasification may also be combined with hydrogen from electrolysis to produce liquid bio-electrofuels in a cost-efficient manner. The dual role of thermal gasification calls for a careful balancing between supplying gas and supplying liquid fuels. CO_2-electrofuels, a combination of electrolytic hydrogen and carbon capture and utilisation, can supplement bio-electrofuels, but the availability of reliable carbon sources may limit them. Furthermore, while they do not consume biomass directly, their use results in a higher overall biomass consumption since power plants operate more often.

Independent of the type of fuel production pathway utilised, methanol end-fuel is recommended in heavy-duty long-distance transport, while methanol and Fischer-Tropsch liquids are competitive in aviation. The shipping sector is examined in more detail in this thesis, and from a total cost of ownership perspective, methanol still

emerges as the lowest cost solution due to the simplicity of storage, bunkering infrastructure, propulsion system, and low production costs. Ammonia and DME are only marginally more expensive than methanol despite the more complex propulsion, storage and infrastructure requirements.

The combined results of the three research articles highlight the feasibility of four renewable fuel production pathways that can be integrated into the design of future sustainable energy systems. Electrofuels will remain an expensive alternative since they are dependent on electricity prices and cannot be expected to suit all purposes in a cost- and energy-efficient manner. Biogas and syngas are more suited to electricity or heat markets, where the alternatives are limited and driven by low-cost renewable electricity or heat producers. Thus, as illustrated in the graphical abstract, the design of renewable fuel pathways can ensure the efficient use of all renewable resources by aligning production costs to the willingness to pay, paving the way for the future uptake of fuels.



DANSK RESUMÉ

Fremtidige energisystemer kræver en effektiv udnyttelse af alle tilgængelige vedvarende ressourcer. Denne afhandling har som mål at integrere effektivitet i vedvarende brændselsløsninger for de sektorer, som stadig har brug for gas eller flydende brændstof: stationære enheder til el- og varmeproduktion, industrielt forbrug, tung langturstransport, sø- og luftfart. Trods det store potentiale for elektrificering i alle disse sektorer, vil der fortsat være et behov for at producere vedvarende brændsler. Der findes dog en lang række potentielle løsninger, som gør det svært at vælge de rette vedvarende brændsler og den rette vej frem. For at gøre dette valg lettere, kortlægger denne afhandling de mulige veje til vedvarende brændselsproduktion, som kan integreres med fremtidige bæredygtige energisystemer og undersøger deres sammenlignelige effektivitet.

Afhandlingen tager sit afsæt i et feasibility study baseret på avanceret energisystemanalyse og en teknisk-økonomisk vurdering beskrevet i tre fagfællebedømte videnskabelige artikler. Anbefalingerne er baseret på fire teoretiske koncepter: Værdikæder, Energieffektivitet med udgangspunkt i Energy Efficiency First-princippet, Intelligente energisystemer og Teorien om det bevidste valg (Choice Awareness).

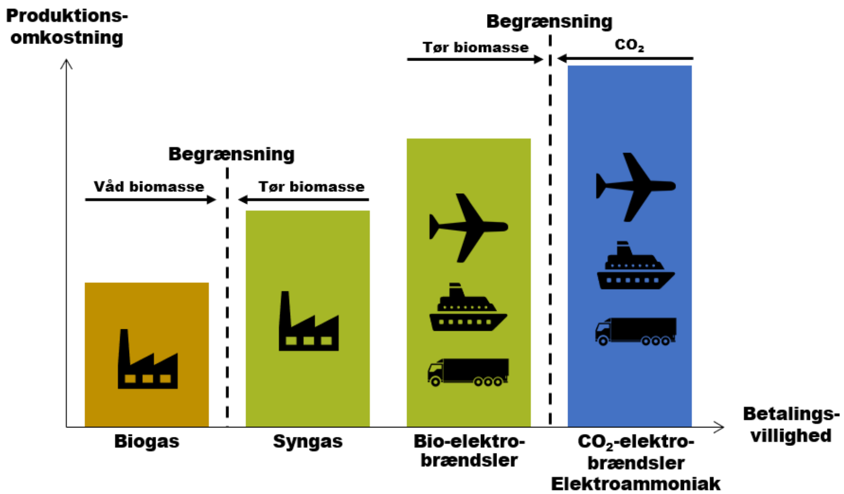
Første del af resultaterne omhandler valget af vedvarende brændsler til stationære enheder. På trods af øget vindkraft- og solenergiproduktion vil der i fremtiden fortsat være brug for gas i kraftværker til balancering af energisystemet. Rå biogas og biometan af opgraderet biogas bør prioriteres til dette formål, fordi de kan minimere forbruget af tør biomasse og sænke systemudgifterne til energi; dog er de begrænset af landbrugspraksis. Syngas fra biomasseforgasning bør supplere biogas i de samme applikationer, på trods af den potentielt højere pris på tør biomasse. Dog øger opgraderingen af syngas til metankvalitet, med eller uden elektrolytisk hydrogenering, produktionsomkostningerne og sænker systemeffektiviteten.

Anden del af resultaterne omhandler valget af vedvarende brændsler til transport. Syngas fra biomasseforgasning kan også kombineres med brint fra elektrolyse i en omkostningseffektiv produktion af flydende bio-elektrobrændsler. Termisk forgasning får dermed en dobbeltrolle, som kræver en omhyggelig afbalancering mellem forsyningen af hhv. gas og flydende brændsler. CO_2-elektrobrændsler, en kombination af elektrolytisk brint og CO_2-fangst og anvendelse, kan supplere bio-elektrobrændsler, men kan være begrænset af tilgængeligheden af pålidelige CO_2-kilder. Selvom disse ikke har et direkte forbrug af biomasse, resulterer de generelt i et højere biomasseforbrug, fordi de kræver at kraftværkerne oftere skal være i drift.

Uafhængigt af den valgte type af brændselsproduktion, anbefales metanol som endeligt brændstof til tung langturstransport, mens metanol og Fischer-Tropsch

flydende brændsel er konkurrencedygtigt som flybrændstof. I denne afhandling analyseres søfart mere detaljeret, og set i forhold til den samlede omkostning ved ejerskab, vil metanol stadig være den billigste løsning. Dette skyldes metanols simple lagring, infrastruktur til opbevaring, system til fremdrift og lave produktionsomkostninger. Ammoniak og DME har marginalt højere samlede omkostninger på trods af deres mere komplekse fremdrift, lagring og krav til infrastruktur.

Som et samlet resultat af de tre videnskabelige artikler fremhæves fire mulige veje til vedvarende brændselsproduktion, som kan integreres i udformningen af fremtidige bæredygtige energisystemer. Elektrobrændsler vil fortsat være dyre, da de afhænger af elpriserne og ikke forventes at kunne dække alle formål på en omkostnings- og energieffektiv måde. Biogas og syngas er mest anvendelige på el- eller varmemarkeder, hvor alternativerne er begrænsede og er drevet af billig vedvarende el- eller varmeproduktion. Som grafikken illustrerer, kan udformningen af vedvarende brændselsløsninger således sikre en effektiv udnyttelse af alle vedvarende ressourcer ved at matche produktionsomkostningerne med betalingsvilligheden - og kan således bane vej for en fremtidig brændstofoptagelse.



PUBLICATION LIST

This dissertation is based on a collection of three peer-reviewed research articles. The studies are part of Chapter 6 of this dissertation. These are referenced as Study 1, Study 2 and Study 3.

- Study 1: Korberg AD, Skov IR, Mathiesen BV. *The role of biogas and biogas-derived fuels in a 100% renewable energy system in Denmark*. Energy 2020;199. https://doi.org/10.1016/j.energy.2020.117426 [1]

- Study 2: Korberg AD, Mathiesen BV, Clausen LR, Skov IR. *The role of biomass gasification in low-carbon energy and transport systems*. Smart Energy. Accepted 2021 [2]

- Study 3: Korberg AD, Brynolf S, Grahn M, Skov IR. *Techno-economic assessment of advanced fuels and propulsion systems in future fossil-free ships*. Renew Sustain Energy Rev 2021. In Press. https://doi.org/10.1016/j.rser.2021.110861 [3]

Secondary literature, publicly available reports, but not included in the dissertation:

- Sorknæs P, Korberg AD, Johannsen RM, Petersen UR, Mathiesen BV. *Renewable based Energy System with P2H and P2G*. Aalborg: 2020 [4]

- Skov IR, Korberg AD, Mathiesen BV, Sorknæs P. *Biogas utilisation in the energy system and market potential for biogas methanation*. Copenhagen: 2019 [5]

- Paardekooper S, Lund RS, Mathiesen BV, Chang M, Petersen UR, Grundahl L, et al. *Heat Roadmap Europe 4: Quantifying the Impact of Low-carbon Heating and Cooling Roadmaps*. Copenhagen: 2018 [6]

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LIST OF ABBREVIATIONS

AEL – Alkaline electrolysis

ASU – Air separation unit

CCGT – Combined cycle gas turbine

CC – Carbon capture

CCS – Carbon capture and storage

CCU – Carbon capture and utilisation

CHP – Combined heat and power

CMG – Compressed methane gas

DAC – Direct air capture

DME – Dimethyl ether

EU28 – European Union 28-member states

FC – Fuel cell

FT – Fischer Tropsch

GHG – Greenhouse gas

GTL – Gas-to-liquid

HEFA - Hydroprocessed esters and fatty acids

HTL – Hydrothermal liquefaction

HVO – Hydrotreated vegetable oil

ICE – Internal combustion engine

LCOE – Levelized cost of electricity

LH_2 – Liquefied hydrogen

LMG – Liquefied methane gas

LPG – Liquefied petroleum gas

MGO – Marine gas oil

NIMBY – Not in my back yard

PEMEL – Polymer (proton) exchange membrane electrolysis

PEMFC – Polymer (proton) exchange membrane fuel cell

POX – Partial oxidation

PtH – Power-to-Heat

PtL – Power-to-Liquids

PtM – Power-to-Methane

SMR – Steam methane reforming

SOEL – Solid-oxide electrolysis

SOEC – Solid-oxide fuel cell

STP – Standard temperature and pressure

VRES – Variable renewable energy sources

1 INTRODUCTION

There is a broad scientific consensus that the level of greenhouse gas (GHG) emissions have been increasing since the beginning of the Industrial Revolution. The effects of this increase are reflected in the accelerated warming of our plant, entailing devastating effects on the environment, economies and life on Earth. In 2015, at the COP21 in Paris, world leaders agreed to take swift action to have a chance to mitigate the increase in GHG emissions in order to limit average temperature increases to 2°C. However, the agreement has been criticised for its non-binding nature, and in the years following the agreement, few actions were taken, while GHG emissions continued to increase. Recently, an IPCC report [7] reiterated that urgent action needs to be taken before 2030 for there to be a chance of limiting the temperature increase before it reaches the tipping point:

> "Avoiding overshoot and reliance on future large-scale deployment of carbon dioxide removal can only be achieved if global CO_2 emissions start to decline well before 2030 (high confidence)" (Page 18, [7])

Anthropogenic emissions are the largest contributor to overall GHG emissions, with around 54-75 gigatons coming from human-induced activities, while natural systems produce 18-39 gigatons (2016 value). With average natural carbon sinks of 14-26 Gt, it is clear that the human-caused emissions are putting extra pressure on what is otherwise a self-balancing system [8]. Among the global anthropogenic emissions, more than 70% come from the energy sector, including energy used in buildings, industry and transportation [9]. In the European Union (EU), the share of emissions is similar to the global average, with 78% of emissions coming from fuel combustion and transport [10].

1.1 SOLUTIONS FOR DECARBONISING ENERGY SYSTEMS

The EU has recently set new GHG emissions reduction targets as part of a more comprehensive plan, the European Green Deal [11], which aims to make the EU economy more sustainable and competitive. In this action plan, the goal is to achieve climate-neutrality by 2050, which means that no new net emissions should occur apart from those that can be handled by carbon sinks. As part of this plan, the European Commission proposed raising the GHG emissions reduction goal from the previous target of 40% to 55-60% by 2030 [12] to speed the transition to climate neutrality.

Fundamental to accelerating the transition is the strategy of focusing on "low-hanging fruits" [13], i.e. solutions within reach that can bring the largest gains using available technologies. Significant progress can be made by 2030, but the implementation must have a long-term vision as the foundations of future energy systems must be laid down today. Energy infrastructures have long lifetimes, and today's decisions affect how the energy system will look in 2050. A handful of solutions can be considered "low-hanging fruits", bringing significant gains in the energy sectors with the highest fuel consumption and CO_2 emission: electricity, heating (and cooling) and transport.

First, the deployment of large-scale variable renewable energy sources (VRES), such as wind and solar, is widely accepted as a leading solution that will directly replace fossil fuels. The levelized cost of electricity (LCOE) for large solar installations has decreased by at least 82% in the past 11 years, while those for onshore and offshore wind installations have seen reductions of 39% and 29%, respectively [14], making wind and solar significantly lower cost per unit of energy produced than other emission-free technologies, such as nuclear [15]. VRES also enables the electrification of other parts of the energy system through cross-sector integration. Therefore, the recently adopted EU offshore strategy entails the deployment of 300 GW of offshore wind capacity by 2050 [16].

The potential for CO_2 emission reduction is higher for the heating and cooling sector than for electricity, as it is the largest energy consumer in the EU at over 50% of final energy demand [6]. District heating has been proposed as a primary solution to recycle heat that would otherwise be wasted while integrating large amounts of VRES [6,17]. District heating can enable cross-sector integration through combined heat and power (CHP) plants and heat pumps. Also known as Power-to-Heat (PtH) solutions, heat pumps can increase energy system efficiency through the electrification of the heating and cooling sector. Heat pumps are suitable both in district heating systems [18] and as individual solutions.

Another "low-hanging fruit" is the electrification of the transport sector, which is another form of cross-sector integration and a method to increase the energy system's efficiency. In the EU, a quarter of CO_2 emissions originate from transport, and 50% of these from cars or light-duty vehicles [19]. These transportation types also happen to be the most suitable for battery electrification. The widespread implementation of this technology is crucial as the average personal electric vehicle is about 3-4 times more energy-efficient than one powered by an internal combustion engine [20]. Other transport types can also be electrified successfully, such as rail transport, city busses and some heavy-duty transport and machinery.

The electrification of more parts of the energy system is an indispensable method for reducing fuel demand and emissions. The conversion of electricity to heat or to electromobility comes with high energy system efficiencies. In the race towards energy system decarbonisation, all sectors must eventually reduce and further eliminate fossil fuels. Implementing district heating solutions, CHP, and heat pumps and electrifying large parts of the transport sector can accomplish, to a large extent, the transition towards renewable energy systems. However, there will still be substantial uses of fossil fuels in various parts of the energy system that are not suitable for direct or battery electrification. The most significant are heavy-duty long-distance transport, deep-sea shipping, long-haul aviation, industrial processes that cannot be electrified or power and heat plants. For these cases, high-density renewable fuels will be a requirement, which is the focus of this dissertation.

1.2 INTRODUCTION TO RENEWABLE FUELS

Renewable fuels, as the name suggests, are fuels produced primarily from renewable energy sources and feedstocks. They can be either solid, liquid or gaseous. Solid fuels comprise all types of biomass that can be used directly as end-fuel in combustion processes. Liquid and gaseous fuels are more common than solid fuels since they can be used in more applications. The interest in producing and using renewable fuels stems from the fact that these can replace fossil fuels in all their potential applications, yet their emissions do not contribute to the accumulation of CO_2 in the atmosphere. While the vast majority of renewable fuels produce CO_2 emissions upon the utilisation of their energy content, they are assumed to have zero net GHG emissions [21].

The term "renewable fuels" can be relatively extensive, but Ridjan et al. [21] argue that the word "renewable" should only be associated with fuels produced from renewable feedstocks and electricity. In this regard, nuclear electricity is not considered renewable. Renewable fuels can be of two categories: *synthetic fuels* and *electrofuels,* which differ significantly in the production process and have different impacts on the energy system. Renewable synthetic fuels primarily utilise biomass in the production process and generally include the prefix "bio", e.g., biogas, biomethane and biomethanol. Renewable electrofuels use renewable electricity in the production process; therefore, they generally feature the prefix "electro", as in electromethane or electrodiesel. Utilising electricity to produce chemical energy is another type of cross-sectoral integration, and the products are often termed PtX fuels, where the "X" stands for the output fuel, such as Power-to-Methane (PtM) or Power-to-Liquids (PtL).

In turn, electrofuels are split into bio-electrofuels and CO_2-electrofuels. Both use renewable electricity as feedstock, but bio-electrofuels combine it with biomass conversion processes, while CO_2-electrofuels combine it with a source of carbon of biogenic or non-biogenic origin. Non-biogenic carbon is recycled from cement production, the waste-processing gas of various carbon emitters, or the atmosphere, but this does not include fossil fuel source emitters. Due to the closed carbon loop of non-biogenic sources, these fuels are considered renewable, just as biogenic fuels are.

Biofuels can be divided into two generations. The first generation of biofuels includes well-known processes, such as the fermentation of corn or wheat to produce ethanol and the esterification of vegetable oils to produce biodiesel. While these fuel production pathways produce drop-in fuels that can complement or replace fossil fuels, they are difficult to scale up since they rely on the same feedstock as food production while also taking away arable land that can be used for food growth. For this reason, such biofuels are not considered a sustainable large-scale solution [22].

The second generation of biofuels does not use feedstocks or land used for food production but instead relies on residues from agriculture and forestry, energy crops, sewage sludge, and the organic fraction of municipal solid waste, and micro-algae. Biomass conversion processes involved in the manufacture of second-generation biofuels include anaerobic digestion, gasification, hydrothermal liquefaction, pyrolysis and fermentation, producing both liquid and gaseous fuels [22]. Such biofuels have a higher potential for up-scaling than first-generation biofuels but are still limited by biomass resources availability.

Bio-electrofuels offer the possibility of utilising fewer biomass resources than biofuels by increasing production yields. Electrolytic hydrogen is combined with the carbon in biomass via electrolysis, which uses water and renewable electricity as inputs. Electrolysers come in various technologies, from low-temperature systems, such as alkaline or polymer membrane electrolysis, to high-temperature systems, such as solid-oxide electrolysis. The produced hydrogen is combined with the CO_2 in biomass to increase the production yield, unlike biofuel production processes, where the CO_2 is separated and removed. Not all biomass conversion pathways can integrate hydrogenation to increase yields, but some pathways, like anaerobic digestion and biomass gasification, show particular potential for hydrogenation and increased production yields.

CO_2-electrofuels are distinguished from bio-electrofuels by the use of different production technology. The main difference is the use of carbon capture instead of biomass conversion. Carbon capture technologies recover carbon from emitters or capture it from the air, concentrating it into a CO_2 stream that can be used as input for fuel production. A variety of carbon capture technologies exist, but only a few have shown commercial potential [23]. The carbon streams combine with electrolytic hydrogen to produce various fuels, as with biofuels and bio-electrofuels.

As an extension to CO_2-electrofuels, the carbon atoms can also be replaced with nitrogen. Nitrogen is the most abundant component in the air and can be captured using air separation units (ASU) that split the air into its core components. The nitrogen can be combined with electrolytic hydrogen in a fuel synthesis to produce ammonia. Ammonia can also be produced starting from biomass gasification by combining the hydrogen and nitrogen within syngas with nitrogen from ASU. However, this thesis only includes the pathway originating from electrolytic hydrogen, hence the name electroammonia.

The fuels included through the analyses can vary from simple molecules, such as methanol or methane, to more complex structures comparable to today's refined fossil fuels, such as petrol, diesel or jet fuel. Hydrogen is often promoted as an alternative solution to electrofuels since it does not produce any emissions, and in this analysis, it is considered a standalone fuel in its category.

1.3 THE FEASIBILITY OF RENEWABLE FUELS SO FAR

The research to date has demonstrated the feasibility of renewable fuels in future energy systems. The term "feasibility" is central, and it entails that the existing research has already found renewable fuels to be feasible after accounting for their technical, economic, social and environmental factors. There is a consensus that such energy-dense fuels will be needed to replace fossil fuels and eventually reach carbon neutrality or 100% renewable energy systems. This chapter includes a literature review of some of the most relevant studies that identify different renewable fuels for future energy systems, ranging from biofuels to various electrofuels and hydrogen. Some studies analysed the potential of these fuels in all energy system sectors, while others only studied the transport sector. Although the authors of the studies below also investigated the potential for electrification, the focus remains on the renewable fuels they identify.

In their global assessment, Jacobson et al. [24,25] find that hydrogen would be a suitable fuel in all energy sectors in fuel cells and combustion, although biofuels are not recommended as they negatively impact the energy system. This view is shared by Moriarty et al. [26], who claim that biomass should only be available for specialised uses in transport, and the production of food and biomaterials should be prioritised over the production of biofuels. However, Ahlgren et al. [27] find that the market penetration of biofuels in global energy systems is low to medium at 10-40%, but that their market penetration can be increased if biofuels are combined with bio-electrofuels. Caspeta et al. [28] argue that biofuels can make an essential contribution to the future energy system despite the arguments related to their competition with food, cost and sustainability.

At the same global level, Ram et al. [29] identify the need for a combination of fuels, including hydrogen, Fischer-Tropsch synthesis fuels and liquefied hydrogen and methane, in different proportions across different regions. Gray et al. [30] discuss that different types of fuels are needed depending on the transport sector. The authors find that hydrogen and ammonia may prevail in shipping in the long-run, but PtL jet fuels will be needed in aviation to deal with the large demand for this fuel. The haulage sector may also benefit from hydrogen as long as the fuelling infrastructure is strategically placed, but in the short-run compressed or liquefied biomethane are viable.

In the European context, Blanco et al. [28,29] found that hydrogen is suitable for heavy-duty road transportation due to the limitation on CO_2 sources and because their analyses indicate that CO_2 should be stored rather than utilised. However, the authors also acknowledge that aviation may use electrofuels in the future and that liquefied electromethane would be suitable for shipping. Lehtveer et al. [31] similarly argue that electrofuels are unlikely to become feasible due to high prices unless carbon storage is limited and CO_2 emission regulations tighten, while Brynolf et al. [32] agree that their competitiveness will depend on cost and environmental impact. On the other hand, Hannula and Reiner [33] make a critical assessment of what they call "carbon-neutral synthetic fuels" and battery electric vehicles, arguing that despite the low learning rate and questionable economies of scale of such fuels, they enable a gradual transition to sustainable transport without the externalised costs of electric vehicles. However, the authors acknowledge the problems carbon-neutral synthetic fuels face in terms of demand for resources, such as electricity and biomass.

The European Commission's view of a carbon-neutral EU, in their most ambitious 1.5 TECH scenario [34], indicates that biogas may be used for the power sector, combined with biomass and natural gas, while e-gas can be a suitable fuel for industry and heating purposes. Transport is served by 2nd generation liquid and gaseous biofuels, e-gas and hydrogen. In line with this, Helgeson and Peter [35] find that the heavy-duty road transport sector may rely on e-gasses, liquid hydrogen or Fischer-Tropsch diesel.

In their study, Mortensen et al. [36] include an analysis of the global potential of electrofuels, revealing that electrification and hydrogen integration will be required to limit biomass consumption. In another study, Mortensen et al. [37] highlight that future aviation can benefit from using biogas combined with carbon capture and electrolysis in gas-to-liquid (GTL) plants combined with Fischer-Tropsch synthesis. However, future demands will be challenging to meet if all the energy sectors do not achieve adequate electrification levels. This is in line with Connolly et al. [38,39], who analyse the potential for a 100% renewable energy system for Europe; they find that electrofuels are necessary to replace fossil fuels in heavy-duty vehicles and industry, complementing the high levels of direct and battery electrification. Unlike Mortensen [40], Connolly et al. [38,39] consider methanol and dimethyl ether (DME) preferred electrofuels. The potential of methanol and DME is studied in more depth by Ridjan et al. [41], who demonstrate that their production is more efficient than electromethane, including the infrastructure-associated costs. The authors also explain that hydrogen is not an economical solution due to the high storage and infrastructure costs, despite having lower production costs.

In the Danish national context, Albrecht and Nguyen [38] argue that biomass resources are insufficient to supply the potential fuel demands, concluding that Denmark's extensive wind resources can supply these demands using Fischer-Tropsch fuels from carbon capture. Other studies concerning Denmark [42,43] find Fischer-Tropsch liquids to be the most suitable, albeit produced as bio-electrofuels, due to the compatibility with the existing infrastructure and the lower price than the equivalent CO_2-electrofuels. Regarding infrastructure compatibility, the same authors [43] also claim that ammonia fuel for shipping requires radically different vessels due to the low density of the fuel. However, another study concerning Danish shipping [44] suggests using liquefied methane until the transition towards methanol, ammonia or hydrogen occurs.

Thus, the existing research presents several possibilities for future renewable fuel solutions, with many of the results depending on the methodologies used, regional or assessment tool limitations, and the authors' choice of technologies. The overarching results of the literature review show that although new fuels will be needed in the future energy systems in some form, a variety of solutions are argued suitable. This is expected, as no single solution can be the silver bullet, yet not all solutions can present the same benefits for the energy system and society, which can also translate into the hypothesis of this thesis. As such, this dissertation aims to identify those renewable fuels and their production and utilisation pathways by exploring the technical solutions that can enable an efficient and affordable design of any future energy systems. This also raises complexity issues, not only in the choice of fuels and pathways but also in the complexity of future energy systems.

2 RESEARCH OBJECTIVES

This dissertation's overall goal is to identify those renewable fuel pathways that enable the efficient and affordable design of future energy systems. Determining where and how each renewable fuel fits in the different parts of the energy system requires a holistic understanding of the energy system and the role of each accompanying technology. The production of renewable fuels is just one part of the increasingly complex future energy systems, but it is critical for the continued decrease of CO_2 emissions and for achieving future climate goals. Based on these goals, the following research question is defined:

Which are the feasible renewable fuel pathways that integrate with sustainable energy systems?

To align the research question to the scope of this dissertation, the terms used require a more detailed explanation:

- *Feasible:* This term refers to viable technical alternatives that consider economic, environmental, and social aspects to analyse complex energy systems solutions. Feasibility is explained and further integrated into the dissertation in the methodological section in Chapters 4.
- *Renewable fuels:* This term refers to fuels whose energy content is obtained exclusively from renewable energy sources. The carbon in these fuels is sourced from biomass conversion processes or emission capture from biogenic and non-biogenic sources, excluding fossil CO_2 emissions.
- *Pathways:* This term refers to the whole production and utilisation cycle of renewable fuels, from resources to end-use in transport or stationary units. Chapter 5 disaggregates the components that constitute each pathway.
- *Integrate:* This term is essential to this research question, as it indicates the inter-dependency between renewable fuel pathways and sustainable energy systems. It implies that changes in energy systems design will also influence the fuel production pathways and vice-versa.
- *Sustainable energy systems:* This appellation is preferred for describing future energy systems. The word "sustainable" is often interchangeable with "renewable", although they differ in meaning. "Sustainable" includes all renewable energy sources but may also include technologies that are not renewable, such as power plants on natural gas with carbon capture and storage (CCS) in so-called "carbon-neutral" energy systems. On the other hand, some renewable technologies, e.g. biofuels, may not be sustainable. This thesis's collection of studies includes both 100% renewable energy systems and carbon-neutral energy systems, so to broaden the perspectives of the solutions analysed in this thesis, the term "sustainable energy systems" is found appropriate.

The dissertation includes and is structured around a collection of three peer-reviewed research articles to answer the research question. The first study [1], titled "The role of biogas and biogas-derived fuels in a 100% renewable energy system in Denmark", deals with the choice of fuel conversion technologies for biogas across all energy system sectors namely electricity, heat, industry and transport. The second study [2], titled "The role of biomass gasification in low-carbon energy and transport systems", builds on the findings of the first study and expands the analysis towards dry biomass conversion using thermal gasification. The third study [3], titled "Techno-economic assessment of advanced fuels and propulsion systems in future fossil-free ships", takes a different approach to renewable fuels compared to the first two studies and analyses various fuels considered compatible with the shipping sector.

2.1 RESEARCH SCOPE AND DELIMITATION

The title of the thesis indicates an in-depth analysis of the potential of renewable fuel pathways in future energy systems. More specifically, the thesis refers to the feasible pathways as part of "sustainable energy systems". Although an explanation of the term is provided below the research question, it requires further clarifications on why it was chosen. First, the term sustainable is seen more comprehensive, as it includes renewable energy sources, but only those ones that can be sustainable. Secondly, although future energy systems should (and hopefully will) be dominated by renewable energy sources, in some cases, these systems will probably not be solely 100% renewable, but will also include CCS, which cannot be considered a renewable energy technology but may be a sustainable technology [45]. Although it is the author's opinion that 100% renewable energy systems are feasible [29,46,47], international organisms also call for CCS [7] to speed up the decarbonisation effort. Based on these considerations, and because the findings of this thesis are intended as guidelines for renewable fuel deployment in various future energy systems, the term "sustainable energy systems" is considered more suitable to deliver on the goals of this thesis.

The research question also emphasises the word "integrate", which should be understood as the reciprocal integration between renewable fuel pathways and sustainable energy systems. Since such integration can only occur at a system level, it calls for integrated energy system design approaches. In its turn, the design of energy systems refers to their architecture and operation. The architecture includes aspects relating to capacities, demands, primary energy supply, biomass consumption, energy grids or storages. The operation incorporates two other conditions, that of flexibility and temporal resolution. Flexibility is the capability of an energy system to efficiently integrate large amounts of VRES, while the hourly temporal resolution is necessary to determine the proposed solutions' technical and economic viability. The energy system architecture and its operation are essential aspects that contribute to answering the research question and are underlined in Chapters 3 and 4.

The thesis has a twofold scope to the analysis of feasible renewable fuel pathways. The three research articles incorporate both "top-down" and "bottom-up" approaches. The top-down approach is emphasised in Study 1 and 2 through the energy system perspective, aimed towards the national level (Denmark) and international level (the EU28). The scope of these two studies is to provide the system overview, and focus on primary energy supply, biomass consumption or energy system costs, results that can be separated into smaller segments or sectors in an aggregated perspective. While this is sufficient for energy sectors as power or heat production, it can lose detail in the transport or the industrial sectors. Although valuable insights are brought towards the industry sector, this analysis does not go into the same detail as it does with the transport sector. A part of the transport sector is dealt with in the bottom-up approach in Study 3, which complements the top-down approach and acts as a method for compensating the aggregated perspective on the transport sector in the first two studies. Study 3 zooms in on fuel costs, propulsion systems, utilisation rates, and the total cost of ownership to identify if the energy system level results can also be confirmed on a fuel-propulsion system level. Study 3 is focused on the shipping sector, but it proves as a valid point of departure for understanding the implications of renewable fuel choices in other transport sectors.

The dissertation's overall focus remains on the feasibility of cost- and energy-efficient renewable fuels pathways from an energy system perspective, with the three studies allowing to cover the entire cycle, from resources to utilisation. In this respect, the thesis does not cover aspects that relate to their implementation, nor does it define a roadmap for deploying these fuels, although the results of this thesis can be a stepping stone in the definition of such roadmaps or interpreted as policy inputs.

Other valuable perspectives on the potential of renewable fuels and the related pathways can result from market analysis. Although not explicitly investigated in this thesis, which targeted the technical operation of systems (Study 1 and 2), insights from a market perspective are included in Chapter 8.

2.2 STRUCTURE OF THE THESIS

The dissertation is split into nine chapters. Chapter 1 introduces the reader to the concept of renewable fuels and the findings of various authors on this topic. The chapter reveals the necessity for renewable fuels to replace fossil fuels and move on towards sustainable energy systems, but also the lack of consensus on which type of fuels and production pathways should be used in the future; this leads to the research question and related objectives in Chapter 2.

Chapter 3 provides the "map" on how the choice of renewable fuels pathways should occur, introducing four guiding theoretical approaches. Chapter 4 provides the methods for navigating this map and achieving the goals set in the research question and sets the basis for the feasibility study.

Chapter 5 delves into the challenges and solutions for renewable fuel production and utilisation by emphasising the system-level aspects. The chapter disaggregates the production pathways into five core components: resources, primary conversion, secondary conversion, storage and infrastructure, and utilisation.

Chapter 6 is the collection of studies in this dissertation, included as full-length journal articles, while Chapter 7 synthesises their main findings. The Supplementary material from Study 3 is included at the end of the document.

Not least, the dissertation continues in Chapter 8 with a discussion on the results of the three studies in the greater context, beyond the results in the three articles. This is followed in Chapter 9 by the conclusions and Chapter 10 with the suggestion for further work.

3 MAPPING THE CHOICE OF RENEWABLE FUEL PATHWAYS

The theoretical framework guiding this dissertation should be understood as a map where representations of the world are required to raise awareness of the available alternatives and the ways to solve problems. Without such a map, or with an incorrect map, the route toward achieving goals may be longer, more expensive or filled with pitfalls. Choosing the correct map may not be an easy task, but it is crucial for solving the given problem. But as each problem is unique, the framework for solving it must be tailor-made.

The problem identified in this thesis relates to the variety of renewable fuels and pathways argued suitable for replacing fossil fuels and contribute to the decarbonisation efforts. However, the hypothesis is that not all renewable fuel pathways are equally beneficial to the energy system and society. The societal aspect is essential here, as the elimination of fossil fuels and decarbonisation of energy systems can only occur at a large-scale with implications beyond energy systems, which is why the societal aspects link closely to sustainability, further explained in this chapter. Based on these observations, the thesis sets the goal to identify the feasible renewable fuel pathways that integrate with sustainable energy systems, aiming that the results of this thesis can also be generalised as guidelines for the future deployment of such fuels.

This chapter proposes a framework of four theoretical principles to solve the problem and identify feasible solutions. Each theoretical principle has a separate key role in reaching the goal, but all the principles interconnect and build on each other. Figure 1 illustrates these theoretical principles, while the rest of this chapter goes in-depth with developing the theoretical framework.

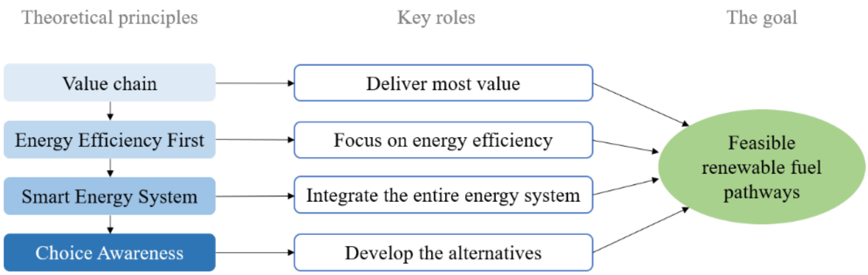

Figure 1: The four theoretical principles and their key role in identifying the feasible renewable fuel pathways in sustainable energy systems.

3.1 VALUE CHAIN

"Value chain" is an entrepreneurial term referring to the activities undertaken by a company that, together, convert raw materials into final products. It provides a systematic way of examining and disaggregating the activities in a firm and how they interact to analyse sources of competitive advantage. The final product of a "value chain" may be a physical product or a service; the overall goal of the value chain is increasing a business's efficiency to deliver the most value at the lowest possible cost [48].

In business economics, value refers to the total amount the buyers are willing to pay, including the production costs plus the margin. The margin depends on managing the linkages between the activities and the reductions in production costs. The other part of the value chain consists of value activities, which are the physical and technological activities of a company. The way each activity is combined determines whether or not the product or service is competitive [48].

This concept may be applied to the context of designing renewable fuel solutions. The product is the fuel, and the goal can be adapted: deliver the most value for the energy system at the least possible cost. The production of renewable fuels fits within this concept, as producing low-cost fuels is continuously sought, which may be the outcome of the efficiency of a specific process.

The value activities in a value chain can also be adapted to those of renewable fuel pathways, where the "activities" can be considered the components of the pathways. Figure 2 illustrates the components dedicated to renewable fuel pathways:

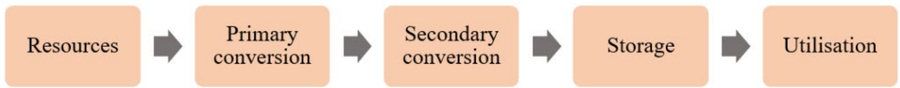

Figure 2: Value activities or the components in a renewable fuel pathway.

The disposition of the pathways as value chain activities also enables the disaggregation of the pathways into the key resources and technologies involved. It provides the basis for the in-depth description of these components in Chapter 5. The resources and technologies involved are:

- Resources: VRES, biomass, CO_2, N_2, water;
- Primary conversion: electrolysis, biomass conversion, carbon capture;
- Secondary conversion: fuel synthesis, fuel upgrading;
- Storage: on-land and on-board vehicles, fuelling infrastructure;
- Utilisation: turbines, engines, fuel cells.

The value chain in the pathways for renewable fuels is similar to that of any other manufactured product, but whether it is a suitable solution from a societal perspective depends on the combination of "activities". It is also essential to highlight that a low-cost fuel may not necessarily be the most energy-efficient solution, so this concept alone may be insufficient in the greater context of the sustainable energy system. Therefore, it is accompanied by another theoretical concept, described in the next section: The Energy Efficiency First principle.

3.2 THE ENERGY EFFICIENCY FIRST PRINCIPLE

The Energy Efficiency First principle is a concept established by the European Commission as a strategic priority that rethinks energy efficiency, treating it as its own kind of energy source. Energy efficiency is commonly defined as the amount of energy output for a given energy input [49], but the EU uses a broader definition, where Energy Efficiency First:

> "means taking utmost account in energy planning, and in policy and investment decision, of alternative cost-efficient energy efficiency measures to make energy demand and energy supply more efficient, in particular by means of cost-effective end-use energy savings, demand response initiatives and more efficient conversion, transmission and distribution of energy" [50] (Page 15)

The definition reveals the existence of three types of energy efficiency. Energy savings refer to reducing demands, such as building insulation that uses less heat or the replacement of cars with bikes. Demand response refers to shifting demand from one time to another to shave peaks, which could apply to home appliances or industrial demands. Finally, the focus in this thesis is on the efficient conversion, transmission and distribution of energy. A new CHP plant can be an example of improved conversion performance, while high-temperature electrolysis can entail a more efficient use of electricity than low-temperature electrolysis. This principle can apply consistently in the energy system, where efficiency may refer to the flexible operation of electrolysers using variable renewable electricity sources rather than electricity from power plants. Therefore, the Energy Efficiency First principle can be understood in terms of improved ways to utilise energy that maximise the benefits, including the cost of the outputs [49].

There are further benefits of energy efficiency beyond reduced energy consumption, such as lower expenditure with certain fuels and lower investment cost in renewable energy infrastructure (fewer wind turbines and less expensive transmission lines), without which achieving renewable energy systems would be more expensive and more complex [49]. Converting all current transport demands to renewable liquid or gaseous fuels is a classic example: significantly more resources would be needed to cover the demands, raising issues regarding the available land area to sustain such a transition [51], which is why electric vehicles are a central part of the design of sustainable energy systems.

Moreover, energy efficiency can help reduce GHG emissions, lower environmental impacts from fuel extraction, improve air quality and have indirect health benefits. Other quantifiable benefits include increased energy security through the lower demands for imported fuels and the creation of new jobs in the industry [49].

While the transition to renewable energy systems is not the focus of this dissertation, the Energy Efficiency First principle is a guiding concept throughout the dissertation's analyses. Together with the concept of the value chain, it narrows down and solidifies renewable fuel production principles. However, the two concepts do not touch sufficiently on other essential aspects, such as integrated energy solutions and biomass availability, which is why the next concept is introduced: Smart Energy Systems.

3.3 SMART ENERGY SYSTEMS

In a broader sense, the concept of Smart Energy Systems encompasses the Value chain concept and Energy Efficiency First principle by adding energy system aspects not found in the other two concepts. These added components concern the architecture and the operation of future energy systems [52], aspects already mentioned as critical in identifying the feasible renewable fuel pathways. The goal in a Smart Energy System is similar to those of value chains and the Energy Efficiency First principle: to deliver the most efficient solutions at the lowest possible cost. However, it adds more considerations for accomplishing this goal: integrated energy systems and the sustainable use of biomass.

Existing energy systems use different energy grids to meet the electricity, heating, industry, and transport sector demands. Traditionally, infrastructure systems like the electricity, district heating and natural gas grids operate separately, each supplying a specific set of demands without interfering with each other. In the future, this will have to change as future energy systems with high degrees of VRES will require integrated infrastructure rather than segregated and over-dimensioned energy grids that do not correlate with each other to deal with the intermittent supply. For this reason, future energy grids require coordination with other infrastructures to identify synergies, increase efficiency and reduce costs compared to solutions that solely focus on one grid [52]. By definition, PtX fuels entail integration between electricity and gas or liquid fuel infrastructures, linking large-scale renewable electricity sources to vast liquid and gas storage capacities. Another example is PtH, which can achieve another efficiency improvement, such as linking electricity to the heating sector. Figure 3 illustrates a simplified perspective on some of the potential links in a Smart Energy System.

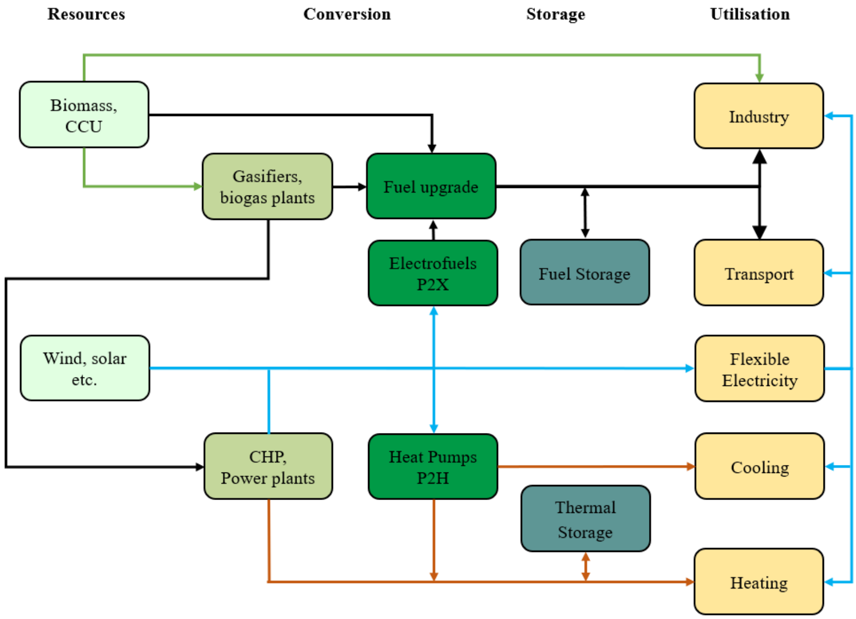

Figure 3: Simplified perspective of a Smart Energy System illustrating the main technologies and grids: electricity (blue), heating (red), gas and liquid (black) and potential biomass consumers (green).

The other key aspect of energy systems introduced by this concept is that of sustainable biomass consumption. A broad definition of sustainable development is the one offered by the Brundtland report [53], as "meeting the needs of the present without compromising the ability of future generations to meet their own needs". Sustainable biomass consumption has implications far beyond energy systems, with significant social and environmental impacts. Through its integrated approach to energy infrastructures, the concept of Smart Energy Systems can reduce biomass consumption, e.g. by using electricity instead of biomass for fuel production (in the case of PtX) or waste heat instead of biomass in the heating sector.

In other words, the Smart Energy Systems concept couples with the concepts defined in the previous subchapters to make clear that future renewable fuel production must include critical aspects such as affordability, energy efficiency, integrated operation and sustainable biomass resources. However, to complete the perspective explained in this chapter and to amalgamate all principles illustrated in Figure 1, the theoretical framework is completed with the theory of Choice awareness.

3.4 CHOICE AWARENESS THEORY

The Smart Energy System concept is a paradigm for designing future renewable energy systems beyond the technology level to an integrated system perspective. As mentioned previously, such energy system transformations entail changes at a societal level, and the Choice Awareness theory addresses collective decision making.

The word "choice" is essential in this theory (as it is throughout the thesis), and it is commonly defined as the possibility of choosing or preferential determination between two or more options. To make a choice, one must be able to judge the advantages and disadvantages and select one or more options. The theory further differentiates between true and false choices, claiming that "true" choices are between real options, while "false" choices refer to situations where there is an appearance of choice, but the act of choosing does not actually occur [52].

The word "awareness" is the quality, the state of being aware or conscious. It does not imply the understanding of the act but just the ability to perceive a condition. Combining "choice" with "awareness" involves the element of understanding and judging the options, which is typically followed by the act of selecting between "true choices" [52].

Choice Awareness must occur at a societal level where the theory proposes a strategy for raising awareness on multiple levels that real alternatives exist. The first step is designing concrete technical alternatives that facilitate the direct and equal comparison of alternatives in terms of critical parameters, such as capacity and energy production. The assessments should also include aspects such as renewable energy consumption, efficiency improvements or savings in demand. The next step is to evaluate the social, environmental and economic aspects of the proposed alternatives that may influence the implementation. Not least, the analysis of such alternatives should be performed with a long-time horizon to find the best solutions that are independent of the existing technologies in the current energy system. By creating viable alternatives, the collective perception in society can change, which can play an essential role in designing future energy systems [52].

Choice Awareness theory complements the other concepts presented in this chapter by providing a method for analysing complex energy systems. In absolute terms, it also describes the role of this thesis and associated studies, that of raising awareness of real choices. Furthermore, as described in the next chapter, the theory provides the background behind the choice of tools for designing technical alternatives.

4 METHODOLOGICAL FRAMEWORK

Now that the theoretical principles guiding the choice of renewable fuel pathways are mapped in the preceding chapter, this chapter describes the methods that aid in answering the research question. The methods draw on the guidelines for raising awareness described in the Choice Awareness theory: design technical alternatives, evaluate economic, environmental, and social aspects, and place them on a long-time horizon.

The research question inquires on the feasible renewable fuel pathways that form part of sustainable energy systems. Thus, conducting a feasibility study is a natural step in answering the question. A three-step approach is used to answer the research question, inspired by the method developed by Hvelplund and Lund [54]. The first step aims to frame the research and uses a "www-analysis" to answer the W*hat, Why, Who* questions related to renewable fuels pathways. This section is described in Chapter 4.1. The second step answers the *How* question and essentially describes the methods and tools used to develop the results, which are then summarised in Chapter 4.2 and 4.3, while the third step is the actual feasibility study conducted in the three research articles.

4.1 THE FEASIBILITY STUDY

There is no specific methodology for designing feasibility studies. These are various types of assessments designed to determine the best solutions among alternatives. All assessments of this sort should account for technical alternatives while including economic, environmental and social factors that will influence the results. Such broad analyses can also be seen as part of complexity thinking and can help study the interactions between energy systems elements [55]. Much like all assessments that study systemic changes, feasibility studies must also be placed in time and space, and sensitivity analyses must be included to reduce the uncertainties of the results.

But before conducting the analysis, a part of the feasibility studies is to frame the research, where one should answer the type of questions proposed by the www-analysis, as to *What should be studied? Why is this important?* and not least *Who is the beneficiary of the study?* The following paragraphs take each question in part.

- What should be studied?

Renewable fuel production pathways are the topic of interest in this thesis. Such production pathways generally involve several components with various roles and characteristics (further described in Chapter 5). While it is possible and practical to perform a feasibility study on a plant level, it will always be limited to revealing the potential of the plant itself. While this may be useful in some situations, it is vital to have a broader perspective that includes the interactions between multiple plants and components across the entire energy system, as performed in Study 1 and 2. Renewable fuel production pathways that include electrolysis consume large amounts of electricity but also offer a balancing effect on the electricity grid, so their impact goes well beyond the electrofuels they produce. Some of the pathways also use large amounts of water and biomass or require carbon capture in place that will impact the available resources and environment in a given geographical location. The production of renewable gaseous fuels may also require an infrastructure to store and transport the produced gases that will impact the existing gas grid, especially in changing energy demands in future energy systems. Not least, such renewable fuel plants also produce large amounts of waste heat that require a district heating infrastructure to make use of the heat.

These are some of the reasons why analyses on renewable fuels must consider the whole energy system and beyond, not only the plant or sector where they are implemented. Such analyses must be placed on time-horizons that make justice for all technologies since all energy infrastructure investments have long lifetimes. The time-horizons will be dependent on the research goal, but these need to be far enough in the future also to include emerging technologies or technologies that now may be in the demonstration phase. Performing feasibility studies in the present will likely still favour existing technologies since they are based on a so-called "economic optimum" favouring fossil fuels.

- Why is it important?

Renewable fuels are one of the solutions for reducing GHG emissions, replacing fossil fuels in the energy system, and increasing the security of supply. However, renewable fuels are not a measure that fits all scopes and sizes, so it is essential to clarify where they position themselves in the energy system. To understand their role, one must look back at the theoretical framework, namely the Energy Efficiency First principle and the Smart Energy System concept. Renewable fuels are complements to other more efficient energy systems measures, as VRES in the power production sector, electrification in transport and industry and district heating and heat pumps for the heating and cooling sector. Despite these being "lower hanging fruits", renewable fuels remain necessary in all types of renewable energy systems, and it is the aim of this thesis to determine the appropriate use of renewable fuels and the pathways to produce them. As described in part three of the feasibility study, not all renewable fuels are equally suitable in all applications as not all pathways create value in the energy system.

The *Why is it important?* question also relates to the interest in reducing CO_2 emissions. National and international goals must be reflected when designing feasibility studies, building on the environmental aspect of feasibility studies. The studies included in this thesis relate to 2050 emissions goals. Study 1 is linked to the Danish goals of a fossil-free energy system by 2050 [56]. Similarly, Study 2 covers the Danish goal for 2050 and the EU goal of carbon neutrality by the same year [11]. Study 3 relates to the International Maritime Association (IMO) goal to reduce shipping emissions by 50% until 2050 [57].

- Who is the beneficiary of the study?

Within feasibility studies, an important distinction is made between socio-economic and business-economic studies, each intended for different audiences. The former analyses whether a project is for the benefit of the society, while the latter analyses the feasibility of a project from a business perspective, i.e. considering existing market incentives and constraints. The topic discussed in this dissertation, that of large-scale renewable fuel production, requires new technologies to compete with well-established oil and gas products. Because the existing market conditions are far from perfect, comparisons of technologies under current conditions will favour old technologies ingrained in current political and institutional frameworks. This is why such studies should not be performed in current institutional contexts, using taxes, levies or without accounting for their full environmental impacts. Otherwise, it will be difficult to see the benefits of new technologies. From this perspective, this thesis can be considered a socio-economic feasibility study. The intended beneficiaries are the members of the society, the Danish government, the European Commission, fellow researchers and energy companies interested in determining which technologies and solutions to invest in the future.

Feasibility studies are complex assessments. This thesis and the accompanying studies strive to provide holistic results that take account of all the elements of such a study. Rightfully so, the analyses build on technical alternatives with long-term (2050 in Study 1 and 2) and medium-to-long-term horizons (2030 in Study 3), delving in economic aspects and including environmental and social considerations. Other studies may focus more on the environmental component, such as life-cycle assessments, or the social component, such as behavioural studies or studies that inquire about the social acceptance of technologies. While all these studies may create feasibility studies with different focuses, they can all contribute to the same goal. The type of assessment in this thesis has a greater emphasis on technical and economic aspects, primarily highlighted by the tools used for the assessments: energy system analysis and techno-economic assessments.

4.2 ENERGY SYSTEM ANALYSIS

Energy systems are complex structures designed to operate seamlessly based on many technologies, regulations, inputs and outputs that influence each other. As energy systems transition to renewable energy, they become even more complex, dealing with new energy carriers, variable renewable energy sources, resource limitations and changing demands. Responding to these changes requires designing concrete technical alternatives that consider all aspects of future energy systems. Such a tool must be able to identify and quantify the alternatives:

- *Include the entire energy system*, as per the Smart Energy System concept, which is critical for comparing the large-scale integration of renewable fuels in the electricity, heat, transport and industrial sectors.
- *Support hourly resolution* to analyse the influence of fluctuating VRES and seasonal differences in production and demand.
- *Include radical technological changes*, vital in achieving all types of highly renewable and sustainable energy systems.
- *Include national and international level resolution*, which can optimise the resource use technical operation of the entire energy system.

An energy system analysis tool that can meet these modelling requirements is EnergyPLAN, which was also the tool of choice in Study 1 and 2, illustrated in Figure 4. This tool is designed to model the hourly operation of all energy sectors over one year, including the electricity, heating, transport and industry sectors. Based on technical and economic analyses and the consequences of implementing different technologies with different investment and operational costs, the tool can help design and plan different regional and national strategies [52,58].

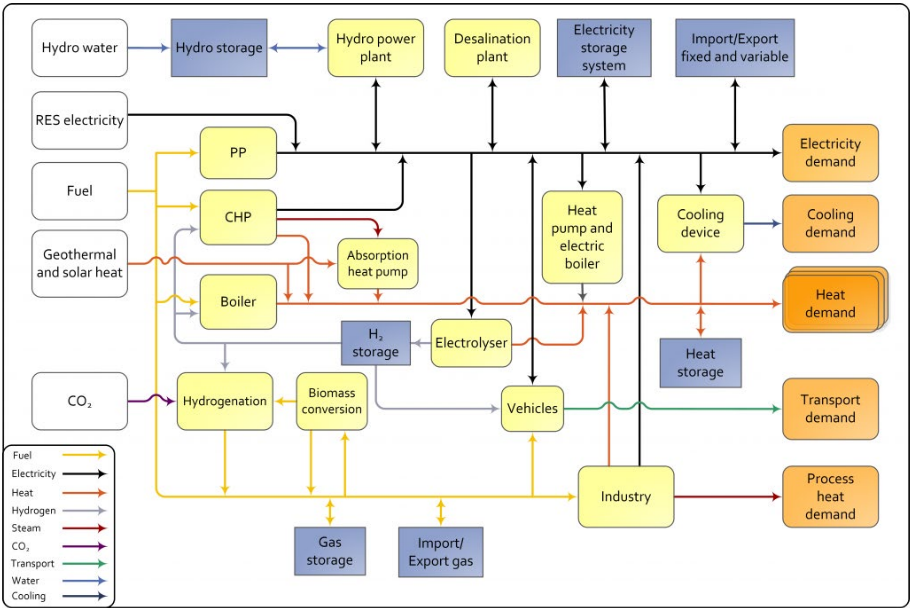

Figure 4: The integrated energy system in the EnergyPLAN modelling tool.

EnergyPLAN is a deterministic model, meaning that it will always provide the same output given the same input. This is relevant when comparing technical alternatives where parameters are compared equally in terms of capacity and production, as explained by Choice Awareness theory [52]. The EnergyPLAN model is also built as a simulation tool, meaning that it analytically simulates the energy system based on established priorities and system responses [59]. The idea behind this approach is to allow the modeller to compare scenarios that differ in critical parameters, such as investment costs, efficiencies or energy supply. Therefore, in a simulation approach, the modellers compare alternative routes with different strengths and weaknesses rather than leaving the model to choose for them, which is the essential difference to the optimisation approach, where the model decides the optimal solution – if an optimal solution indeed exists.

An optimisation model may be constrained by CO_2 emissions or energy consumption but is most often constrained by cost. To identify the least-cost optimal solution, the description of the starting point – usually, the current energy system – is essential. The process is called forecasting and is opposed to the term backcasting, specific to simulation models such as EnergyPLAN. In EnergyPLAN, the focus is on describing the desired energy system with its many options (scenarios), with less effort on describing the existing energy system. Backcasting then allows the modellers to find transition pathways from the desired energy system [59]. However, the transition to renewable energy systems is not the focus of this dissertation, which instead describes how renewable fuels can be integrated with future energy systems.

Despite its categorisation as a simulation model, EnergyPLAN does have some level of optimisation. Specifically, it optimises the technical operation of the energy system, which becomes an important aspect given that prices are an outcome of institutionalised markets and political decisions (which influence the definition of optimality), including investment costs or fuel prices [52,59]. Such uncertainties underline the importance that the sought solutions need to be based on flexible assumptions, i.e. robust scenarios that account for technological uncertainties and diverse prices.

The EnergyPLAN modelling tool reflects in its design the theoretical concepts presented in Chapter 3. The Smart Energy System concept is emphasised in the tool by modelling the complete energy system and calculating the hourly electricity balance and the district heating, cooling, hydrogen and natural gas systems, including biogas, gasification or PtM. The Value chain and Energy Efficiency First principles are embedded in the concept of Smart Energy Systems. In addition, guided by Choice Awareness theory, the tool enables the user to create a large number of scenarios thanks to analytical programming and short computational times while also benefiting from the capacity to analyse radical technological changes [52,58,59].

4.3 TECHNO-ECONOMIC ASSESSMENT

A techno-economic assessment (TEA) is generally used to estimate the technical and economic performance of a product before it is built. It is another method for analysing technical alternatives that also include economic, environmental and social aspects. TEA was applied in Study 3 to identify the economic performance of a combination of technologies suitable for the shipping sector under certain technical constraints.

In absolute terms, TEA can be framed by Choice Awareness theory. The method provides a variety of alternatives, with various strengths and weaknesses to be identified and discussed. The alternatives can be compared based on central parameters such as annualised costs and efficiencies while also considering renewable energy, environmental and social aspects.

As the TEA deals with cost data and technical parameters for future technical solutions, it is very dependent on current estimations and expected learning curves. Costs and efficiencies are a general issue that even the energy system analysis approaches need to tackle, and it is one of the reasons why technical assessments may often provide more certainty than economic assessments.

The analysis in Study 3 is brought forward in time than the energy system analysis, i.e. to 2030, to deal with the cost uncertainty. The TEA in Study 3 analyses a small part of the energy system, the maritime transport, so long-term horizons may not be as important as for more complex structures, such as entire energy systems. However, it is relevant to understand if the results of energy system analysis and techno-economic assessments converge on similar results despite the more conservative datasets used for the TEA in 2030. This is also why this method includes a range of sensitivity analyses on central parameters, which should indicate the robustness of the results. TEA should thus be seen as a complement to energy system analysis as it incorporates a more detailed analysis on the utilisation level for the technical alternatives.

5 COMPONENTS FOR RENEWABLE FUEL PATHWAYS

The theoretical framework proposed in Chapter 3 includes the concept of Value chain to describe value activities in the form of components for renewable fuel pathways. This chapter takes the disaggregation of the pathways further to describe the characteristics of technologies and resources involved in fuel conversion, storage and utilisation primarily from an energy system perspective, as illustrated in Figure 5. This chapter aims to introduce the reader to the technical alternatives and should not be interpreted as a technology catalogue. Where deemed necessary, this chapter includes cost data as a method for comparing technologies, while each of the three research articles provides detailed efficiency and cost data for the technologies analysed.

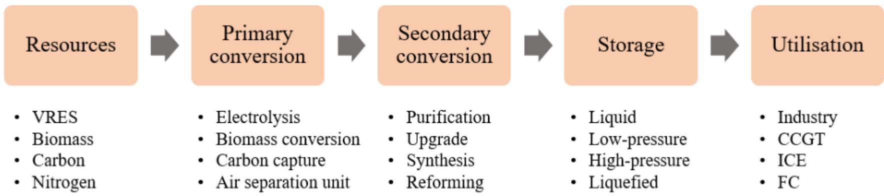

Figure 5: The key components of renewable fuel production pathways.

5.1 RESOURCES

The availability of resources and the potential for harnessing them form an essential aspect of future fuel production. The overall aim of reducing and replacing fossil fuels in the energy system with renewable and carbon-neutral energy relies on the replaced fuels originating from renewable sources such as wind, solar photovoltaics, biomass, and carbon and nitrogen resources. Hydropower is another important resource; however, it is not included in this dissertation due to its geographical limitations but remains an important energy source. In this chapter, VRES, biomass, carbon and nitrogen resources are further discussed.

One key non-energy resource is water, an essential and, in some cases, a limited resource for electrofuel production, which is often excluded in energy system analyses. Water is an indispensable resource for electrolysers, but it has other uses throughout the fuel production value chain, either with carbon capture [60,61] or fuel synthesis [62,63]. For electrolysers, water consumption is significant, at around 9-11.4 kg/kg$_{H2}$, and is dependent on the type of electrolyser [64–66]. In this dissertation, water is assumed to be available in the three studies, although it is not included in the analyses.

The area necessary for the deployment of renewable energy is another type of non-energy resource. All renewable energy sources require space for deployment, although some require more than others. Biomass is the most land-intensive, requiring approximately 500 km^2 to produce 1 TWh of energy, while wind and photovoltaics require less than one tenth of this area to produce the same amount of energy [67]. Although these numbers refer to electricity production and not renewable fuel production, these are essential considerations for designing renewable fuel pathways.

5.1.1 VARIABLE RENEWABLE ELECTRICITY SOURCES

VRES are a critical component of all renewable fuels and sustainable energy systems. The most utilised types of VRES are onshore and offshore wind, solar photovoltaics and solar thermal. While solar thermal is specific to heating systems, the other three VRES can be used in connection with the production of all types of electrofuels.

VRES are impacted by air mass movements and solar radiation, which is reflected in their full load hours. Full load hours are an essential metric in all energy applications as well as electrofuel production as they dictate, to a large extent, the operation of the electrolysers. The Danish Energy Agency [68] estimates that average full load hours will continue to improve and, by 2050, these may reach 1500 hours for photovoltaics, 3800 hours for onshore wind and 4900 hours for offshore wind (values specific for the Nordic area). Offshore wind's advantage in full load hours means that its capacity utilisation is higher, which is reflected in the full load hours of electrolysers. Hence, offshore wind is often linked to the large-scale deployment of electrofuels and Study 1, 2 and 3 are designed with this consideration.

Offshore wind can also be deployed at larger scales than onshore wind in terms of the turbine and aggregated wind farm capacities, as land restrictions are not an issue for offshore infrastructure (although there may be other restrictions). Offshore wind can also address the problem of "NIMBY" ("not in my back yard") attitudes, as the visual and noise impacts occur far from most of the population [68,69]. Even though this incurs higher costs than other VRES, the average offshore wind LCOE in Europe has decreased by 44% in the past ten years, reaching 45-79 €/MWh in 2019 [16] with further reductions in sight [70]. Based on the Danish Energy Agency estimates, these may reach approximately 30 €/MWh in the medium to long term [68].

5.1.2 BIOMASS

Biomass is a broad term that includes a variety of feedstocks originating from forestry, agriculture, some types of waste, and crops grown for the purpose of producing energy. It is a highly valued component for future energy systems due to its carbon neutrality: theoretically, the carbon released in the combustion or conversion of biomass to other fuels has already been captured through photosynthesis from the atmosphere, meaning no new fossil-origin carbon is released. In practice, this is only partly true as there is a limit to how much biomass may be deemed sustainable, and the emissions of uncontrolled large quantities of biomass could contribute to the accumulation of CO_2 in the atmosphere [71,72].

Due to its very nature, biomass is a limited product with an uneven distribution. Global non-food biomass potential is between 13 and 28 GJ per capita per year [73], while in Europe, it is 15-16.5 GJ per capita per year, depending on the source [74,75]. Current biomass consumption in the EU is just below 6 PJ/year [76], but estimates for the future vary between 8 and 20 EJ [75], depending on the level of exploitation, with the EU's long-term strategy [34] estimating up to 13 EJ/year by 2050 in the most ambitions scenario. Denmark is estimated to have between 25-35 GJ per capita yearly, depending on which biomass types are included in the estimates. According to various publications [76–78], the Danish potential can reach around 160 PJ/year without including energy crops or algae. With improved straw collection and including energy crops, and incorporating current plans for afforestation [79], these resources could reach over 200 PJ/year [77] based on the more conservative estimates. The estimates for Denmark and Europe are illustrated in Figure 6.

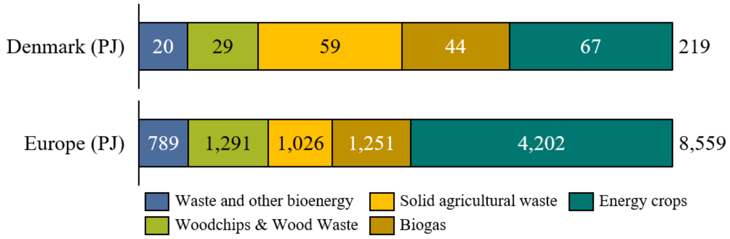

Figure 6: Conservative biomass potential estimates for Denmark and Europe.

Despite its limited potential for energy purposes, biomass is the only renewable resource that can offer the energy system flexibility, similar to that offered by fossil fuels today. Flexibility means that fuel can be stored and then used when needed. For the production of renewable fuels, biomass can be an essential asset as it already contains hydrogen and carbon atoms – the "ingredients" for all hydrocarbons. Apart from the potential to produce biofuels, this is an essential aspect for the production of bio-electrofuels, as this entails reduced electrolytic hydrogen consumption.

5.1.3 CARBON AND NITROGEN

Carbon and nitrogen are abundant in nature. Carbon is found in excess in the atmosphere in the form of CO_2 and is the most significant contributor to global temperature increase and climate change. However, CO_2 and N_2 can also combine with hydrogen to produce a variety of fuels.

Despite its increasing concentration in the atmosphere, CO_2 is relatively sparse compared to the most abundant component, N_2. However, CO_2 can be found in concentrated streams in all combustion processes or other chemical processes. It is not feasible to capture CO_2 from all emitters, but it is possible to capture it from large CO_2 emitters that do not utilise fossil fuels, a requirement for producing renewable fuels.

Electrofuel production involving hydrocarbons will require reliable sources of carbon with sufficient quantity and flow, which will entail the constant operation of sufficient carbon emitters or ensuring the temporary storage of CO_2 until the time of use. Current large CO_2 emitters are power plants or combined power and heat plants. However, as more VRES take over electricity production and PtH solutions replace fuels in heating, the amount of CO_2 emitted will decrease, which also offsets the production timing, making such thermal power and heat production uncertain for large-scale CO_2 capture [80]. This may leave the industry as the primary CO_2 source for fuel production, but with electrification and changing fuels [81], the options will become fewer. The unavoidable emissions from cement factories may remain a reliable source of CO_2, both in quantity and flow, but this will require synergies with on-site fuel production to avoid costly transport and storage.

5.2 PRIMARY CONVERSION

Primary conversion entails transforming resources into core components for either further fuel conversion or final use. This refers to electricity and water to hydrogen, biomass to biogas/syngas/bio-oils, and CO_2 and N_2 to syngas. This chapter describes electrolysis, biomass conversion and CO_2/N_2 capture technologies.

5.2.1 ELECTROLYSIS

Electrolysis is the central technology for all electrofuel production and an enabler of the large-scale deployment of renewable fuels. There are three main types of electrolysis technologies: alkaline (AEL), polymer membrane (PEMEL) and solid oxide electrolysis (SOEL). AEL is currently the most mature technology and can be deployed on the hundred MW scale, although PEMEL is rapidly scaling up and offers more flexible operation [82,83]. SOEL is the least developed of the three technologies, but it is also the most promising since it can deliver high efficiencies and low costs [83]. Based on these considerations, SOEL would be the preferred technology in all cases, but future energy systems may, in reality, have a mix of all three. Due to their technology readiness levels, AEL and PEMEL may see large-scale deployment by 2030 in an accelerated energy transition, while SOEL may be deployed later if the technology becomes ready. There will also be various providers competing with each other, and some technologies may fit better with some fuel processes than others, depending on aspects such as hydrogen purity or potential heat integration with other fuel production processes.

From a systems perspective, electrolysis offers further opportunities, such as the integration of the oxygen by-product with thermal gasification or oxyfuel combustion and carbon capture (further described in Section 5.2.3), or the potential to obtain additional revenues by selling oxygen. This will depend on the demand for this product, with some authors suggesting oxygen revenues of 23-87 €/t O_2 [84–86]. Waste heat from electrolysis offers similar possibilities and could be a valued product if a market and the infrastructure to use it exist. Sorknæs et al. [87] evaluated the potential price of heat produced for district heating in the context of a future competitive heating market and found this can only vary at around 10 €/MWh, which is much lower than the price of future fuel production. However, other authors use current market prices for waste heat at 30-40 €/MWh [66,88].

Besides converting electricity to hydrogen, electrolysis may also be a means of stabilising the grid for large renewable electricity capacities in times of high wind or solar production. Provided that enough capacity exists, this may provide additional income for electrofuel plants, potentially lowering fuel costs. PEMEL is currently the most flexible in this sense, with a wide load range and short start-up times, while AEL is more limited at 20-50% load changes and longer start-up times [82]. However, both should offer fast responses to grid signals at operating temperature, although more optimisation may be needed in this sense in the future. On the other hand, SOEL is still unproven at a large scale and still deals with a short stack lifetime, pressurised operation or load cycling.

The total installed electrolysis capacity will also affect energy system operation, fuel consumption and total cost structure. Such systems with large-scale fuel production aim to correlate the operational hours of electrolysis with offshore wind production. This essentially means increasing the electrolysis capacity to minimise fuel consumption in power plants. In turn, this results in lower expenditures on fuels but higher investment in electrolysis. Such a design also requires sufficient temporary hydrogen storage to handle the low operational hours of electrolysers and supply enough hydrogen for fuel production, which does not have the same potential for flexibility. Steel tanks or underground cavern storage may be used for this purpose, albeit with significantly different costs. Therefore, the hydrogen storage size must be coordinated with the electrolysis capacity, the subsequent fuel synthesis and, last but not least, the syngas or CO_2 source. In an analysis for a 100% renewable energy system for Denmark in 2050, Sorknæs et al. [4] found that the size of hydrogen storage is very dependent on its type and cost, estimating it as being equivalent to 2.5 to 4 days' worth of daily hydrogen production together with about 6000 full load hours for electrolysis. This is also similar to the findings of the Danish Transmission System Operator, Energinet, in their report [89], which also narrows down the lowest electricity prices at 6000 hours per year.

Consequently, the technical operation optimisation of these technologies is at the core of the Energy Efficiency First principle and the Smart Energy System concept.

Previous work included such a design for flexible fuel production to model 100% renewable energy systems [38,39,90], and Studies 1 and 2 apply a similar method. Study 1 considers SOEL exclusively, as in the original model [75], while Studies 2 and 3 assume a mix of electrolysers that should reflect the potential future technology mix more accurately. Each article provides separately more detail on all these aspects, including the investment cost and efficiencies associated with electrolysis.

5.2.2 BIOMASS CONVERSION TECHNOLOGIES

Multiple conversion technologies can process a variety of biomass inputs. This section introduces these technologies and links them with compatible types of biomass. The chapter divides the technologies according to the state of the output product:

- Gaseous: anaerobic digestion, thermal gasification
- Liquid: hydrothermal liquefaction (HTL), pyrolysis, fermentation, hydroprocessing, and transesterification.

The gaseous products in the first category are biogas from anaerobic digestion and syngas from thermal gasification. Biogas is a mix of CH_4 and CO_2 plus impurities. When used in stationary applications, biogas does not require CO_2 removal or the cleaning of impurities, although the impurities will need to be removed in the case of further fuel synthesis.

Syngas is a mix of various components, including CO, CO_2, N_2, H_2, H_2O and other impurities. Like biogas, syngas can be combusted directly in stationary applications, but fuel synthesis requires cleaning and balancing the H_2 and CO in specific stoichiometric ratios, depending on the subsequent fuel synthesis.

The liquid products in the second category are bio-oils, bio-ethanol and bio-diesel. Bio-ethanol is the product of fermentation and can be used directly in combustion engines, on its own, or blended with other fuels. Bio-oils are a complex mix and generally require a series of treatment processes that involve hydrogenation to remove oxygen, nitrogen and sulphur to improves their physical qualities. The hydrogen addition is, however, modest, at 12% of the biomass input (on the lower heating value) for HTL and hydrotreated vegetable oils (HVO) [83] and should not be confused with the secondary conversion (used to increase yields) discussed in Section 5.3.

In the HTL process, biomass and water are heated at high pressure to produce a stable bio-oil with high energy content and low oxygen that may be processed in existing oil refineries due to its similarities with fossil oil [91] or used directly in shipping to replace marine gas oil (MGO). Several variations of pyrolysis exist, and known configurations include fast pyrolysis and catalytic hydropyrolysis [83]. Fast pyrolysis bio-oil has a high oxygen content with a relatively low energy content [92], and its deoxygenation potential makes it uncertain for commercial-scale applications [93].

Catalytic hydropyrolysis deals with this issue and produces a more stable bio-oil with low oxygen content and higher energy content, making it more similar to the fossil equivalents.

Hydroprocessing produces HVO and hydroprocessed esters and fatty acids (HEFA) and, as with HTL and pyrolysis, involves a certain level of hydrogen to improve the physical qualities of the product. HVO is also known as renewable diesel, a fuel with superior qualities to fossil diesel, while HEFA is one of the few certified bio-jet fuels that can already be blended up to 50% with fossil jet fuel [94].

Transesterification uses similar feedstocks to those used in hydroprocessing, and its product is also known as bio-diesel; however, instead of hydrogen, it uses methanol or ethanol as reactants [83]. Ethanol is also the product of fermentation from sugar and starchy crops and is currently used in blends with gasoline or on its own.

The briefly described biomass conversion processes are compatible with certain biomass types, as illustrated in Table 1. Some biomass types, such as agricultural residues or energy crops, have more extensive compatibility with more biomass conversion technologies, but they are all dependent on the overall biomass availability.

Table 1: Biomass conversion technologies and the feedstocks they use.

	Woody biomass	Solid agri. residues	Manure	Organic waste	Sludge	Energy crops	Veg. oils, fats
Anaerobic digestion		X	X	X	X	X	
Thermal gasification	X	X				X	
Hydrothermal liquefaction	X	X	X	X	X	X	
Pyrolysis	X	X				X	
Hydro-processing						X	X
Transesterification						X	X
Fermentation		X				X	

Woody biomass is suitable for thermal gasification, HTL or pyrolysis at comparable efficiencies [83], producing either gaseous or liquid fuel outputs. Woody biomass can originate from forestry products, including tree plantation waste and wood residues.

Solid agricultural wastes are mainly residues from agricultural cultivation and are one of the two types of biomass compatible in all conversion processes except for those including oily and fat inputs. Straw is the most common resource in this category and is often referred to in connection with biogas plants, where it can increase yields. However, straw may be used on its own for the production of syngas, bio-oils or bio-ethanol.

Manure, organic waste and sludge are categorised as waste products, albeit with good potential for conversion to fuels in dedicated facilities, such as anaerobic digestion or HTL. These waste products are often associated with high GHG emissions and other hazardous effects, so waste treatment is essential.

Energy crops are grown explicitly for energy purposes and may be used in all mentioned biomass conversion processes, depending on the energy crop type. Sugar and starch crops are specific inputs in 1st generation ethanol, while oily crops can be used in hydroprocessing or transesterification. Other crops, like willow, poplar or grassy crops, are suitable for the other conversion processes that can deal with lignocellulosic biomass.

The feedstock availability differs for each of the conversion processes, as illustrated previously in Figure 6, and it is one of the factors that can shape a technology's large-scale deployment. A defining factor is the type of output, i.e. gaseous or liquid, which will influence the end-use applications. Regarding flexible operation, such equipment is typically kept in continuous operation as the potential for regulation is often limited [83] or unnecessary, depending on the end-use of the products.

Among the technologies described above, anaerobic digestion, hydroprocessing and transesterification are generally commercially available technologies, even though further optimisations are necessary for using new feedstocks, e.g. straw in biogas and bio-ethanol plants [83,95,96]. Thermal gasification has been demonstrated for a long time in Denmark and abroad [97,98], mainly connected with electricity and heat production, but the technology still needs to overcome technical and non-technical barriers before entering the market [83,99]. HTL and pyrolysis are both in the early development stages, with further research needed before any commercial units can be deployed [83,91].

Not all biomass conversion technologies are analysed throughout the three studies. Anaerobic digestion takes a central role in Study 1, while thermal gasification is central to Study 2. Both technologies are analysed in Study 3, including HVO, but future analyses should include all technologies.

5.2.3 CARBON AND NITROGEN CAPTURE

Another key technology for the production of electrofuels is carbon capture. Carbon capture (CC) has received attention due to its potential to store carbon emissions from various emitters through carbon capture and storage (CCS), or to provide a carbon source for fuel production syntheses, i.e. for CO_2-electrofuels, also known as carbon capture and utilisation (CCU).

Among the existing point-source CC technologies, two categories stand out: post-combustion and oxyfuel combustion. As the name suggests, post-combustion technology captures CO_2 emissions after the combustion stage. It can be installed as an add-on to existing combustion plants, making it suitable for retrofitting purposes. Amine-based capture is the most developed of the post-combustion technologies, with a wide range of applications from power plants, industry to biogas upgrading with flexible load cycling. On the downside, the technology is energy-intensive and has a high standard for upstream flue gas cleaning, which results in high operational and investments costs [23], although synergies with local heating infrastructure integration may be possible [100].

Oxyfuel combustion operates by replacing the air in the combustion chamber with oxygen, thus enabling a nitrogen-free stream of CO_2 for capture [23]. It is well-suited to cement production since both processes are operated at continuous load [100]. Due to the high emissions from the calcination process, the output of captured t_{CO2}/t_{O2} input is high but comparable with a post-combustion setup. Since oxygen production is one of the main capital costs of this technology, it may find synergies with oxygen from electrolysis.

Other technologies exist, such as direct air-capture (DAC), which essentially captures carbon from the air. The advantage of this technology is that it can be installed almost anywhere and can be a method for decoupling the carbon source location from the production of electrofuels or providing access to lower electricity and heat prices [23,101]. From a cost perspective, DAC may not be competitive with point-source capture due to the significantly higher energy consumption (heat and electricity) and the high investment costs. As a comparison, post-combustion capture is expected to reach a cost as low as 200 €/tCO_2 by 2050 in cement kilns with the constant annual operation, while the same source finds the investment cost in DAC to be 500 €/tCO_2 [23]. However, other authors estimate that this cost may be comparable with point-source capture in the long-term [101].

An alternative to producing renewable hydrocarbons is producing ammonia. Ammonia combines hydrogen from electrolysis with nitrogen from the air. Nitrogen is the most abundant component in the air, and it can be captured by air separation units (ASU), which also gives the technology more flexibility in regards to the location of fuel production. An ASU is also a less expensive component of the electrofuel plant than carbon capture, and its cost is estimated to be not more than 10% of an ammonia plant (excluding electrolysers) [83].

5.3 SECONDARY CONVERSION

After the primary conversion stage, the resulting products may be used directly in stationary applications or upgraded to other fuels. This section deals with upgrading these products to refined fuels, with and without hydrogenation, to illustrate the diversity of the pathways and the associated challenges. It starts with the possibilities for upgrading from biogas, then moves to the upgrading possibilities from syngas and bio-oils.

5.3.1 BIOGAS CONVERSION

Anaerobic digestion in biogas plants can be coupled with purification or methanation. In the purification process, CO_2 and other impurities are removed from the biogas via scrubbing or pressure swing adsorption, leaving only the biomethane compound in the gas [83]. Since it does not involve electrolysis, the flexibility of this process is not very important, especially as gas can be stored in the existing gas grids.

Methanation achieves a similar product to biomethane but uses electrolysis to combine CO_2 with hydrogen to produce methane. Methanation to electromethane is a more expensive upgrade than purification to biomethane, but the former has a higher yield with the same biogas input. Two types of methanation reactors exist, namely biological and catalytical. Biological methanation operates at 20-70 °C and ambient pressures, while catalytic methanation occurs at over 200 °C, making the latter highly exothermic, which correlates with higher reaction rates but also more synergetic possibilities due to waste heat integration [102].

Both types of methanation appear suitable for flexible operation, reducing costs with hydrogen storage on the electrolyser side. However, due to the slower reaction rates of biological methanation, this would require significantly larger reactor sizes, making it unsuitable in large-scale applications [102].

5.3.2 SYNGAS CONVERSION

Syngas from thermal gasification can be upgraded into various products since its basic components include hydrogen, carbon dioxide and carbon monoxide. The main difference between the hydrogenated and non-hydrogenated pathways is the increased yields that the former can achieve while using the same biomass inputs, which is an essential aspect in the context of limited biomass resources. A stoichiometric H_2/CO ratio defines the necessary balance between the two components, which can be adjusted through the addition of hydrogen or the removal of CO_2.

The CO_2-hydrogenation pathways, for which the carbon does not originate from biomass, but carbon capture, the H_2/CO stoichiometry can be achieved by adding electrolytic hydrogen. From this point on, the fuel syntheses are similar and thus described together. Syngas can be upgraded to three types of outputs:

- Methane
- Methanol
- Fischer-Tropsch liquids.

Methane production occurs through a methanation process similar to the one used with biogas, and the same types of reactor characteristics apply.

Methanol production takes place in chemical synthesis with an H_2/CO stoichiometric ratio of 2. As in the case of methanation, the reaction is exothermic, operating at over 300°C and offering similar waste heat integration potentials. When coupled with biomass gasification, waste heat can be used for feedstock drying [103] or as a heat source for carbon capture. Like methanation, methanol synthesis is also suitable for flexible operation [104], which may be a significant advantage considering the necessity for reduced electrolyser full load hours or the cost of hydrogen storage. However, the flexible operation may impede heat integration.

The production of Fischer-Tropsch (FT) liquids requires a stoichiometric H_2/CO ratio slightly higher than 2 to produce a range of outputs, but this can be optimised towards the desired fuel, generally diesel or jet fuel. However, the production also incurs potential trade-offs regarding the production rate as co-products like naphtha, petrol, ethanol and methane are always produced. Moreover, compared to other fuel syntheses, FT is the least flexible regarding load changes or frequent start-ups due to the high temperatures and pressures it operates at [83], which may weigh heavily in the choice of syntheses.

5.3.3 ADDITIONAL SYNTHESES

Apart from these reactions, further refining can be achieved. Methanol can be upgraded to dimethyl ether (DME), petrol or jet fuels with a specific energy penalty of up to 25% [88,105]. There are also bridging possibilities between the pathways mentioned above, such as in the gas to liquid (GTL) processes, regarding the reforming of methane into syngas or hydrogen through steam methane reforming (SMR) or partial oxidation (POX); however, this comes with an energy penalty, estimated at 10-15% of the produced syngas [37] or lower for hydrogen.

Another upgrade pathway may involve refining the co-products from bio-oil production to more refined fuels, such as methanol, methane or FT liquids. For HTL or pyrolysis, the gas by-product is a mix of CO_2 and H_2 that can be preconditioned and adjusted to the correct stoichiometric ratio for methanol or FT production through the addition of electrolytic hydrogen. The existing literature dealing with this aspect is somewhat limited, focusing primarily on the potential of negative emissions [106,107]. Hannula et al. [92] performed an assessment of hydrogen enhanced methanation in connection with pyrolysis, showing the potential of this technology combination, which can be considered an extension to the definition of bio-electrofuels.

5.4 STORAGE

Fuel storage is an important consideration when replacing established fossil liquid and gaseous fuels with new fuels with different chemical and physical properties. Storage can take place both on-board vehicles or on land, for instance, in proximity to the production site or at large transport nodes such as ports or airports.

Fossil fuels have high volumetric and gravimetric densities, making them cheap to store, particularly in a liquid state. Gaseous fossil fuels such as methane are slightly more expensive to store because they require pressurised storage. In any case, both liquid and gaseous fuel storage methods are currently used to store refined oil products and natural gas. Nevertheless, the discussion regarding on-land storage must extend to the infrastructure requirements to supply these fuels and the transport modes that will be using them.

The production of new fuels should account for existing infrastructure, the deployment of new infrastructure, all at the lowest possible cost and in close synergy with the other parts of the energy system [108]. The available types of fuels that may be produced in the future can be categorised into four types, based on the type of storage they use:

- Liquid fuels
- Low-pressure compressed gaseous fuels
- High-pressure compressed gaseous fuels
- Liquefied gaseous fuels

5.4.1 LIQUID FUELS

The liquid fuel category includes all fuels produced as liquids and remain in a liquid state at standard temperature and pressure (STP). This category includes methanol, FT liquids, jet fuel, bio-oils, ethanol and bio-diesel. For all these fuels, the storage requirements are similar to existing fossil liquid fuels, such as oil, diesel or petrol, as they only require steel tanks. The infrastructure for delivering and fuelling vehicles can, in many cases, be adapted from existing fossil fuels at low cost [109,110]. Many of these fuels are also suitable for blending with fossil fuels, which may be a path for introducing renewable fuels into the transport sector.

5.4.2 LOW-PRESSURE COMPRESSED GASEOUS FUELS

Low-pressure compressed gaseous fuels include methane, biogas, syngas and transport fuels such as DME and ammonia. Biogas and methane are suitable for stationary applications and require several bars of pressure for storage in tanks. Methane can also be stored in the natural gas grid or underground storage. The natural gas network and underground storage facilities are relatively widespread in Europe, making methane transport and distribution a cost-effective solution [111]. Biogas storage is similar to methane storage, except that it poses difficulties for underground storage due to CO_2 contamination, acidifying underground water sources [112]. However, biogas may be stored in low-pressure tanks suitable for use in connection with power and heat production [113].

Syngas (also known as producer gas) is the fuel produced from the thermal gasification of biomass and can be used in stationary applications with 10-20 bars of pressure. It requires specialised types of storage as it contains hydrogen, which may cause metal embrittlement. Due to the low energy content per volume caused by the CO and CO_2 presence (as in the case of biogas), it also needs larger storages than methane and may pose difficulties for underground storage [114].

The storage requirements for transport fuels are slightly different. DME and ammonia are gaseous fuels at STP but require a moderate pressure increase to be stored as liquids. These become liquid at low pressures of up to 10 bars, e.g. similar to fossil LPG (liquefied petroleum gas) [115]. Depending on the ambient temperature, it is common to increase the pressure to higher values to keep the fuel in liquid form. Unlike DME, ammonia is toxic, so that additional handling costs may arise for this type of fuel. However, ammonia is a commodity handled for many years, and thus, there exists considerable experience and knowledge.

5.4.3 HIGH-PRESSURE COMPRESSED GASEOUS FUELS

The category of high-pressure compressed gaseous fuels includes methane and hydrogen. Methane can be stored at low pressures for use in stationary applications, but its transport use requires a new fuelling infrastructure capable of storing and compressing methane at the demand location. The electricity input for compressing the methane can be estimated at 0.025 kWh_{el}/kWh_{CMG} [20], and compressed methane gas (CMG) requires approximately 200 bars of pressure when stored on-board vehicles [116]. The high pressure is necessary to increase its volumetric density, even though this still leaves it one quarter as dense as petrol and half as dense as methanol.

Hydrogen is another fuel that requires high pressures in both stationary and on-board storages, albeit at different levels. For use in automotive applications, the pressure varies between 350 and 700 bars due to the low volumetric density [117], also implying a significant electricity consumption, between 0.03 to 0.04 kWh_{el}/kWh_{H2}.

Hydrogen transport and fuelling infrastructure may pose other challenges, even though there has been some discussion of converting the natural gas grid to a hydrogen grid [118]. However, this solution faces significant technological limitations, which makes the cost significantly more uncertain.

5.4.4 LIQUEFIED GASEOUS FUELS

The category of liquefied gaseous fuels also includes methane and hydrogen. The storage requirements are different from the other liquefied fuels such as ammonia or DME due to the significantly higher energy requirements for liquefying methane and hydrogen. Electricity consumption for liquefaction reaches 0.06 kWh_{el}/kWh_{LMG} and 0.25 kWh_{el}/kWh_{H2} [35], with considerable associated investment costs [119].

Liquefaction of such fuels is necessary to improve their volumetric energy density in applications such as heavy-duty long-distance road transport, shipping or aviation. Even liquefied, liquefied hydrogen (LH_2) remains half as dense as methanol, while LMG is one third as dense as LH_2.

5.4.5 SUMMARY

The order in which the five types of storages are represented in this chapter is also, in most cases, their cost order: liquid fuels have the lowest cost while high-pressure compressed gaseous fuels and liquefied fuels have the highest cost.

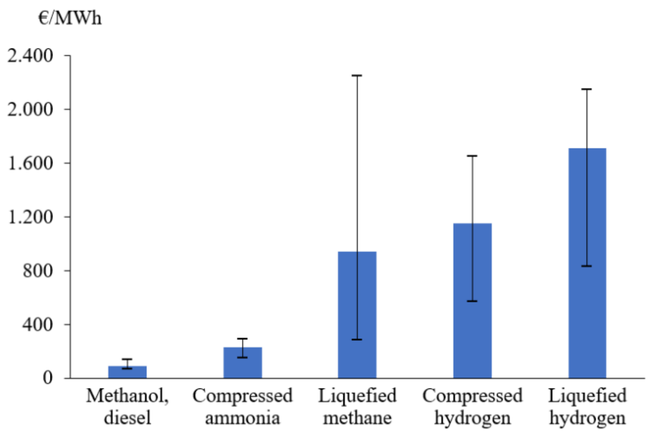

Figure 7: Overview of current and near-term fuel storage estimates from the literature mainly connected with shipping [120–125].

Figure 7 presents the on-board fuel storage costs related to the shipping sector, with inputs from automotive-related studies to illustrate an example of the cost differences. The costs refer to current and near-term estimates towards the year 2030 and specify the investment cost solely in terms of storage tanks and not the storage system, which may incur additional costs with auxiliary equipment. This illustration aims not to point to a specific cost level for any of the fuel storages, as the literature estimates are very diverse, but rather to show the differences between the different types of fuel categories and related storages.

Several key observations can be made using this figure. First, one can observe several orders of a magnitude cost difference between liquid fuels and high-pressure compressed and liquefied fuels, with the median estimates at a 10-20 times difference favouring the former. Second, the range of uncertainty for compressed and liquefied fuels is much broader than for the category of liquid or moderately compressed fuels. Third, the fuels that entail significant energy consumption for compression or liquefaction also have high storage costs.

Such cost differences are also reflected in the cost of fuel distribution and fuelling infrastructure. On the shipping topic, Taljegård et al. [122] estimated the investment cost of fuelling infrastructure in ports at 100-200 $/kW for liquid fuels and between 1600 and 2100 $/kW for LMG and LH_2. Helgeson and Peter [35] also estimate that even towards the year 2050, both compressed and liquefied hydrogen infrastructure for road transport will remain ten times more expensive than gasoline or diesel. These are essential aspects to consider in the future choice of fuels.

5.5 UTILISATION

Fuel end-use is a critical aspect that influences the overall cost of future energy systems, electricity cost, the total cost of ownership and fuel demands. Therefore, the cost- and energy-efficient utilisation of renewable fuels must be an integral part of a well-designed renewable fuel production value chain. Renewable fuels will likely have applications in all sectors of future energy systems, albeit with a reduced consumption compared to today, due to large-scale electrification. Moreover, the distribution of renewable fuels between energy sectors will also change; heating serves as a prime example, as future energy systems should use waste heat and heat pumps, as per the Smart Energy System design. However, some parts of power production, industry and transport will continue using fuels.

The power and heat sectors typically operate on gaseous fuels, apart from solid fuels like biomass, which can be used directly in power plants. The same applies to the industrial sector, where the fuel demands may also be supplied by similar gaseous fuels, which are more common than liquid fuels. For the transport sector, there can be a mix of liquid and gaseous fuels.

5.5.1 POWER AND HEAT PRODUCTION

In the power and heat production sectors, biomass is already a common fuel, often used in retrofitting old coal plants. While this solution is often in easy reach for slashing CO_2 emissions quickly, existing research [126] has found that the direct use of biomass in power plants is neither very efficient nor very flexible. Future energy systems will thus require robust units that can deal with variable wind and solar production. While combined cycle gas turbines (CCGT) can be suitable for this task due to their high efficiency and potential for flexible operation, other technologies such as fuel cell CHPs may also fill this role, but without the same level of flexibility [68]. In both cases, any gaseous fuels may be used for this purpose, ranging from biogas, syngas, and methane to hydrogen.

5.5.2 INDUSTRY

The industrial sector may use the same fuels as power and heat production, although this may require a lower level of flexibility due to the nature of the demands. Large segments of the fuel consumption in the industry cannot be included in balancing the supply and demand but instead operate on pre-determined schedules or even continuously.

Fuel quality can be another consideration for the industry that may eliminate some fuel options such as biogas or syngas from direct usage. This means that more refined fuels such as methane or hydrogen would supply the demands, which is also the assumption in the most ambitious scenarios of the EU's long term strategic vision [34]. Methane can replace natural gas in the same applications as today, provided that electrification and energy savings reduce the renewable fuel demand sufficiently. On the other hand, hydrogen may also be an alternative fuel and is already deployed in the iron and steel industry in Sweden [127].

5.5.3 TRANSPORT

Liquid fuels are typically used in the transport sector, but it is also common to use compressed or liquefied gaseous fuels. These require internal combustion engines (ICE) or fuel cells (FC). ICEs combust the fuel in spark or compression engines for road and shipping, while aviation uses mostly jet turbines. FCs generate electricity through a thermochemical reaction, which in turn powers an electric motor.

Road transport has the widest variety of renewable fuel options, and apart from battery-electrification, which has the best potential in this sector [51], vehicles can use diesel, gasoline, HVO, methanol, DME, ethanol, methane or hydrogen in four-stroke ICEs. Some of these fuels, namely methanol, methane or hydrogen, can also combine with polymer membrane fuel cell (PEMFC), but methanol and methane will also require a reformer to convert the hydrocarbon to hydrogen. High-temperature PEMFC is the most mature technology among the existing FCs in transport, but other options exist, such as solid oxide fuel cells (SOFC), which do not need reformers but are less tolerant to load changes and are technologically less developed [128].

The majority of the fuels used in road transport are also suitable for shipping, except for gasoline or ethanol. Conversely, ammonia is suitable in shipping, being the only transport sector that can handle this fuel due to its high toxicity. ICEs are the primary type of propulsion today and are split into four-stroke and two-stroke engines. Four-stroke engines are often found in smaller ships on short distances and where onboard space is limited, while two-stroke engines are usually combined with large ships due to their higher fuel efficiency. Apart from ICEs, future ships may also operate with high-temperature PEMFC or SOFC, similar to road transport.

Aviation requires a specific range of fuels and propulsion systems. The only currently viable replacement for fossil jet fuel is renewable jet fuel, which has a similar chemical composition as its fossil counterpart. The quality requirements for jet fuels are very high, and only a few renewable jet fuels are certified. Those certified are HEFA and FT jet fuels, exclusively sourced from biomass, but other pathways may soon receive certification [94].

6 THE THREE STUDIES

Chapter 5 described the components for renewable fuel pathways, including the challenges arising with the choice of various technologies. It also demonstrated that a variety of technologies must be considered when designing future renewable fuel pathways. In addition to the literature review performed in Chapter 1, this can be summed up as a part conclusion: that no single technology or fuel pathway can solve the issue of replacing fossil fuels efficiently and within biomass constraints; rather, a mix of multiple solutions will be necessary. This chapter aims to determine which are the feasible renewable fuel pathways that can integrate with future sustainable energy systems. The three research articles included in this dissertation combine the components defined in the previous chapter to identify the role of technologies in a variety of scenarios and sensitivity analyses.

The first two research articles [1,2] use energy system analysis and deal primarily with the first part of the pathways, namely resources, primary and secondary treatment, with an overview of storage and utilisation. They inquire into the roles of different types of biomass and biomass-based fuels in the context of resource limitations and costs for all energy sectors while also incorporating the role of CO_2-electrofuels. The third study [3] deals primarily with the other end of the pathways, namely the primary and secondary conversion of resources, storage and utilisation. This study focuses on the maritime transport sector. An illustration of the contribution from the three studies is shown in Figure 8. The three studies differ in terms of their geographical focus, with Study 1 dealing solely with the Danish context, Study 2 addressing both Denmark and the EU, while Study 3 takes a global approach, albeit still with a Nordic perspective.

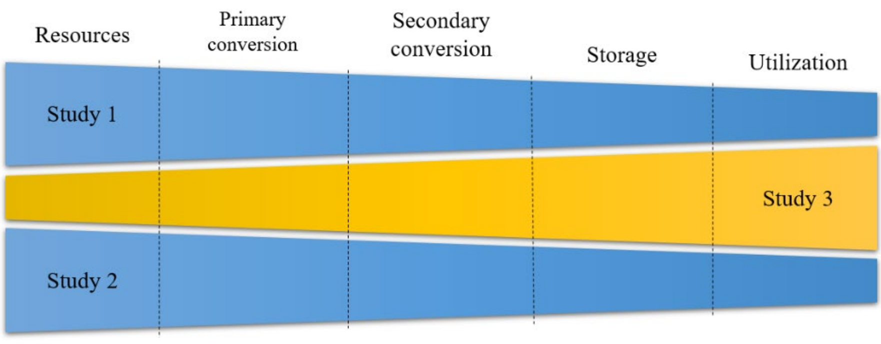

Figure 8: Illustration of the value chain links analysed throughout the three studies.

The three studies are further attached in this chapter on pages 44, 56 and 75.

6.1 STUDY 1 - THE ROLE OF BIOGAS AND BIOGAS-DERIVED FUELS IN A 100% RENEWABLE ENERGY SYSTEM IN DENMARK

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The role of biogas and biogas-derived fuels in a 100% renewable energy system in Denmark

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ABSTRACT

In this paper, we analyse the role of biogas and biogas-derived fuels in a 100% renewable energy system for Denmark using the energy system analysis tool EnergyPLAN. The end-fuels evaluated are biogas, biomethane and electromethane. First, a reference scenario without biogas is created. Then biogas, biomethane and electromethane replace dry biomass-derived fuels in different sectors of the energy system. The results show that biogas and biomethane reduce dry biomass consumption by up to 16% when used for power, heat or industrial sectors. If biogas feedstock is free for energy purposes, this brings significant energy system cost reductions, but when the energy sector pays for the biogas feedstock, then savings are lower, in which case biogas and biomethane still reduce the energy system costs for use in power, heat or industrial sectors. Replacement of liquid bio-electrofuels for transport with biomethane shows slight cost reductions, but considerably higher costs when using electromethane. For power, heat, industry and partly transport, electromethane is economically unfeasible, independent of the dry biomass costs. Biogas should be used directly or in the form of biomethane. It is a limited resource dependent on the structure of the agricultural sector, but it can supplement other renewable energy sources.

1. Introduction

Shifting from a conventional fossil-based energy system to 100% renewable energy systems presents significant challenges, but the technical feasibility of such systems is within reach [1–3]. One of the difficulties in designing such energy systems lies in the choice and utilisation of future technologies and fuels. Such a future fuel is biogas, a fuel produced by various biodegradable materials such as the organic fraction of municipal solid waste, livestock manure, energy crops and in some cases agricultural products, such as straw. In the case of Denmark, the most abundant feedstock is livestock manure, together with energy crops like corn and beets [4].

The Danish production of biogas from different resources is expected to increase in the future from 13.4 PJ in 2018 [5] to levels between 23 and 107 PJ, as illustrated in Fig. 1, depending on the technology advancements, including methanation of biogas, according to Gylling et al. [6]. Other literature reports also provide a wide range of the potentials indicating that different methodological assumptions can lead to different results [7–11]. These publications find the most significant potential in green biomass, like grass and beet followed by manure and straw, which all are suitable for biogas production.

In Denmark, there are currently 163 biogas plants, of which 50% use agricultural products, 31% sewage residues, 3% industrial products and 16% are using landfill gas. The first full-scale biogas upgrading plant from the wastewater treatment plant was established in Fredericia in 2011 [12]. As of 2018, electricity used 46% of the biogas production, heat production used 3%, while the gas grid took delivery of the rest, to use in industry and transport [13] (Fig. 1). Today, the gas network takes delivery of biogas from 33 biogas plants [14], making Denmark the country with the highest share of biogas in the gas consumption in Europe at 18.6% [15].

Since biogas has a long tradition in Denmark, the research covered on the topic of biogas from different perspectives, with only the most relevant for the current analysis selected for the literature review. Among them, in 1999, Mæng et al. [16] assessed the socio-economic cost of technological development in terms of biogas prices in Denmark noticing the steep cost reduction. Raven and Gregersen [17] explained the reasons behind the extensive Danish biogas development, providing as reasons the political

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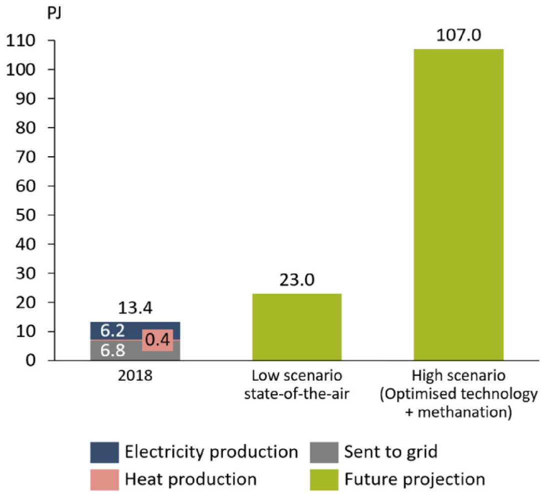

Fig. 1. Biogas production and utilisation in 2018 [5] and future potential [6].

stimulation as well as the strong policies for decentralised combined heat and power (CHP) production coupled with the preference of farmers to collaborate in small communities. By using energy system analysis, Münster and Lund [18,19] find that biogas and thermal gasification are better alternatives than using the same feedstock for incineration. Going further, Münster and Meibom [20] find out that biogas is better suited for use in CHP or transport in a scenario with 48% renewable energy for the year 2025. Bojesen et al. [21] addressed the problem of location and production capacity for biogas, finding out that large-scale biogas plants are preferred since they minimise the most significant cost component in biogas production: feedstock transport. On the demand side, Jensen and Skovsgaard [22] studied the impact of varying CO_2 costs on biogas use for power production, while Cong et al. [23] performs a full economic and environmental assessment for using biomethane as a fuel for transport, finding out that biogas can be a useful tool for reducing CO_2 emissions in the transport sector. Concerning the transport sector, Hagos and Ahlgren [24] assign upgraded biogas a critical role in the transition to a decarbonised energy system. In another decarbonisation context, Jensen et al. [25] find that upgraded biogas is key to transition electricity and district heating systems. Other studies included biogas in the analysis of 100% renewable energy systems but focused on the design of these systems instead of analysing biogas in detail [11,26,27].

Outside the Danish context, some studies inquired the potential of using biogas in the Swedish transport sector [28,29], biogas as an intermediate between wastewater plants and district heating systems [30] and one study performs an energy system analysis on the end-use of biogas, comparing biogas in transport and district heating [31]. Hakawati et al. [32] that used LCA (Life Cycle Analysis) to determine if the utilisation of biogas should be for electricity production, heat production or transport. Their results indicate that biogas should be used directly when possible, but biomethane competes well and has the advantage of more accessible transportation in the gas grid (if in place) as well as more types of applications. In the transport sector, gas engines still suffer from low efficiencies, so the authors do not recommend gas engines before electric vehicles. The analysis done by Hakawati et al. [32] provides a solution to fuel consumption from an efficiency perspective, but it does not assess the impact for biomass utilisation nor does it make an economic assessment of the choices made.

The literature review revealed that none of the studies assessed the role of biogas and its derived fuels in the context of 100% renewable energy systems. This context is relevant due to the future competition of biogas with other renewable fuels which will rely on biomass feedstock, a limited resource in the future. None of the studies performed a cost assessment of the fuels in a future context where the use of biogas may be different from today. This study aims to fill these gaps by performing both a technical and economical energy system analysis for Denmark which aims to indicate the most efficient use of its significant biogas potential.

2. Methods and materials

The design of 100% renewable energy system requires high temporal and data granularity tools that can encompass all the energy system sectors. Such tools enable improved decision making in regards to the choice of fuels, technologies and design of the future energy systems. EnergyPLAN was the tool of choice to perform this analysis because it includes the balancing of the energy system in its fuel cost calculations. The tool operates on an hourly resolution based on the principle of cross-sector integration, enabling the results to be more comprehensive than simulating the energy sectors isolated from each other.

A reference system model is set up with the tool as one potential version of a 100% renewable energy system model for Denmark in the year 2050. The reference system uses on the original model prepared in IDA Energy Vision 2050 report [11] that in its turn was developed using the concept of Smart Energy Systems. The concept of Smart Energy Systems entails that an energy system is 100% renewable, uses a sustainable level of bioenergy, makes use of the synergies between energy grids (electricity, thermal and gas) and energy storages and is affordable [33]. The IDA Energy Vison 2050 [11] aimed at building the model using this concept.

For this analysis, the reference model was adapted to accommodate an energy system without any biogas production. The reference system and the scenarios are analysed with technical simulation, meaning that the tool operates to minimise the fuel consumption, an important metric that determines the efficiency gains of using different forms of fuel. The analysis conducted uses costs that reflect technology investment costs stripped out of taxes and subsidies (the same applies to O&M) and is intended to be a socio-economic assessment in which the use of one fuel or another is assessed based on its impact on the energy system and society rather than its value stream and market potential.

In the reference system, variable renewable energy sources like wind and solar dominate and produce 85% of the electricity in the energy system. The rest comes in equal shares from power plants and CHP fuelled by methane from biomass gasification. In the heating sector, district heating supplies two-thirds of the heat demands while the remaining demands are supplied mainly by individual heat pumps. Electromethane produced via biomass gasification with hydrogen addition (biomass hydrogenation) provides 70% of the industry demands while the remaining share is covered by biomass directly.

The tool simulates all scenarios as a closed system, independent of fuel imports. Other energy system boundaries include an excess electricity production limited to 10% of the domestic electricity demand and gas balance to be 0, meaning that the total gas demand matches the total gas production over the year.

In the transport sector, priority is given to electrification and compared to the IDA Energy Vision 2050 [11]personal transportation has a higher degree of electrification. Table 1 provides an

Table 1
Main parameters of the reference system in EnergyPLAN based on [11].

	Unit	Reference scenario
Primary energy supply		
Onshore wind	TWh/year	16.20
Offshore wind	TWh/year	53.06
PV	TWh/year	6.35
Wave	TWh/year	1.35
Biomass	TWh/year	59.73
Conversion capacities		
Onshore wind	MWe	5,000
Offshore wind	MWe	16,650
PV	MWe	5,000
Wave	MWe	300
Large CHP	MWe	3,500
Small CHP	MWe	1,500
Power plants	MWe	4,500
Electrolysis	MWe	8,784
Energy demands		
Domestic electricity	TWh/year	36.36
Electricity for electrolysers	TWh/year	37.22
Electricity for transport	TWh/year	9.43
Electrofuel transport	TWh/year	29.78
Industry	TWh/year	11.82
DH demand	TWh/year	28.19
Individual heating	TWh/year	14.51

overview of the supply, conversion and demands of the chosen energy system.

2.1. Biogas utilisation scenarios

There is a high versatility for biogas as intermediate and end-fuel in all energy sectors and the production has grown exponentially in the past years in Denmark due to the strong political support [34]. Biogas as intermediate or end-fuel is a potential carbon-neutral solution feasible for all energy sectors, but it also a solution that needs to compete with other fuels and technologies and is a limited resource. The case of utilising biogas (or any gas) in the heating sector for individual gas boilers has been analysed before, for both Denmark and the European Union. Results demonstrated that solutions in the form of district heating and individual electric heat pumps present better alternatives due to their potential to reduce energy system costs and biomass consumption, improve sector coupling and allow for the utilisation of new heat sources [35–38]. Therefore, the analysis does not investigate biogas and its derived fuels for individual heating.

In order to determine the utilisation costs and the energy system effects of different forms of biogas and its derived methane products, eight scenarios were created and compared to the reference scenario. These scenarios have the role of testing how each selected fuel (biogas, biomethane and electromethane) performs in each energy sector (electricity, district heat, industry and transport) and determine which combination of fuel-energy sector has the lowest cost and is the least biomass intensive option. The results of this analysis can provide indications where biogas should be used in a future context where fossil fuels do not exist anymore and where there will be other fuels and competing technologies.

Throughout the analysis, biogas and its derived methane products are referred to as *biogas* as raw biogas without any downstream treatment, *biomethane* from biogas purification and *electromethane* from biogas methanation with the addition of electrolytic hydrogen. Fig. 2 illustrates the utilisation overview.

The different biogas scenarios are built starting from the reference system by displacing other types of methane and liquid bio-electrofuels as follows:

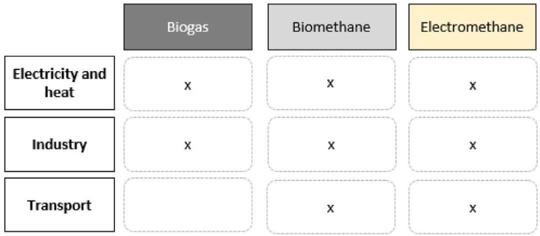

Fig. 2. Utilisation overview matrix.

- In the biogas scenarios, raw biogas is substituting gasified biomass in electricity and heat production and substituting methane from gasified biomass in industry. Having a scenario where biogas replaces gas in the industry is not fully representative, as it is likely that biogas alone cannot supply all demands in the industry, but it was included to demonstrate the utilisation costs.
- In the biomethane scenarios, biomethane is substituting gasified biomass in power production, methane from gasified biomass in industry and liquid bio-electrofuels in the transport sector.
- In the electromethane scenarios, electromethane is substituting gasified biomass in electricity and heat production, methane from gasified biomass in industry and liquid bio-electrofuels in the transport sector.

Several criteria were used to find the right biogas, biomethane and electromethane demand for the analysis. First, the reference system was analysed using a selection of electromethane demands in with different electrolysis configurations. The results show that the marginal cost difference increases with higher electromethane production in the system but also grows when adding additional electrolysis capacity and storage. However, if the system produces 8.41 TWh (~30 PJ) of electromethane, the costs are nearly the same for electrolysis with baseload capacity and the electrolysis with 100% buffer capacity including seven days of hydrogen storage as shown in Fig. 3. If we then compare the biomass demand and wind production for this specific case, it is visible that the system with additional electrolysis capacity and storage brings a reduction in biomass consumption and an increase in wind production. Therefore, this capacity represents both a 100% renewable energy system with high wind penetration as well as an energy system with no buffer capacity and no storage.

Secondly, the 8.41 TWh fuel demand is equal to the methane demand in the industry sector of the reference scenario, which allows for the simulation of the same gas demand across all energy sectors. All scenarios have the same gas demand for electricity and heat, industry and transport that is supplied either with biogas, biomethane or electromethane. Lastly, the 8.41 TWh are in line with the more conservative biogas production estimates in various literature sources, as presented in the Introduction.

The analysis done by Mathiesen et al. [11] provides the basis for the vehicle mix the reference scenarios, but the new scenarios needed a new propulsion mix with biomethane and electromethane in transport, so gas engines replaced traditional combustion engines in buses, trucks and commercial vehicles (2–6 tonnes). According to the source used for this study [39], the vehicle efficiencies for gas engines do not differ considerably from their liquid fuel counterparts.

The transport tool TransportPLAN [40] was used to create new transport demand projections. EnergyPLAN then uses as input data

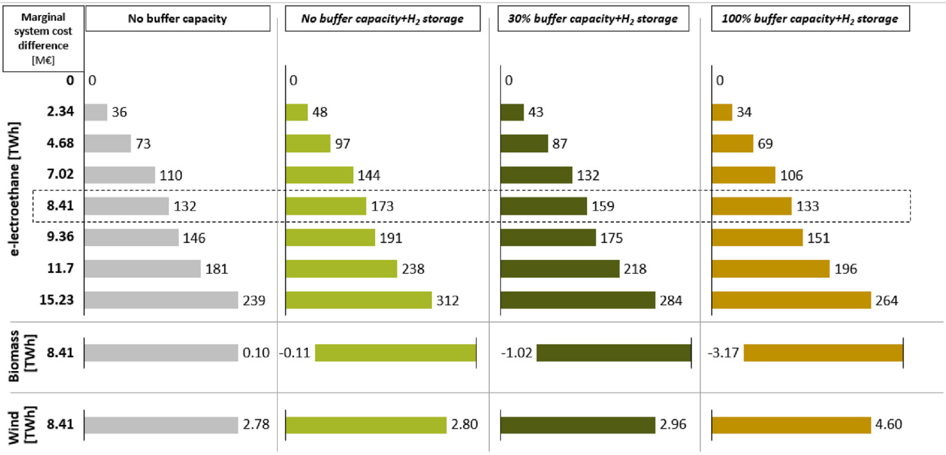

Fig. 3. Marginal energy system cost difference in M€ for different levels of electromethane (upper), biomass consumption in TWh (middle) and wind production in TWh (bottom) for different electrolysis configurations.

the output data produced by TransportPLAN. The new scenarios account for the change in vehicle costs when gaseous fuels supply their part of the transport demand. Table 2 presents the division of fuels per types of road vehicles in the scenarios with methane in the transport sector:

In the scenarios for the transport sector, both biomethane and electromethane require gas compression, so the demands include 2% compression losses, which in turn requires an increased amount of feedstock in the biogas plants to achieve the fixed demand of 8.41 TWh used throughout the scenarios. The new demands of biomethane and electromethane used in the transport sector, in their respective scenarios, substitute more than 80% of the liquid bio-electrofuels in the reference scenario. The rest of the substituted fuels are liquid CO_2-electrofuels produced through carbon capture and utilisation. Using this approach was needed as there were not enough bio-electrofuels in the reference scenario to replace without affecting the electrified transport demands, considered more efficient and not to be replaced by less efficient vehicles.

The scenarios with biomethane and electromethane in transport sector also include different costs for vehicles in comparison to the reference scenario, as gas vehicles are found more expensive than vehicles running on methanol or DME [39]. Separate from the vehicle costs, an additional annualised cost of 108 M€ was included to reflect the costs of the new compression and refuelling stations.

Table 3 presents some of the technology costs (the most important to the analysis) used in the scenarios:

Table 2
Share and type of all road vehicles used in the biomethane and electromethane transport scenarios.

Propulsion type	Share	Propulsion type	Share
Cars and vans		**Trucks**	
Battery Electric	90%	Battery Electric	5%
ICE Methanol Hybrid	5%	ICE Biogas	51%
ICE Methanol Plug-in Hybrid	5%	ICE Biogas Hybrid	10%
Buses		ICE Methanol	24%
Battery Electric	15%	ICE Methanol Hybrid	10%
Methanol Fuel Cell	10%	**Vans**	
ICE Methanol Hybrid	20%	Battery Electric	35%
ICE Biogas	28%	ICE Methanol Hybrid	15%
ICE Methanol	27%	ICE Methanol Plug-in Hybrid	10%
		ICE Methanol	20%
		ICE Biogas	20%

3. Results

The best way to interpret the results is by understanding the consequences of replacing each of the fuels in the reference scenario by biogas, biomethane and electromethane, more than the sector it is replaced in, as seen Fig. 4. In the electricity, heat and industry scenarios, the new proposed fuels are replacing the same fuel but produced through different pathways and with different feedstock: biomass for biomass gasification.

Fig. 5 illustrates the gas demands and supply through the scenarios. The total gas demands vary between the scenarios, as the scenarios with the utilisation of the electromethane in transport have additional gas demand for this purpose, while in the other scenarios the transport demand is met by liquid bio-electrofuels. All the methane produced is sent to the gas grid, from which the consumers (electricity, industry and transport sectors) take the needed quantities. That means that the supply equals the demand in all cases, but the composition of the gas grid supply varies from scenario to scenario. In each instance, the gas produced through biogas, biogas purification or biogas methanation replaces the same share of gas as in the demand mix.

3.1. Wind and electrolysis capacities

As the gas production pathways change throughout the scenarios, so does the installed offshore wind and electrolysis capacities. Fig. 6 displays three main points. First, the wind and electrolysis capacities are lower when biogas or biomethane are used in industry and transport as they are replacing methane from biomass hydrogenation. Second, the lower electrolysis capacity for electromethane in transport occurs as the production of electromethane is less hydrogen intensive than the production of liquid electrofuels. Third, new electromethane demands create additional hydrogen demand to the current demands for hydrogen in the transport sector and industry, hence the increase in the capacities for wind and electrolysis in the power and heat scenarios.

Table 3
Main costs used in the analysis.

	Unit	Investment (M€/unit)	Lifetime (years)	O&M (% of investment)	References
Electricity production					
Onshore wind	MWe	0.93	30	3.4	[41]
Offshore wind	MWe	1.71	30	1.88	[41]
PV	MWe	0.56	40	132	[41]
Wave	MWe	1.6	30	4.9	[41]
Large CHP	MWe	0.8	25	3.25	[41]
Small CHP	MWe	0.85	25	1	[41]
Power plants	MWe	0.8	25	3.25	[41]
Fuel conversion					
Biogas plant	TWh/year	159.03	20	14	[42]
Biogas purification plant	MWfuel	0.25	15	2.5	[42]
Biogas methanation plant	MWfuel	0.2	25	4	[43]
Gasification plant	MWfuel	1.33	20	2.4	[42]
Gasification upgrade plant	MWfuel	0.68	20	1.7	[42]
Chemical synthesis	MWfuel	0.3	25	4	[43]
Jet fuel synthesis	MWfuel	0.37	25	4	[44]
Electrolysers	MWe	0.4	20	3	[42]
Hydrogen storage	GWh	7.6	25	2.5	[42]

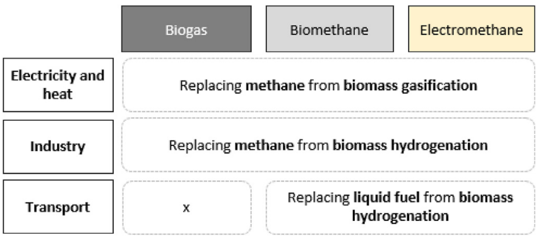

Fig. 4. The energy sectors and the fuels replaced.

There is a clear link between the increase in wind and electrolysis capacities, as the more electrolysis is in the system, the more wind is the system able to integrate. The scenarios with high wind and electrolysis capacity can be more flexible and produce less excess electricity than in cases with low wind and electricity capacity.

3.2. Primary energy supply and biomass consumption

As illustrated in Fig. 7, the scenarios where the electricity and heat production use biogas, biomethane or electromethane are the most efficient from the biomass consumption perspective, while the industry and transport scenarios, as well as the reference scenario, are the least efficient. All the scenarios bring savings in dry biomass consumption between 5% and 16% in comparison to the reference scenario. These savings connect directly with the fuels displaced by the biogas-derived fuels. In the case of biogas for power and heat, the saved dry biomass is larger than the inputted biogas feedstock. The lowest decrease in dry biomass consumption, of ~5%, takes place when the new fuels are displacing gasified biomass with electrolytic hydrogen. Using biomethane or electromethane in the transport sector offers a similar level of dry biomass savings as in the case of industry.

Overall results indicate that the electromethane scenarios have the highest primary energy supply due to the higher share of wind in the system. Even though the electromethane scenarios use lower amounts of biogas feedstock due to hydrogen addition, in the overall energy system picture, these do not use significantly less dry

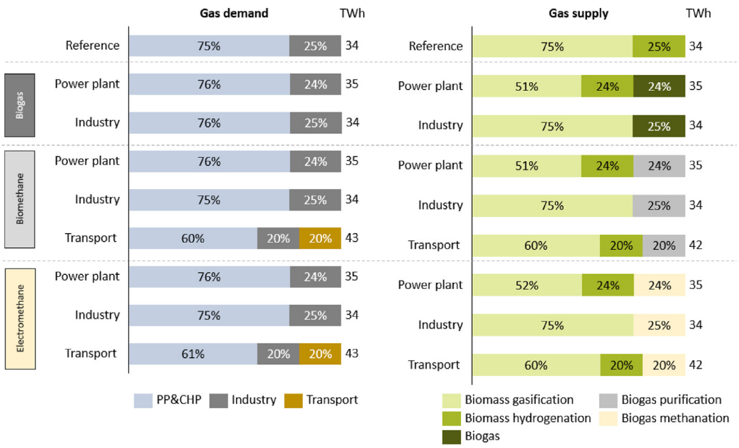

Fig. 5. Gas demands and gas supply in different scenarios.

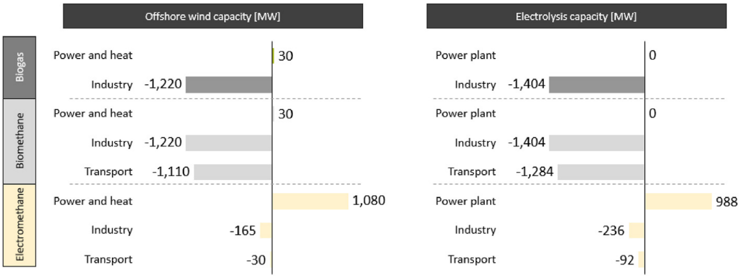

Fig. 6. Marginal difference in installed wind and electrolysis capacity in comparison with the reference system (vertical black line).

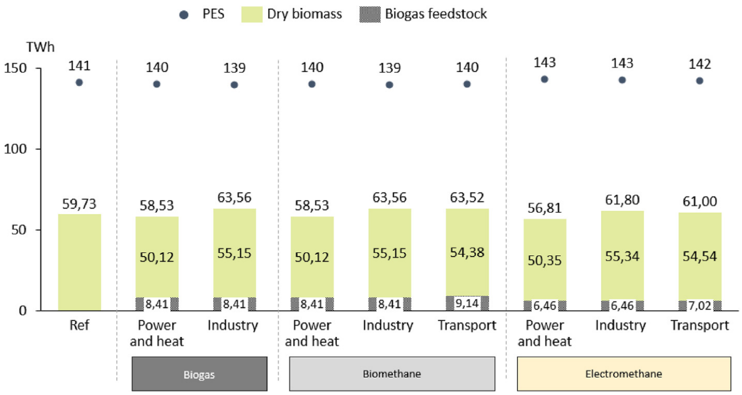

Fig. 7. Primary energy supply for different scenarios including dry biomass and biogas supply.

biomass than the biogas and biomethane scenarios. The energy system effects explain this result, where even if biogas feedstock is used more efficiently in the methanation unit, dry biomass is used in other parts of the energy system to fulfil other demands. Even though the total biomass consumption is higher in the biogas and biomethane scenarios, the overall primary energy supply is reduced compared to the electromethane scenarios due to the lower wind power capacity needed in the system.

As the biomass is going to be a very scarce resource in the future, the reduction of dry biomass consumption in the system is one of the main factors when determining which technology choices are better than other from the system perspective.

3.3. *Energy system cost comparison*

The eight scenarios with four different biogas feedstock cost levels include the handling costs. The results are presented as a marginal cost difference from the reference scenario that has no biogas utilised in the system. It is to be noted that in reality only part of the gas demand in the industry can be substituted with biogas; therefore this specific scenario is not necessarily fully representative, but it was used to illustrate the utilisation costs.

Fig. 8 illustrates the marginal cost difference of different scenarios to the reference scenario with a fixed biomass price of 6 €/GJ. A colour gradient visually separates the results from low cost (green) to high costs (red), where green indicates significant savings compared to the reference scenario while the red gradient shows a cost increase. As all the scenarios with different feedstock prices are related to the reference scenario, the colour gradient applies across all results.

The energy system costs show that using biogas for power generation offers more savings than using biomethane or electromethane. It is an effect of the costs, as biogas has considerably lower production costs than methane produced through biomass gasification and purification. It indicates that the utilisation of biogas should be prioritised in power and heat production, especially if the manure prices are low. Similar, in the case of industry, utilisation of biogas offers more savings than using biomethane or electromethane, but one must make a clear distinction that biogas cannot replace all methane demands in the industry. If looking across the fuels, prioritising both biogas and biomethane in the industry offers the highest savings for the overall system.

Once purified, biomethane shows reduced energy system costs when utilised in the transport sector. In the case of ‘free’ biogas feedstock, where manure cost is either subsidised or covered by the agricultural sector, instead of the energy sector, using biomethane for the transport sector achieves the highest cost savings compared to using electromethane. It also shows that it is slightly cheaper to use the biomethane for the industry than using biogas for power plants.

However, by increasing the biomass price to 8 €/GJ, the results show a somewhat different trend, as displayed in Fig. 9. By zooming into the use of biogas for power and heat generation or industrial purposes, the price difference becomes minor, though still with slightly higher savings in case of industrial application. The same trend is visible in case of biomethane for all three purposes. It is still

Marginal system cost difference [M€]		Biogas		Biomethane			Electromethane		
		Electricity and heat	Industry	Electricity and heat	Industry	Transport	Electricity and heat	Industry	Transport
Biogas feedstock prices [€/GJ]	0	-133	-174	-107	-147	-171	51	8	-20
	4.5	3	-38	29	-12	-33	155	112	87
	5.2	24	-16	50	10	-11	171	128	104
	5.9	46	5	72	31	11	188	145	121
Displacing		Gasified biomass	Gasified biomass + H_2	Gasified biomass	Gasified biomass + H_2	Liquid bio-electrofuels	Gasified biomass	Gasified biomass + H_2	Liquid bio-electrofuels

Low – High

Fig. 8. The marginal cost difference to the reference scenario for utilisation of biogas in different parts of the energy system with different levels of manure costs with fixed biomass price of 6 €/GJ.

Marginal system cost difference [M€]		Biogas		Biomethane			Electromethane		
		Electricity and heat	Industry	Electricity and heat	Industry	Transport	Electricity and heat	Industry	Transport
Biogas feedstock prices [€/GJ]	0	-202	-207	-176	-180	-209	-17	-24	-56
	4.5	-66	-71	-40	-45	-71	87	80	50
	5.2	-45	-49	-19	-23	-49	104	97	67
	5.9	-23	-28	3	-2	-26	120	114	84
Displacing		Gasified biomass	Gasified biomass + H_2	Gasified biomass	Gasified biomass + H_2	Liquid bio-electrofuels	Gasified biomass	Gasified biomass + H_2	Liquid bio-electrofuels

Low – High

Fig. 9. The marginal cost difference to the reference scenario for utilisation of biogas in different parts of the energy system with different levels of manure costs with fixed biomass price of 8 €/GJ.

clear that displacing the more expensive liquid fuels for the transport sector results in the highest savings if using biomethane in comparison to the other energy sectors. It is also visible that in case of 'free' biogas feedstock, it is not anymore cheaper to use biomethane in the industry than biogas for power and heat generation. It also shows, with minor differences, that utilising biomethane in the transport sector brings a similar reduction as using biogas in their respective sectors.

The increase in biomass price makes the choice of prioritisation of different forms of biogas more complicated, though still with a similar overall trend. Biogas matches better with electricity and heat generation, a result which also aligns with the biomass consumption of these scenarios in comparison to others as illustrated before in Fig. 7. Once purifying biogas to biomethane, transport sector shows the highest savings, but these are similar to the biogas scenarios.

The difference between the costs in some of the cases is almost negligible, making it difficult to conclude the preferred applications from a cost perspective. If dry biomass consumption is the primary consideration factor, then biogas should be the first choice for power and heat generation.

3.4. Fuel cost comparison

A fuel cost comparison can provide a different dimension to the choice of fuels in energy sectors. The fuel costs are based exclusively on the investment costs in the production chain of fuels, including wind and electrolysis investments for e-fuels. Fig. 10 illustrates the costs of biogas, biomethane and electromethane on four different levels of biogas feedstock price ranging from 0 to 5.9 €/GJ.

It is clear from the fuel price comparison that the cost increases gradually from biogas to electromethane. Cost of biogas for power and heat or industry is the cheapest in comparison to the other fuels and uses. Using biomethane in the transport sector is 8% more expensive than using it for power or industrial purposes, and this difference increases to 11% with the higher feedstock price. This cost increase is due to the additional compression costs needed for obtaining the fuel for the transport sector.

As expected, electromethane costs are the highest. With the highest feedstock cost, the electromethane costs increase by 33% in comparison to the ‘free’ feedstock scenarios. It makes electromethane more sensitive to feedstock prices compared to the other two fuels, even without considering a variation in the electricity prices. This result is also visible from the energy system analysis results. It should be noted that the increase in manure costs slightly reduces the price difference between biogas, biomethane and electromethane. When referring to the cost of fuels in power, heat and industry, electromethane has almost 50% higher costs in relation to biogas and 36% higher costs in comparison to biomethane in the case of free feedstock. However, when the feedstock price increases, the cost difference of electromethane reduces to 20% in comparison to biogas and 13% in comparison to biomethane.

When compared to the prices of the fuels in the reference scenarios, substituted with the biogas-derived fuels, results show that the new fuels can have a lower cost than the reference scenario equivalents only if biogas feedstock is cost-free. When the energy sector has to pay for it, then the cost of biogas, biomethane and electromethane is either on cost parity with the fuels they replace or significantly more expensive.

Fig. 11 illustrates the cost distribution for biogas, biomethane and electromethane. The cost of biogas consists only of the biogas plant costs, while in the case of biomethane between 8 and 9% of the costs is the biogas purification part. Electromethane for transport use has more complex cost structure, including biogas plant costs (47%), methanation costs (4%), costs for electrolysis (10%), offshore wind capacity (29%) and gas compression (10%), corresponding to the electricity demand for hydrogen production. The costs illustrated below are without biogas feedstock costs.

Additional sensitivity analysis was conducted to identify the fuel cost changes for the electromethane by altering several variables (Fig. 12). The reference cost structure represents 2050 costs for all the indicated technologies and is using offshore wind for hydrogen production. Results show that if onshore wind replaces offshore wind, then a price reduction of 15% can be achieved. However, if the electrolysis does not achieve the cost reductions expected and keeps a higher cost level (considering 2030 cost level), then the fuel cost level reduces by only 10%. Combined with offshore wind, then the fuel cost increases by 10% compared to the reference fuel cost. If all the costs remain unchanged from the 2020 levels, then electromethane costs are 82% higher. Table 4 lists the different cost levels, together with the cost of natural gas in Denmark for 2018 [45].

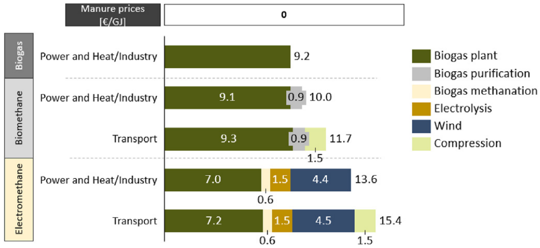

Fig. 11. Fuel cost and distribution shares for biogas, biomethane and electromethane without biogas feedstock/transportation expenses.

4. Discussion

Following the results of the energy system analysis and the fuel cost analysis, the use of biogas and biomethane present a better

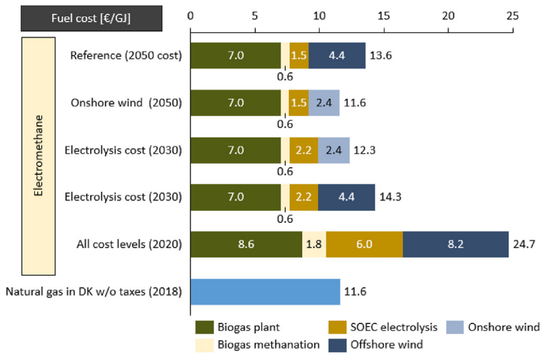

Fig. 12. Fuel cost sensitivity analysis with different cost parameter variations. The costs do not include the biogas feedstock, hydrogen storage or compression costs.

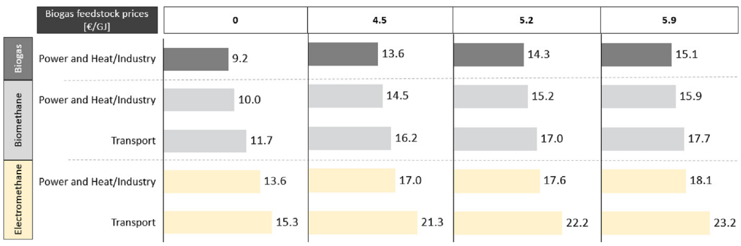

Fig. 10. Fuel prices in €/GJ with different manure cost levels and utilisation in different sectors for biogas, biomethane and electromethane. The cost does not include hydrogen storage.

Table 4
Cost levels for sensitivity analysis. Based on [16].

	Unit	2020	2030	2050
SOEC	M€/MW	2.2	0.6	0.4
Biogas methanation	M€/MW	0.6	0.3	0.2
Biogas plant	M€/TWh	195.64	176.19	159.03
Wind offshore	M€/MW	2.3	1.99	1.71
Wind onshore	M€/MW	0.99	0.91	0.93

economy and higher efficiency when compared to electromethane. A synthesis of the results is then necessary to understand the implication of each fuel choices. This synthesis is structured using the utilisation overview matrix in Fig. 2.

If biogas is the preferred end-fuel in any of the analysed sectors, then this has the benefit of the lowest production costs, due to the low number of technologies needed to produce it. However, being an impure gas, it has limited end-use applications. Electricity and heat production bring a good match for it from a cost and biomass consumption perspective, making it a suitable fuel in times when variable renewable energy cannot supply the heat and electricity demands. The utilisation of biogas in the industry has similar benefits, especially if biogas is to replace the same fuel as in case of power plants and CHP. However, the application to the industry will likely be limited as in the future the quality of the gaseous fuels demands may be higher, making biogas not suitable for this application. Regardless of the sector biogas is used in, one must keep in mind the logistics and costs of transporting the biogas to the end destination. In the future, biogas plans may be placed in the proximity of power and heat units or industrial sites so that local biogas distribution grids could be a solution. Due to this, biogas is suitable to be used locally, consistent with the results obtained by Hakawati et al. [32] and may allow for centralisation of biogas production, a measure that can reduce the cost of biogas production [21]. However, consideration should be put in the design of such biogas grids, as the biogas plants may be limited by the amount of biogas they can send to the local grid, primarily when the end-users operate on a flexible basis and the biogas plant operates continuously in which situation biogas storage may be needed.

If biomethane is the preferred end fuel, this has two main advantages compared to biogas - it is compatible with more applications and can use existing gas grids (if in place) for transporting it for longer distances, as also found by Hakawati et al. [32]. Current results indicate that biomethane application brings similar cost reductions across all energy sectors, especially in the scenarios with increased dry biomass prices. Among the sectors analysed, transport seems to achieve more cost savings, which occurs as biomethane replaces the more expensive production of liquid bio-electrofuels that require hydrogen for fuel generation. Biomethane is the transport sector could also be a cost-effective transition enabler if it can be used in dual-fuel vehicles as found by Hagos and Ahlgren [24]. However, the scenario limitations influence the results in this analysis by the fact that biomethane is replacing ~15% of the liquid CO_2-electrofuels, which are significantly more expensive than liquid bio-electrofuels. This limitation reduces the additional cost advantage of biomethane in transport compared to industry or electricity and heat production sectors which is in line with the findings from Jensen et al. [25], which assign renewable gases, mainly biomethane, with a key role in decarbonising electricity and district heating. Biomethane has a high potential for reductions across all scenarios, but with higher cost savings if it replaces a hydrogenated fuel. The future energy system will need CO_2 sources either in the form of CO_2 sinks or in the form of liquid electrofuels. When upgrading to biomethane, biogas is a CO_2 source, and this creates a gas easily transportable to power plants and industry.

If electromethane were to represent the fuel choice, then in all cost variations the end-use should only take place in the transport sector, where electromethane would be replacing similarly priced liquid electrofuels as methanol or DME. Even so, the difference between the electromethane and the liquid electrofuels is marginal to inexistent, and can strictly only exist if the agricultural sector pays for the biogas feedstock. Electromethane shares the same benefit as biomethane as it is suitable to be transported over longer distances using existing gas grids, but it presents unfeasibly high costs compared to biogas and biomethane if used in power and heat production and industry sectors simply because it is replacing a cheaper fuel that does not require electrolysis in the production process. As demonstrated by Nielsen and Skov [46], the potential of electromethane is limited by the investment cost in production plants and gas grids, even though electrolysis has the potential to provide additional balancing resources, however negligible in 100% renewable energy systems as the ones analysed here that already have large capacities of electrolysis.

If taken by sector, the power and heat sector results indicate that biogas is the preferred end-fuel, as it reduces both the dry biomass consumption and cost. Previous work [47] has demonstrated that using gaseous fuels in power and heat production presents more benefits than burning biomass directly, both from the cost and biomass savings perspective as well as for the system flexibility improvements. Biomethane can be a second preferred fuel if the electricity and heat production plants already have a gas grid connection or if biogas cannot prove as a suitable solution in the first place. Existing gas engines or gas turbines can use biomethane, but in the new heat and electricity developments, biogas should be the preferred fuel due to the high efficiency and lower production costs, as also found by Hakawati et al. [32].

In the industry sector, the recommendations are interchangeable with the ones from the power and heat sector if replacing the same type of fuel. The argument of using biogas in the industry grows higher if the cost of biomass is on the upper level while at the same time, it proves more resilient to increased biogas feedstock prices. As in the case of power and heat, biomethane should be preferred after biogas, if that is a requirement in the industrial processes.

In the transport sector, the only two gaseous fuel choices are biomethane and electromethane. Results show significant energy system cost savings if biomethane replaces the most expensive liquid fuels, even by accounting for higher vehicle costs and compressed gas-fuelling stations, which is a fair outcome. However, the cost reductions connect to the replacement of 20% of the CO_2-based electrofuels, otherwise strictly compared to bio-electrofuels the savings for compressed gas vehicles would be significantly lower. Even so, one must be careful in recommending biomethane as the preferred solution for the transport sector, as it may be more impractical than using liquid fuels. Von Rosenstiel et al. [48] investigated in their article the problems with gas vehicle implementation in Germany, where the strong correlation between the development of the infrastructure and willingness to invest in new technology has been hindering the implementation. Authors indicate six reasons for market failure, externalities including fuel price regulation, coordination of vehicle manufacturers and infrastructure development, lack of competition, imperfect information, bounded rationality and principle-agent problems. Moreover, electrification may take an even larger share of the transport demands, even for heavy-duty transport [49,50], in which case battery electric vehicles should be prioritised in front of any electrofuels especially if considering air pollution too. In the case of electromethane, there is practically no benefit in the transport sector, at least from a socio-economic perspective, since most liquid electrofuels have a lower cost.

The price of biogas feedstock is naturally a significant influencer of the fuel prices for any biogas based fuel type, making it debatable who ought to pay for the resources needed to produce biogas, this being mainly manure in the Danish case. Lastly, the conversion to organic farming may reduce significantly manure production, as well as a potential decrease in the demand for meat products due to changes in diet, which calls for a stronger collaboration between biogas producers and local farmers that need to maximise the synergies for both parties.

Overall, it is important to consider the arguments and incentives on why to use biogas for energy purposes. In their new report, Dubgaard and Ståhl [51] point out that production of biogas is a socially more expensive alternative for mitigation of CO_2 emissions in the agriculture sector among the analysed measures. However, these results do not show overall cost-effectiveness, as they are limited to the agriculture sector only.

5. Conclusion

Denmark has the highest share of biogas production among the European countries, and this share is projected to increase in the next decades. This study presents an overview of the role of biogas in Denmark in the year 2050 within the context of a 100% renewable energy system. By using an hour-by-hour energy system analysis, we illustrate how and where biogas resources should be used to achieve the highest efficiency and lowest energy system costs.

The results indicate that biogas should be used with the lowest amount of processing, as raw biogas for electricity production and district heat generation when possible. The reduced dry biomass consumption and reduced energy system costs endorse these results when compared to an energy system with no biogas. In cases where biogas is not suitable, biomethane can be used for the power, heat and industry sectors with similar results if it replaces a more expensive fuel and with the additional benefit of CO_2 sinks. Biomethane is also an option for commercial vehicles, buses and some of the heavy-duty transport with relatively low costs, but here it will be in direct competition with battery electric vehicles, which also require entirely new infrastructure, but are more efficient than any combustion engine. Moreover, stationary applications may prove a preferred solution from an air pollution perspective compared to using biomethane or electromethane due to due to less complicated emissions control. Electromethane does not show economic feasibility from a societal perspective when cheaper solutions are available, but its economics might change if further value streams are monetised, such as waste heat, oxygen from electrolysis and CO_2 storage. Moreover, electricity prices influenced by variable electricity production expose electromethane to significant cost variations, which will further influence its economics.

Declaration of competing interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

CRediT authorship contribution statement

Andrei David Korberg: Formal analysis, Software, Investigation, Resources, Data curation, Writing - original draft, Writing - review & editing, Project administration. **Iva Ridjan Skov:** Conceptualization, Validation, Resources, Writing - original draft, Visualization, Supervision. **Brian Vad Mathiesen:** Conceptualization, Methodology, Validation, Supervision, Funding acquisition.

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6.2 STUDY 2 - THE ROLE OF BIOMASS GASIFICATION IN LOW-CARBON ENERGY AND TRANSPORT SYSTEMS

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The role of biomass gasification in low-carbon energy and transport systems

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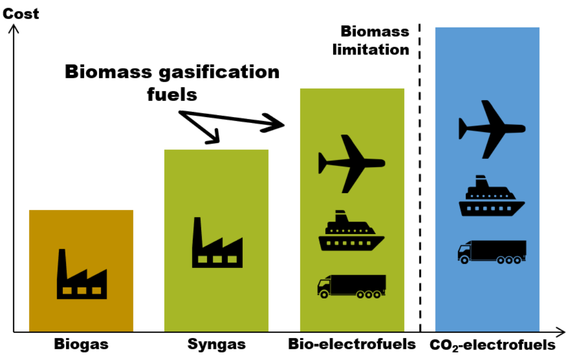
Highlights

- Biomass gasification is a key technology in all future renewable energy systems
- Biomass gasification-based bio-electrofuels have low costs compared to alternatives
- Methanol electrofuel production in general shows low resource consumption and costs
- CO2-electrofuels can complement bio-electrofuels depending on resource limitations
- Syngas from gasification can supplement biogas

Abstract

The design of future energy systems requires the efficient use of all available renewable resources. Biomass can complement variable renewable energy sources by ensuring energy system flexibility and providing a reliable feedstock to produce renewable fuels. We identify biomass gasification suitable to utilise the limited biomass resources efficiently. In this study, we inquire about its role in a 100% renewable energy system for Denmark and a net-zero energy system for Europe in the year 2050 using hourly energy system analysis. The results indicate bio-electrofuels, produced from biomass gasification and electricity, to enhance the utilisation of wind and electrolysis and reduce the energy system costs and fuels costs compared to CO_2-electrofuels from carbon capture and utilisation. Despite the extensive biomass use, overall biomass consumption would be higher without biomass gasification. The production of electromethanol shows low biomass consumption and costs, while Fischer-Tropsch electrofuels may be an alternative for aviation. Syngas from biomass gasification can supplement biogas in stationary applications as power plants, district heat or industry, but future energy systems must meet a balance between producing transport fuels and syngas for stationary units. CO_2-electrofuels are found complementary to bio-electrofuels depending on biomass availability and remaining non-fossil CO2 emitters.



Keywords: biomass gasification; electrofuels; methanol; syngas for power generation

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Abbreviations: CCS – carbon capture and storage; CCU – carbon capture and utilisation; CHP – combined heat and power; DME – dimethyl ether; FT - Fischer-Tropsch; GHG – greenhouse gas; GTL – gas-to-liquids; LMG – liquefied methane gas; POX – partial oxidation; SMR – steam methane reforming; VRES – variable renewable energy sources.

1. Introduction

Reducing and eliminating GHG (greenhouse gas) emissions requires technical and societal transformations. Two of the largest CO_2 emitters in Europe are energy production and transport [1]. Replacing power generation capacity with variable renewable electricity sources (VRES) can drastically reduce the emissions in this sector. However, a certain level of flexible power plant production will remain necessary to produce electricity when VRES cannot deliver the demand [2,3]. In the transport sector, direct and battery electrification can cover large parts of the demand, but that still leaves heavy-duty and long-distance transport like trucks, coaches, deep-sea shipping and aviation in need of a high-density fuel. Biomass can represent a solution for both energy sectors, contributing to supplying the electricity demands and producing high-density fuels. However, biomass is a limited renewable resource and can only complement VRES for power production and electrification in transport. Mortensen et al. [4] clarify the necessity for deep electrification and hydrogen integration to mitigate excessive land use threat and remain within biomass constraints. However, Hannula & Reiner [5] consider that biomass can enable a gradual transition to sustainable transport compared to electrification. The authors call for a portfolio of technologies to appraise the potential of biomass-based fuels, although acknowledging the competition for this resource with the power and heating sectors.

Except for the direct use of biomass in combustion units to produce electricity, heat, or for industrial purposes, biomass requires processing into gaseous and liquid fuels. For the production of gaseous fuels, anaerobic digestion can convert wet biomass feedstocks as manure, organic or industrial waste into high-density fuels. Solid biomass as woodchips, forestry products or straw can be thermochemically processed in gasifiers, to produce syngas. Biomass gasification accepts a wide variety of inputs, including agricultural waste [6], biogas digestate [7] or even waste tires [8,9], but depending on the gasifier design and process, there are different requirements for the moisture content and size of the feedstock. Another thermochemical route is pyrolysis, a process that decomposes solid biomass at high temperatures in the absence of oxygen. Fast pyrolysis co-produces biochar, gas and a high oxygen content bio-oil with a low-calorific value that requires upgrading before converting to transport fuels [10,11]. Another thermochemical route, the hydrothermal liquefaction, is more permissive with the feedstock, with no moisture-level requirements since biomass breaks down in a water environment. This alternative route produces a low oxygen bio-oil that can be put through regular refining procedures to produce transport fuels, but the technology is still in its early development [12]. Biochemical routes can also process solid biomass through fermentation to ethanol, but this suffers from low yields and requires intensive feedstock pre-treatment [13]. Unlike the routes mentioned above, gasification is a flexible biomass conversion method on the output side. Syngas can be used directly in cogeneration units or converted efficiently to simple liquids or gases, like methanol or methane. It can also be upgraded with hydrogen from electrolysis to produce electrofuels, here named bio-electrofuels, which increases the production yields, an essential aspect in the context of biomass availability in future energy systems.

Previous research found biomass gasification a critical technology to break the biomass bottleneck and move from biofuels to bio-electrofuels [14,15]. At the same time, other authors [16] called for continued development and research in biomass gasification even before pursuing the end-fuels, since many of the components are shared, referring to producing methanol/DME (dimethyl ether) and methane. Ridjan et al. [17] found the production costs of bio-electrofuels starting from biomass gasification to have the lowest costs among the synthetic fuels, due to the simplicity of the process and high conversion rate. Lester et al. [18] also found that bio-electrofuels as methanol or drop-in liquids have better potential to eliminate fossil fuels from the transport sector due to low production costs and low biomass consumption compared to CO_2-electrofuels and biofuels.

Fewer studies focus on the potential of syngas from biomass gasification for other applications than the transport sector. Connolly et al. [19] mentions biogas and syngas as potential replacements for the remaining natural gas in the energy system to achieve a 100% renewable energy system for Ireland but clarifies that other solutions may exist, such as grid-scale battery storage. The same authors [20] suggest methane from biomass hydrogenation and CO_2 hydrogenation to replace natural gas in the context of 100% renewable energy system for Europe but acknowledge this would be an expensive solution. On the same note, Mathiesen et al. [16,21] also consider syngas from biomass gasification for balancing a 100% renewable energy system for Denmark, by also calculating that the existing Danish gas storages are sufficient for the energy systems in a context of security of supply.

The choice of fuel production pathways can have a considerable influence on the type and amount of biomass used in the energy system. Mortensen et al. [22] study the energy system integration aspects of biomass, investigating the potential of straw residues for ethanol or biogas production, finding that straw has more system benefits if used with biogas. The study limits the research at two biomass conversion technologies and does not compare the energy system effects of using straw for biomass gasification. However, Venturini et al. [23] found that straw is more valuable if gasified and subsequently converted to Fischer-Tropsch (FT) fuels than used for biogas purposes. On a plant level analysis, Butera et al. [24] demonstrate the high efficiency of producing methanol from straw, with better results than some state-of-the-art plants on wood gasification. Methanol is often proposed as a future fuel for road transport or shipping [14,25–27] or as an intermediate for the production of jet-fuels [28,29], but other jet-fuel pathways have received more attention, namely biofuels [30,31] or gas-to-liquid (GTL) pathways starting from biogas [32]. The production of jet-fuels and maritime shipping fuels may be the few transport sectors that will require large amounts of renewable liquid fuels in the scenario of extensive road transport electrification.

Despite the growing body of literature dealing with the variety of fuels in different transport sectors [31,33–41] and with full decarbonisation pathways [20,21,42–46], few of these studies include biomass gasification in their assessments [21,36,44–46]. Furthermore, to the knowledge of the authors, no studies inquire in detail the potential system effects of biomass gasification. We hypothesise that biomass gasification may have a more significant role in the design of future energy systems for both transport and stationary units. To verify our hypothesis, we use energy system analysis to identify the system effects of large-scale biomass gasification implementation. We consider both hydrogenated and non-hydrogenated pathways, and we include them in the assessment together with biogas and CO_2-electrofuels.

2 Methodology

A high temporal resolution and data granularity tool are required to capture the dynamics in highly renewable or net-zero energy systems. EnergyPLAN was the tool of choice to carry out this analysis due to its capacity to balance the entire energy system on an hourly basis while also enabling cross-sector integration, rather than simulating the transport sector separately. The tool allows for detailed electrofuel inputs and flexible hydrogen production and storage for using VRES based on hour-by-hour time series [47].

For this analysis, we use two alternative reference energy systems for Denmark and Europe for the year 2050. In the case of Denmark, we set up our reference starting from the IDA Energy Vision 2050 [21], a 100% renewable energy system that was further updated to reflect tool developments and knowledge improvements. The model is operated as a closed system, without transmission imports and exports, to maximise the interactions between energy sectors. We calibrated it with an excess electricity production of 10% of the domestic electricity demands and a gas grid balance of 0, meaning that gas demand matches gas production, an essential aspect of quantifying gaseous fuels. Transport, personal vehicles and rail are almost full electrified, while light-duty vehicles and busses have a lower electrification level. Methanol produced in equal shares through biomass hydrogenation and CO_2 hydrogenation supplies the remaining demands of heavy-duty, long-distance driving and shipping. Aviation uses jet fuel produced through methanol-to-jet fuel synthesis.

For the European model, we used the European Commission's low-carbon energy models for 2050 [48], converted to EnergyPLAN models as described in [49]. We use one of their most ambitious decarbonisation scenarios, the 1.5 TECH, further adapted for this analysis. Compared to the original conversion to EnergyPLAN in [49], we calibrated the model on similar boundaries as the model for Denmark. We set the excess electricity production to 10% of the household and service demands by decreasing all the VRES proportionally. The model operates as a closed system with the remaining power production (that is not hydro, nuclear or VRES) balanced by power plants using natural gas. All the remaining emissions are offset by carbon capture and storage (CCS). The personal transport, light-duty vehicles and rail are electrified in a proportion of 80-90%, while busses and heavy-duty vehicles use a mix of battery electrification, fuel cells, liquids and gaseous fuels. Shipping and aviation are assumed to use a mix of biofuels, electrofuels and some fossil fuels [48].

The reference scenarios differ in design and approach. The Danish model builds on the concept of Smart Energy Systems which entails that an energy system is 100% renewable, uses a sustainable level of bioenergy, makes use of the synergies between energy grids (electricity, thermal and gas) and energy storages and is affordable. Such a system has a high degree of flexibility, by using large-scale district heating systems with large heat pumps and combined heat and power (CHP) and flexible electrolysis combined with hydrogen storage for the efficient use of available VRES. The European model is an evolution of the traditional fossil-fuel energy system that still relies on these fuels but offsets the emissions through carbon capture and storage (CCS). Despite using large amounts of VRES, the 1.5 TECH model is less integrated and less energy-efficient, and unable to use the excess heat from industry and fuel production due to the low district heating levels. It also uses less flexible electrolysis capacities and less hydrogen storage. Compared to the Danish model, the European model is less detailed on the transport sector, providing an approximation of the mix of fuels without including any vehicle and transport infrastructure costs. Because of the differences between the two models, these prove suitable test-beds to understand if the choices of technologies and fuel production pathways influence the energy systems the same way. Table 1 shows an overview of the main parameters for the two models.

Table 1: Main parameters of the reference systems

	Unit	Denmark	Europe
Primary energy supply			
On-shore wind	TWh/year	16.20	1,800
Off-shore wind	TWh/year	53.88	1,810
PV	TWh/year	6.35	1,210
Wave	TWh/year	1.35	0
Biomass	TWh/year	64.52	2,470
Conversion capacities			
On-shore wind	MWe	5,000	640,000
Off-shore wind	MWe	11,610	380,000
PV	MWe	5,000	840,000
Wave	MWe	300	0
Large CHP	MWe	3,500	25,000
Small CHP	MWe	1,500	
Power plants	MWe	1,000	241,000
Electrolysis	MWe	8,790	413,000
Energy demands			
Domestic electricity	TWh/year	32.92	1,690
District heating	TWh/year	28.19	200
Individual heating	TWh/year	14.51	1,180
Industry	TWh/year	11.82	2,391
Transport demands			
Electrification	TWh/year	9.43	604
Liquid fuels (except aviation)	TWh/year	18.68	430
Gaseous fuels (incl. H_2)	TWh/year	0	636
Liquid fuels aviation	TWh/year	8.01	670

2.1 Alternative scenarios

In the alternative scenarios for Denmark and Europe, we built extreme scenarios where we replace the renewable fuel production pathways in the reference scenarios with production pathways that use solely biomass gasification and hydrogenation (bio-electrofuels) or solely CO_2 hydrogenation (CO_2-electrofuels). With this approach, we focus on liquid and gaseous hydrocarbons without altering the electricity demands for electric vehicles, nor the hydrogen demands for fuel cells in transport. The intention is to reflect systemic changes in the fuel production pathways rather than shifting all energy carriers in the transport sector for each model.

The end-fuels considered are methanol, Fischer-Tropsch liquids and methane, where each fuel replaces another transport fuel in the reference scenarios either through the bio-electrofuel pathway or through the CO_2-electrofuel pathway, as follows and as illustrated in *Figure 1*:

- Methanol for heavy-duty road and maritime transport, while aviation utilises jet fuel produced through the methanol-to-kerosene synthesis (HydroMeOH scenarios).

- Fischer-Tropsch liquids to produce diesel for heavy-duty road transport and shipping combined with jet fuel for aviation (HydroFT scenarios).
- Liquefied methane (LMG) as fuel for heavy-duty road transport and shipping, while aviation uses jet fuel produced through the gas-to-liquids process. Section 3 further describes each of these pathways (HydroGTL scenarios).

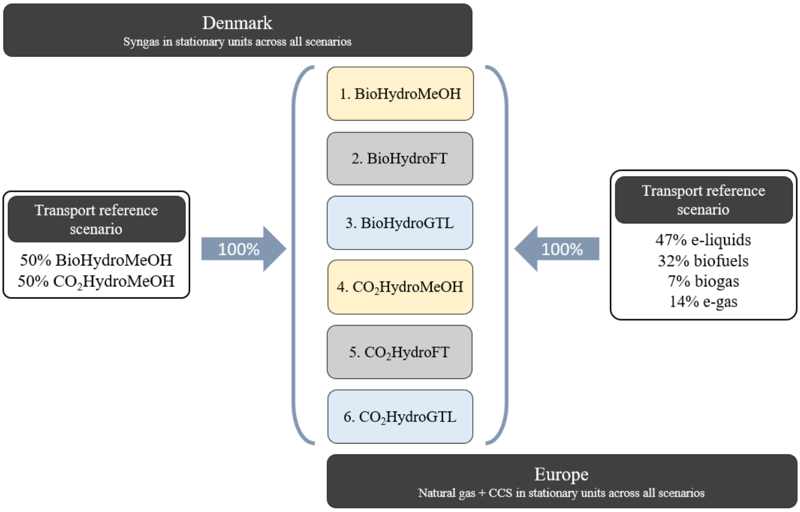

Figure 1: The six 'extreme' scenarios in the transport sector produced as bio-electrofuels or CO_2-electrofuels

The illustration in *Figure 1* also entails that all pathways refer to hydrogenated fuels since these allow for higher yields and energy system flexibility than non-hydrogenated pathways. Previous research [14,34,50] has demonstrated that hydrogenation is required to supply all the transport demands using renewable fuels while also achieving energy system flexibility and dealing with biomass availability and land use. Hannula et al. [15] demonstrated that the output of a methanol and methane plant could be increased by 2-3 times depending on the type of gasification used, for the same biomass input. For the FT synthesis, Hillestad et al. [51] found a similar increase in the fuel output, of 2.4 times compared to a plant without hydrogen enhancement.

As in the reference scenarios, the alternative scenarios keep the same energy system boundaries, meaning that excess electricity production remains 10% of the domestic/service demands balanced by adjusting upwards or downwards the off-shore wind capacity. We assume that on-shore wind and photovoltaic capacities remain fixed partly due to land constraints and as a method for simplifying the visualisation of the changes brought to the alternative scenarios. Hence the variations in electricity demands are illustrated through variations in off-shore wind capacity. The gas balance in the model for Denmark is kept at 0 (all gas demands in stationary units are supplied internally) throughout all scenarios by using syngas from biomass gasification, in a closed energy system (with no external electricity transmission). In the model for Europe, natural gas with CCS realises the balancing by keeping the net CO_2 emissions at 0.

3 Technology descriptions and costs

Biomass gasification is one of the leading biomass conversion technologies. Gasification is the intermediate step between pyrolysis and combustion that extracts the energy from biomass to a syngas (also known as producer gas) in an endothermic process. Depending on the end-use of the resulting gas, the oxidising agents can be air, oxygen or steam, which directly influences the contents of the syngas, which may be a mixture of nitrogen, hydrogen, carbon monoxide, carbon dioxide, methane, water and impurities as chlorine, sulphur, tar and dust. This mixture can be used directly in stationary electricity and district heat production units or industrial combustion units with minimal cleaning, which is also the assumption in our analysis. The type of gasifier considered for this purpose is a fixed bed design, but other designs exist, such as the circulating fluid bed and entrained flow gasifiers, more suitable for producing value-added liquid and gaseous fuels. The analysis considers such types of gasifiers to produce bio-electrofuels, combined with oxygen as an oxidising agent and extensive gas cleaning [12]. We assume overall biomass-to-syngas efficiency at 83% for this study [12].

The quality of the generated syngas depends mainly on the gasifier type, where fluid bed gasifiers require extra cleaning compared to entrained flow gasifiers to reduce or convert the content of hydrocarbons and tar compounds. The advantage with fluid bed gasifiers is the feedstock flexibility, where several publications have looked into the influence of different biomass blends for the production of quality syngas [52–54] as well as the output biochar quality, meaning that agricultural residues such as straw can be gasified and the nutrients returned to the agricultural soil [55,56]. Pre-treatment of biomass and post-treatment of syngas can be costly and energy-intensive steps [57], but downstream processes may enable synergies, e.g. heat for drying may be supplied by excess heat from the gas conversion process to either electricity or fuel. In our analysis, we consider a mix of biomass feedstock for gasification, including straw, woody products as well as energy crops and biogas digestate.

CO_2-electrofuels bypass the gasifier to use the CO_2 captured by point-source or direct-air capture units. Several concepts exist, but few tested on a large-scale. Among them, post-combustion and oxyfuel combustion technologies are the most mature. Post-combustion technology is meant to be adaptable and fit at the tail-pipe of combustion plants, allowing for retrofitting existing heat and power plants or industrial combustion processes [58]. On the downside, such applications may result in heat and power penalties, reducing the efficiencies. Oxyfuel combustion uses oxygen instead of air for combustion, resulting in nitrogen-free flue-gas consisting of water vapour and CO_2. It fits well with capturing CO_2 from cement plants, but it is not very suitable for retrofitting older units and also needs a source of oxygen [58]. For this analysis, we consider the post-combustion technology in the CO_2-electrofuel scenarios.

For the electrolysers, we use an energy efficiency (LHV basis) of 79% for the Danish model and 69% for the European model [12], while also assuming 5% compression losses for hydrogen storage. Hydrogen storage combined with few operation hours for electrolysers enables the flexible operation of the fuel plants since the gasification and fuel syntheses are assumed to operate continuously. Such an approach allows for a more accurate comparison between the production pathways, especially as FT has a low tolerance to load variations [12], but the methanol and methane syntheses may be operated flexibly [59]. Other flexibility measures may also be possible that do not include hydrogen storage, where instead the plant output is flexible, producing fuels or electricity, depending on the price of electricity and market demands [60,61], but these are not analysed here.

The methanol pathway entails the presence of a methanol synthesis reactor. The conversion losses limit the efficiency of the methanol synthesis reactions due to the exothermic nature of the methanol synthesis, and a small percentage of syngas will be purged from the synthesis loop. Therefore, in the pathway using biomass gasification and hydrogenation, we assumed a conversion energy efficiency of 80% [62], while for the pathway using CO_2 hydrogenation it may reach up to 88% based on the chemical reaction. Due to the more significant syngas loss when using CO_2 for synthesis compared to synthesis based on CO, we consider a value of 84%.

The available literature on producing aviation fuel through the methanol-to-jet fuel synthesis is scarce, where Schmidt et al. [28] analysed jet fuel production from methanol, comparing it with the FT pathway. The conversion to jet fuel includes several steps as the DME and olefin syntheses, oligomerisation and hydrotreating. All steps are already used in existing large refineries, but lack the technical demonstration of the complete pathway, even though analyses on the quality of the distillate fractions fulfil the specifications for 100% drop-in jet fuel [28]. Our analysis assumes a reaction efficiency from methanol to jet fuel of 74%, based on the results in [63].

The FT synthesis has been used for several decades already, often connected with fossil fuels, but there is less experience with biomass as feedstock. The synthesis requires a stoichiometric H_2/CO ratio slightly higher than two, which can be achieved with the water-gas-shift reaction or with the addition of hydrogen. The FT reactions are not particularly selective, but all plants would be calibrated to produce as much of the heaviest hydrocarbons as possible, which may also incur a trade-off between production rate and product selectivity. Future efficiencies may range between 70-75% from syngas to FT liquids [12,34], which is also close to the theoretical limit of the process, where the remaining output ends up as excess heat. Not all of the output is jet fuel or diesel, as a part of the fuel will end up as methane, ethanol, gasoline or naphtha. De Klerk [64] refers to an FT jet fuel yield of 60% of the total FT liquids, which is the value Mortensen et al. [32] used in their analysis. Our analysis assumes that the side products of such a refinery account for 30% of the FT products, expecting that the remaining 10% is not usable for the transport sector. We deduct the 30% side products from jet fuel production from the rest of the road transport demand to make the pathways comparable.

The third pathway in this analysis is methanation which is also an exothermic reaction where the output is methane and water. We use a conversion efficiency of 82% for biomass hydrogenation [65] and 83% for CO_2 hydrogenation, based on the chemical reaction. The resulting methane gas can be used directly in the gas grid and then compressed or liquefied. In this analysis, we assume the methane is liquefied for heavy-duty road transport and shipping, while for aviation, we assume the GTL process converts the methane to jet fuels. Most of the technology descriptions for the FT technology explained in the previous paragraph still apply, except the presence of partial oxidation (POX)/steam reforming (SMR) for converting methane to syngas. Depending on the scale of the GTL plant, Mortensen et al. [32] suggest an overall efficiency of 50-65% by the year 2030, including FT synthesis, depending on the choice of methane reforming. Methane reforming is an established technology, and we estimate it at 85-90% of methane input. Combined with the FT synthesis, the overall liquid output is estimated to 62%, the value used in this analysis. The product selectivity is assumed to be the same as in the previous pathway, meaning 60% jet fuel and 30% other transport fuels, the latter deducted from the road transport demands.

Table 2 presents the investment costs for the main technologies considered in this analysis:

Table 2: Main investment costs used in the analysis

	Unit	Investment (M€/unit)	Lifetime (years)	O&M (% of investment)	References
Electricity production					
On-shore wind	MWe	0.70	30	1.62	[66]
Off-shore wind	MWe	1.78	30	1.82	[66]
PV	MWe	0.49	40	1.59	[66]
Wave	MWe	1.60	30	4.90	[21]
Large CHP	MWe	0.80	25	3.25	[66]
Small CHP	MWe	1.10	25	2.36	[66]
Power plants	MWe	0.76	25	3.25	[66]
Fuel conversion					
Electrolysers	MWe	0.40-0.50	20	4.00	[12]
Hydrogen storage	GWh	17.00	30	1.00	[67]
Biogas plant	TWh/year	159.03	20	14.00	[12]
Biogas purification plant	MWfuel	0.25	15	2.50	[12]
Gasifier (power gen.)	MWfuel	1.33	20	3.00	[12]
Gasifier (fuel prod.)	MWfuel	1.57	20	3.00	[12]
Methanol synthesis	MWfuel	0.30	25	4.00	[34]
Methanol-to-kerosene	MWfuel	0.50	20	4.00	[68]
FT synthesis and upgrade	MWfuel	1.03	25	8.00	[12]
Methanation	MWfuel	0.20	25	4.00	[34]
Partial oxidation/Steam reforming	MWfuel	0.14	25	4.00	[69]
Post-combustion carbon capture	tCO2/year	300[1]	25	4.00	[58]

[1] Assuming a general cost for point source capture representative for a variety of sources.

4 Results

This study quantifies the energy system effects of utilising biomass gasification for both fuel production and power generation. Key results are on wind end electrolysis capacities, biomass and primary energy supply, including total energy system costs and fuel costs.

4.1 Wind and electrolysis capacities

Using any of the CO_2-electrofuels to supply the transport demands requires 50-60% more off-shore wind capacity than the bio-hydrogenation pathways in the Danish models and up to 60-75% for the European models, as illustrated in *Figure*

2. Another observation relates to the type of fuels produced in the pathways, where among bio-electrofuels the off-shore wind capacities remain similar, so producing methanol, FT liquids or methane has roughly the same effect. The differences appear when producing CO_2-electrofuels, which require significantly more electricity to achieve the same effect. There are approximately 2000 MW, and respectively 100 GW difference in favour of CO_2HydroMeOH pathway compared to the most wind intensive pathway, the CO_2HydroCH4 for Denmark and Europe. The CO_2HydroFT finds itself in between the two.

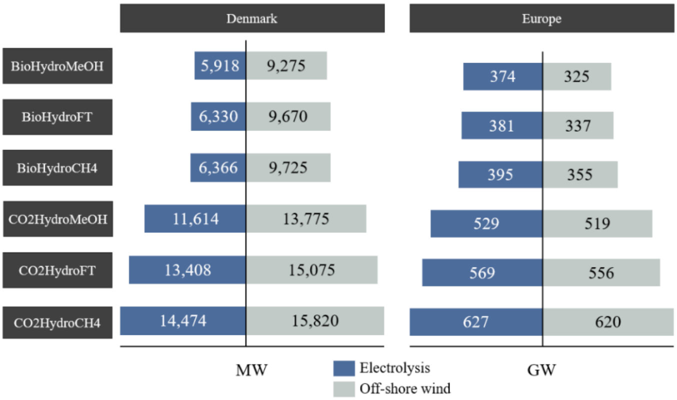

Figure 2: Installed capacities for wind and electrolysis in the Danish and European models

In regards to the electrolysis capacities, these follow the same trend as off-shore wind, wherein the case of Denmark the electrolysis capacities are 95-145% larger for CO_2-electrofuels than for bio-electrofuels. The differences are lower for the European scenario, but these still amount between 40-68% more capacity for CO_2-electrofuels. The modelling approach can explain this difference, where we use a flexible electrolysis capacity with 100% buffer capacity and large hydrogen storage of 7 days for the Danish model, compared to the European model where we only assume a smaller buffer on only 30% and only two days of hydrogen storage. Even so, the differences between the two types of electrofuel production are significant. As in the case of off-shore wind capacities, the electrolysis capacities for bio-electrofuels are similar, but differences occur between the end-fuels, with CO_2HydroCH4 requiring the largest electrolysis capacities, about 3000 MW more than the CO_2HydroMeOH pathway. As in the case of off-shore wind, the CO_2HydroFT finds itself between the other two pathways.

4.2 Biomass consumption

A boundary condition for the choice of technologies and production pathways is the amount of available biomass. In our analysis, we consider six extreme scenarios for Denmark and Europe, where we maximise the use of biomass gasification (Chapter 5 handles biomass availability). As such, in the case of Denmark, the total biomass consumption for producing bio-electrofuels is significantly higher than for CO_2-electrofuels by 30-45%, depending on the fuel production pathway. The BioHydroMeOH pathway has the lowest biomass consumption, with 18% higher biomass consumption for the FT pathway and 35% more biomass for the methane pathway. In regards to the biomass gasification for power generation, the results in *Figure 3* show approximately the same amount of gasified biomass for power generation across all three bio-electrofuels, indicating that the choice of fuel syntheses does not influence the operation of the power plants. However, it does influence the capacity of off-shore wind and electrolysis, as shown in *Figure 2*.

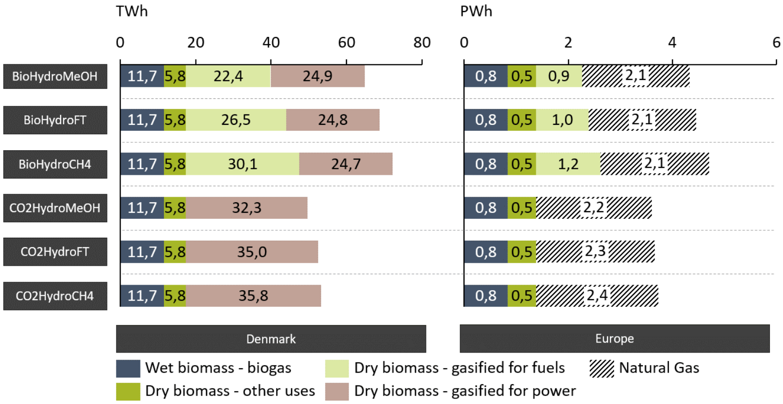

Figure 3: Biomass and natural gas consumption in the Danish and European models

In the case of the European model, the results are reasonably similar, the total biomass consumption for producing bio-electrofuels is 64-70% higher than in the case of CO_2-electrofuels, depending on the choice of pathway. As in the Danish model, the BioHydroMeOH pathway has the lowest biomass consumption among the bio-electrofuels, while the differences in natural gas consumption for the CO_2-electrofuel pathways are less evident, but these are still in the order of 100-200 TWh higher for FT and methane pathways.

In the future, there may be an interest to increase the ash output, a co-product of gasification that can be beneficial for soil fertility and carbon sequestration. We perform a sensitivity analysis that includes reducing the gasifier efficiencies from 83% to 70%, a low efficiency if the aim is to maximise the gas output. The analysis shows that the biomass consumption increases by 9-10 TWh in the BioHydroX scenarios, and by 6 TWh for the CO_2HydroX scenarios. In the European scenarios, where we only use gasification for fuel production, the increase in biomass consumption is 230 TWh. It may also be that not all gasifiers should produce biochar, in which case the gasifier efficiencies may be increased, with the current estimations suggesting 90% efficiency [12], reducing the amount of biomass they use.

4.3 Energy system costs

The choice of technologies and fuel production pathways influences the total cost of the energy system. A significantly larger capacity of wind and electrolysis is required to produce CO_2-electrofuels, although the production of these fuels does not use biomass directly, but can use biomass indirectly for power generation as in the case of the Danish models. An overview of the primary energy supply and energy system costs in *Figure 4* shows the increased overall fuel consumption for the CO_2 hydrogenation scenarios that account for approximately 30% more wind production to supply the same transport demands. The overall energy system costs reflect at 1-1.2 B€ higher for CO_2-electrofuels pathways due to the additional wind, electrolysis and hydrogen storage in the energy systems.

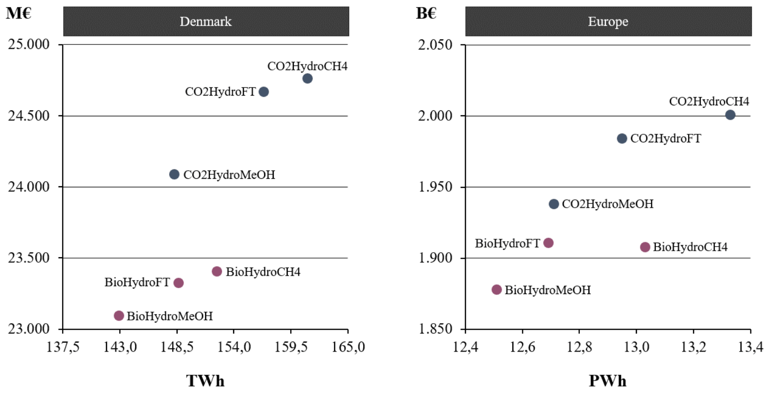

Figure 4: Primary energy supply and total energy system costs in the scenarios for Denmark

In the European models, we represent the transport sector without vehicle costs, which helps illustrate how the energy system costs differ without considering this aspect. The results in *Figure 4* illustrate that bio- and CO_2-electrofuels keep very similar cost differences between the pathways as in the Danish scenarios, illustrating that it is hardly the vehicle costs and their associated propulsion systems that influence the energy system costs. The differences between the two types of electrofuels are similar for the same end-fuels, varying between 60-90 B€ more for CO_2-electrofuels. Like in the Danish models, the main cost difference is represented by the increased capacities of wind, electrolysis and hydrogen storage, as illustrated in *Figure 2*, which accounts between 25-30% more electricity used in these scenarios than the bio-electrofuels.

The reduction in gasifier efficiency is also considered from an energy system cost perspective and compared to increasing the biomass feedstock price. The results show that reducing the gasifier efficiencies from 83% to 70% has a limited effect on the total energy system costs, but the biomass price increase to 10 €/GJ in the Danish model (from 6 €/GJ) has 3-4 times larger cost impact than using less efficient gasifiers. In the model for Europe, we apply a similar approach, by increasing the cost of biomass from 8 €/GJ to 12 €/GJ, which entails energy system cost increases between 21-26 B€/year, which is four times larger than using the low-efficiency gasifiers.

4.4 Fuel costs

The fuel cost analysis is another measure for quantifying the differences between the pathways and end-fuels, as illustrated in *Figure 5*. The price difference between bio-electrofuels and CO_2-electrofuels of 20-25% favours the former, due to the lower electricity consumption and reduced electrolysis and hydrogen storage capacity. For road transport and shipping, the lowest cost fuels are methanol and LMG, while FT diesel is significantly more expensive due to the higher resource consumption and expensive fuel synthesis. In the case of aviation fuels, jet fuel from methanol and FT jet show very similar costs, but at a considerable difference to the GTL jet fuel, primarily due to the numerous fuel conversions, which results in increased feedstock consumption.

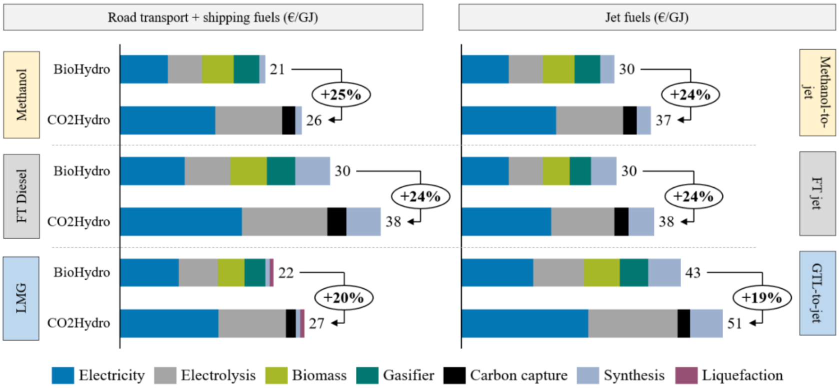

Figure 5: Fuel prices for the six pathways split between road transport + shipping on the left and aviation on the right. Electricity price is based on off-shore wind investments, while the electrolysis has an efficiency of 69% and includes a 30% overcapacity with 48h of hydrogen storage.

The prime determinator for the significant cost difference between bio-electrofuels and CO_2-electrofuels is the presence of biomass, which contains both the carbon and hydrogen in its composition, thus requiring less electrolytic hydrogen. Considering a different price for electricity or lower cost for electrolysis would not be revealing parameters for potential cost variations, as this would apply to both types of electrofuels. The sensitivity analysis takes methanol as an example. It reveals that doubling the price of biomass from 6 €/GJ to 12 €/GJ, reducing the gasifier efficiency to 70% (the minimum efficiency for today) or doubling its investment cost does not make this type of methanol more expensive than the cost of methanol obtained from carbon capture. Therefore, biomass price may be a more volatile parameter that can have a more extensive influence on the final price of the fuel, but the gasifier efficiency and investment cost have a more limited effect.

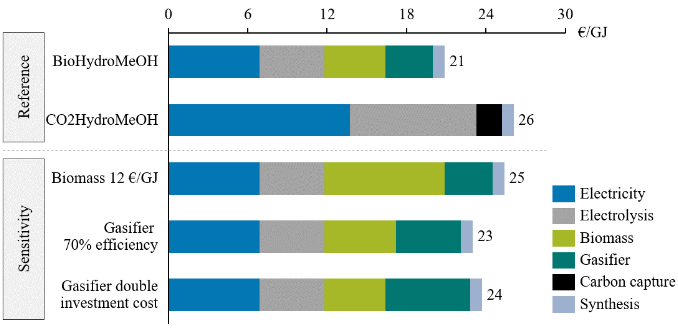

Figure 6: Sensitivity analysis of biomass and biomass conversion to methanol

Regarding the aviation fuels, the GTL pathway has received attention recently due to its potential to combine with biogas methanation [32], in the context where biogas has an increased role in the future energy system. Such a pathway would enable converting existing GTL plants using natural gas to produce future jet fuels. Our energy system and fuel cost analysis results revealed that the GTL pathway is the most expensive way of producing jet fuels, as shown in *Figure 5*. A reduction in the cost of electrolysis or electricity would not bring it in line with the other jet fuels because of its significantly higher hydrogen consumption than FT and methanol-to-jet pathways (~50% more hydrogen). Improving the conversion efficiencies of POX/SME and FT synthesis to theoretical maximums (i.e. 90% and 75%) would also not make this pathway sufficiently more cost-effective, as shown in *Figure 7*. The same figure demonstrates that even with free biogas feedstock, producing jet fuels is not economical. In our previous study [70], biogas shows better system effects when used in other energy sectors instead of transport, where dry biomass and liquid fuels have the lowest costs. Even so, a large gap still exists compared to the price of today's jet fuels by a magnitude of more than two.

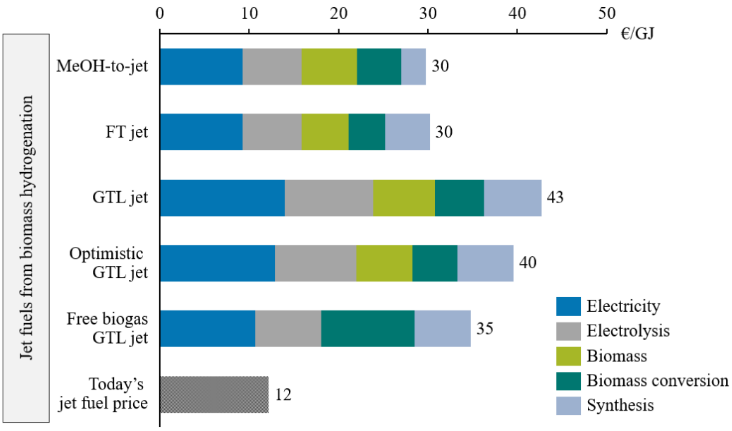

Figure 7: Cost sensitivity for jet fuels produced through the biomass hydrogenation pathways

There is also the aspect of the fuel prices for power generation. Our analysis for the Danish model found that approximately 24-36 TWh of biomass is converted to syngas for power generation, depending on the scenario (*Figure 3*), but this is not the only option. There is also the possibility of using natural gas offset by carbon capture, as in the European model, biogas, biomethane, electromethane or even ammonia power plants. Electrolytic fuels are a more expensive solution [70], and low-cost renewable fuels may be necessary for the task of power generation, which would make them comparable to other cost-efficient types of power generation, like wind or solar. *Figure 8* illustrates the levelized cost of electricity for these options, highlighting that syngas options are a more expensive solution than biogas and biomethane, which are closer to the production of electricity from natural gas.

Raw syngas or biogas as fuels for power generation would require dedicated grids for transporting the gas to the power generation units which would entail a higher cost for these options if the fuel production cannot occur in proximity of the plants. In the case of syngas, it also means less biomass consumption due to eliminating the upgrade (methanation) to grid quality, a process bound to energy losses. Therefore, the upgraded syngas would be comparable in quality with other renewable gases as biomethane from biogas, which means they can combine in a single gas grid. However, this would also entail a higher cost for producing electricity than off-shore wind and raw biogas, as illustrated in *Figure 8*.

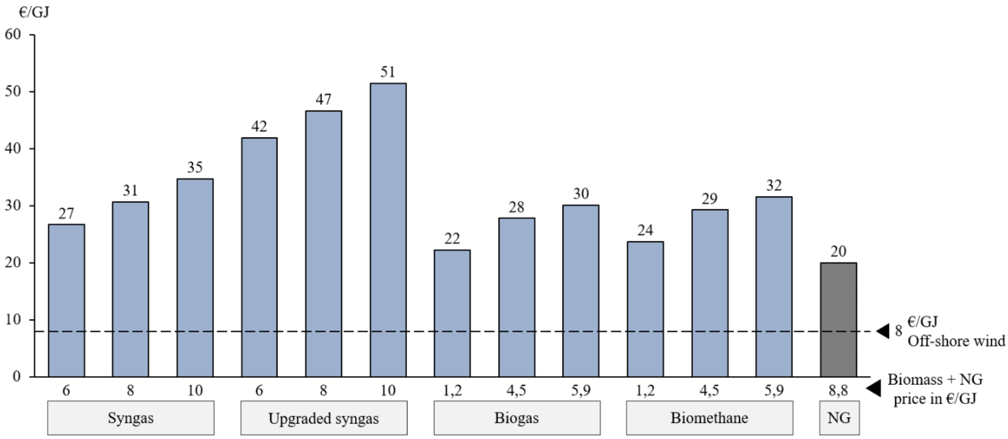

Figure 8: Levelized cost of electricity for a CCGT in extraction mode with 4000h of operation hours with different fuels options and prices, compared to the off-shore wind electricity price, all at 2050 cost and efficiency levels [66].

5 Discussion

The effects of utilising biomass gasification appear beneficial to the energy system costs, but the available biomass resources limit its use in parts of the energy system where there is the most need for it. *Figure 9* illustrates two projection of biomass resources for Denmark and Europe.

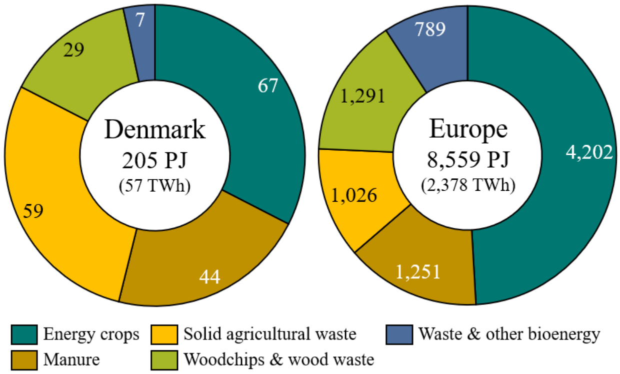

Figure 9: Estimated domestic biomass potentials in 2050, excluding algae and waste. Adapted from [71–73].

The results indicate that the BioHydroX scenarios for Denmark use 65-72 TWh biomass, which is more than the total available biomass in the country. In these extreme scenarios, biomass may be sufficient if gasified and hydrogenated for supplying the transport demands, but insufficient if also used for electricity production. For the European energy system, considering the energy and transport demands suggested by the European Commission in the 1.5 TECH scenario [48], biomass gasification may fit within the available biomass resources. However, such a system will still be dependent on large amounts of natural gas. The two models are not directly comparable in this sense, as Denmark is one of the five regions in Europe with the highest biomass potential [74], with around 30-35 GJ/capita [23]. In comparison, global non-food biomass potential ranges between 13 to 28 GJ/capita in 2050 [75] and Europe with 15 - 16.5 GJ/capita [73,74]. Similarly, the EU potential varies widely, ranging from 6.6 to 21.8 EJ/year in 2050, excluding imports [73]. Solving the challenge of biomass availability will require other solutions, particularly an increased level of electrification for all transport sectors. It should cover transport modes previously considered difficult to electrify, as heavy-duty transport [76,77] or some types of ships or planes. Grid-scale energy storage may be another possibility, but current research has identified such solutions expensive, that will still require a significant level of power plants in the energy system [16,48,78].

The CO_2HydroX scenarios for Denmark represent another alternative for dealing with the biomass limitation. These illustrate the case where sufficient biomass exists for gasification and power production purposes independent of the fuel production pathways. The scenarios assume that carbon sources exist and can be captured from industrial sources, power plants and CHPs. However, even if all units would use carbon capture, there will likely be insufficient renewable carbon to supply the fuel production processes that require 7-10 Mt/year in the case of Denmark. Moreover, one must consider that power plants operate flexibly for few hours over the year, creating a fundamental conflict, as carbon capture technologies have high investment costs and long lifetimes requiring a high number of operating hours to be economically feasible [79,80]. In the CO_2HydroX scenarios, cogeneration and power plants operate at no more than 1500-2500 full load hours/year in the Smart Energy System model for Denmark and 3000-4000 full load hours/year in the carbon-neutral model for Europe, which may be insufficient to deploy carbon capture, unless forcing the operation of power plants. This solution will result in VRES curtailment and increased fuel consumption, like in the model for Europe. An alternative is the use of carbon from industrial resources, cement production or biogas purification, but this may also be insufficient, particularly if industries switch to zero-emission fuels [81] or electricity. Other solutions may require direct air capture or ammonia production for some parts of the transport sector and power generation, but the cost of such an alternative would remain high, due to the large electricity consumption. Furthermore, the high toxicity of ammonia may be an issue when compared with the other fuel options considered in this study.

Therefore, a prioritisation of the available resources must be considered for both biomass-based and CO_2-based fuels, as both solutions present challenges. Connolly et al. [14] find biomass gasification to be a transition technology that may jump-start the production of electrofuels, at least until the price of electricity will be lower than the price of biomass. We find that biomass gasification may be more than a transition technology in the long-term, but one that should stay. Within the prospect of biomass sustainability, but often neglected in energy system analyses, is the issue of soil management. Along with the production of syngas, biochar (ash) results as a co-product, but to this date, it is not considered a valuable output. Efforts have been put so far on maximising the carbon conversion to syngas, but gasifiers can be adjusted to leave more carbon in the biochar. This is important as biochar contains stable carbon, more stable than the carbon in biomass, and it can be a method for restoring carbon balance in the soil while also acting as a method for carbon sequestration [55]. Our energy system analysis results find that using less efficient gasifiers that produce biochar is a small price to pay, and may ultimately ensure a more optimised influx of biomass as an effect of improved soil management.

Despite the differences between the two pathways, a mix between sustainable biomass consumption and CCU will likely be necessary for the future. Biomass gasification alone may not have the potential to supply both transport demands and gas production for stationary units as in power production. The option of using predominantly CO_2-electrofuels is significantly more expensive, requiring non-fossil CO_2 sources that may not be available, as well as a larger land area to accommodate the increased electricity demands [22,33].

Considering critical aspects of energy efficiency, biomass limitations and costs, we find that biomass gasification combined with methanol production as primary fuel should be prioritised for the transport sectors where electrification is difficult. CO_2-electrofuels may be an add-on technology that may make use of the remaining large carbon emitters to produce high value-added fuels, as for aviation. A balance between producing fuels for transport and syngas for mainly power production should be achieved, as the low-cost renewable fuel options for electricity generation are more limited than for the transport sector.

6 Conclusion

In this study, we analysed the potential role of biomass gasification in the context of two different energy system designs for Denmark and Europe in the year 2050. The results demonstrated that utilising biomass gasification for the production of bio-electrofuels in the transport sector can reduce the energy system costs and improve the overall energy efficiency compared to energy systems dominated by CO_2-electrofuels. Despite the high biomass consumption in the bio-electrofuel scenarios, the overall biomass consumption would be higher in energy systems without biomass gasification due to their lower efficiency. Among the electrofuels investigated, methanol shows the lowest resource consumption and costs, but FT fuels may be an alternative for aviation.

Therefore, we find syngas from biomass gasification to have significant potential in supplementing biogas in stationary applications for power production and heat or industrial demands. A careful balance should be achieved between supplying syngas for power production and syngas for fuel synthesis, in which case CO_2-electrofuels can complement bio-electrofuels in the transport sector.

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6.3 STUDY 3 - TECHNO-ECONOMIC ASSESSMENT OF ADVANCED FUELS AND PROPULSION SYSTEMS IN FUTURE FOSSIL-FREE SHIPS

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Techno-economic assessment of advanced fuels and propulsion systems in future fossil-free ships

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ABSTRACT

This paper analyses the potential of renewable fuels in different propulsion systems for the maritime sector that can replace fossil fuels by 2030. First, a fuel cost analysis is performed for a range of biofuels, bio-electrofuels, electrofuels plus liquid hydrogen and electricity in 18 fuel production pathways. Next, fuel production costs are combined with different utilisation rates, propulsion cost, on-board fuel storage cost and a cost for reduced cargo space to determine the total cost of ownership for four types of ships: large ferries, general cargo, bulk carriers and container vessels using internal combustion engines, fuel cells or battery-electric propulsion systems and travelling different distances.

In large ferries, the battery-electric propulsion is found at a lower cost than all fuel options except biofuels. For the other ship types, cheaper fuels (as biofuels) benefit internal combustion engines, while expensive fuels (as electrofuels) increase the competitiveness of fuel cells due to their higher efficiency. Similarly, low utilisation rates benefit internal combustion engines, while higher utilisation rates tend to support fuel cells. General cargo vessels have a similar total cost of ownership for both four-stroke internal combustion engines and fuel cells. Bulk carriers and container ships use two-stroke engines, with efficiencies closer to fuel cells, but the lowest-cost solution remains internal combustion engines, except when increasing the efficiency or reducing the investment cost of fuel cells. In almost all fuel-propulsion combinations, methanol is the lowest-cost fuel, but dimethyl ether and ammonia show only marginally higher costs.

1. Introduction

There is a need to significantly reduce GHG emissions in all sectors to limit human-induced climate change. Seaborne transport representing over 80% of total global trade by volumes [1] is no exception. It is dominated by fossil fuels, mainly HFO and MGO and contributes to 2–3% of global anthropogenic CO_2 emissions [2,3]. The IMO agreed to reduce the total amount of GHG emissions from shipping by 50% before 2050 and continue to phase out GHGs as soon as possible in this century [4]. The European Commission has expressed a long-term objective of 'zero-waste, zero-emission' maritime transport in the "EU Maritime Transport Strategy 2009–2018" [5] and states that CO_2 emissions from maritime transport in the European Union should be reduced by 40% by 2050 compared to 2005 levels in the white paper "Roadmap to a Single European Transport Area" [6].

Very low and eventually zero GHG emissions from shipping can be achieved with energy efficiency measures combined with a change to low or zero-carbon energy carriers. Possible energy efficiency measures include operational measures such as voyage optimisation and capacity utilisation, technical measures such as improvements in hull design and changes in power and propulsion systems [7]. There is a range of different marine fuel options with varying characteristics in terms of

Abbreviations: kWh, kilowatt-hour; kt, kiloton; GWh, Gigawatt hour; M€, million euros; MW, megawatt; t, tonne; TWh, terawatt hour; AEL, alkaline electrolyser; ASU, Air separation unit; BE, battery-electric; CO_2, carbon dioxide; DAC, direct air capture; DME, dimethyl ether; DWT, deadweight tonnage; FC, fuel cell; GHG, greenhouse gas; FT, Fischer-Tropsch; HFO, heavy fuel oil; HVO, hydrotreated vegetable oil; ICE, internal combustion engine; IMO, International Maritime Organisation; LBG, liquefied biogas; LH_2, liquefied hydrogen; LHV, lower heating value; LMG, liquefied methane gas; LNG, liquefied natural gas; LT/HT PEMFC, low-temperature/high-temperature proton exchange membrane fuel cell; MGO, marine gas oil; NH_3, ammonia; NOx, nitrogen oxides; PEMEL, proton exchange membrane electrolyser; PM, particulate matter; RWGS, reverse water-gas shift; SOEL, solid oxide electrolyser; SOFC, solid oxide fuel cell; TCO, total cost of ownership

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availability, cost, energy density, technical maturity and environmental impact [8–13]. Incremental reduction of harmful emissions is possible by changing to cleaner distillate fuels, LNG or fossil methanol, or exhaust abatement equipment such as scrubbers and selective catalytic reduction units [14]. Several projects analysed these fuels [9,10,15], but they have similar, or even increased, impact on climate change as conventional fossil fuels [16–18].

Energy carriers associated with low or zero GHG emissions during their life cycle include different types of biofuels, electrofuels and electricity produced from renewable energy sources such as biomass, solar, and wind energy. Like vegetable oil, butanol and LBG, biofuels are tested in several maritime demonstration projects [19–21], but they face challenges with availability, cost, and sustainability as all biofuels.

Electrofuels use electricity as the primary energy source to produce hydrogen [22], which can be used as a standalone end-fuel or combined with carbon or nitrogen. Carbon-based electrofuels can be produced from non-biogenic CO_2 and in combination with biogenic CO_2 sources to co-produce bio-electrofuels, by increasing the yield of biofuel production. Both types of electrofuels are relevant as they can be used in existing ships and utilise existing infrastructure, relevant for the transport sector due to the long lifetime and costly retrofits of ships. Ammonia is another electrofuel that uses nitrogen and has recently been put forward as a potential marine fuel [23–27] but requires more extensive studies to determine if it can be a suitable fuel for the maritime sector. There is a growing body of recent literature investigating the potential of electrofuels in the transport sector [28–39]. However, studies with an in-depth focus on electrofuels in shipping are relatively few [11,24,40,41].

Instead of using electrofuels, it is possible to use hydrogen directly in ICEs or FCs. Hydrogen in FCs is an attractive option for on-board ship power generations and can be integrated into all-electric vessels [42–44]. Due to its low volumetric density, hydrogen requires more extensive and more expensive storage systems, but some vessels use compressed hydrogen in FCs [45,46]. Liquefaction of hydrogen is more space-efficient but also a more energy-demanding, and to the authors' knowledge, there are no commercial ships in operation using liquified hydrogen. Furthermore, the interest in hybrid and fully BE propulsion on ships is increasing significantly for coastal and inland vessels [47,48] but also for vessels operating on fixed routes, e.g. road ferries. For longer distances fully BE propulsion on ships faces challenges with cost, size and weight of batteries [24,40,49,50].

There are many possible alternative marine fuels, and several scientific studies [8,24,35,40,51,52] and reports [10,13,25,50,53] investigated different possibilities. A limited number of scientific studies investigate multiple fuel options comprehensively from fuel production pathways to propulsion technologies. This study addresses this knowledge gap by assessing the costs of a range of renewable fuels and propulsion systems. A comparative techno-economic analysis of different fuels and propulsion systems is made, which have been put forward as potential solutions for ICE, using MGO as a reference to provide a deeper understanding of the choice of some fuels against others. The assessment is both quantitative and qualitative, where the technology constraints shape the economic analysis and vice-versa. It is targeted towards the year 2030 due to the reliability of the cost data and technology readiness level (more certain than for 2050), and because change needs to occur sooner than later, so the present study can be used as a tool in the ongoing debate of decarbonising the shipping sector.

2. Methodology

Three distinct parts split the analysis, as illustrated in Fig. 1. The first part determines the fuel cost based on different production pathways, including an infrastructure cost for fuel handling, storing and bunkering in ports. The second part of the analysis focuses on capital and operational expenditures for four representative categories of ships travelling three different annual distances and calculates the fuel consumption considering the compatible propulsion systems. Finally, part three of the analysis combines the fuel and ship analyses results to determine the TCO by including the costs for the on-board fuel storage and the cost for reduced cargo space, as illustrated in Eq. (1).

$$TCO = (Cost_{fuel} \times Consumption_{fuel} \times Utilisation_{rate}) + Cost_{propulsion} + Cost_{storage} + Cost_{reduced\ cargo\ space} \quad (1)$$

Capital costs are estimated for 2030, where available data allowed for such differentiation and expressed in 2019 euros (€) in real terms as we do not consider future inflation. The study uses a global discount rate of 3% per year for the annuity calculation in both the fuel production cost and propulsion systems, and the costs do not include taxes and fees or industrial profits. Microsoft Excel was the tool of choice for the analyses.

2.1. Fuels and production pathways

The fuels selected for this study are diesel, methanol, DME, LBG, LMG, HVO, ammonia, hydrogen and electricity, all judged technically feasible for the maritime sector. We consider these fuels as carbon-neutral, using non-fossil carbon capture as well as renewable electricity and biomass. They are categorised in four fuel production pathways: biofuels, bio-electrofuels, electrofuels, liquid hydrogen and electricity, resulting in a comparison of 18 fuels, as shown in Fig. 2. Diesel, methanol, DME, LMG and LBG can be produced by two to three path-

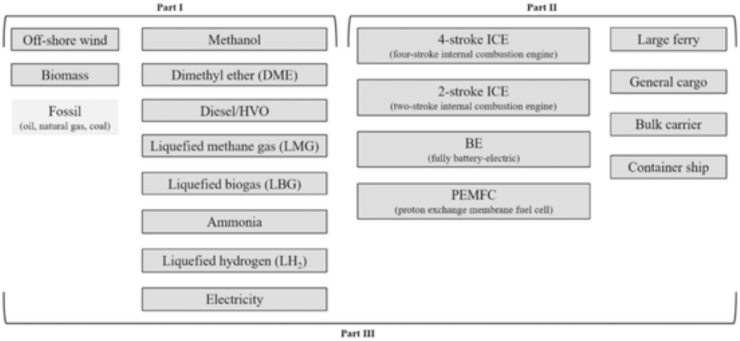


Fig. 1. Overview of investigated options. Fossil options are not assessed but included as a comparison.

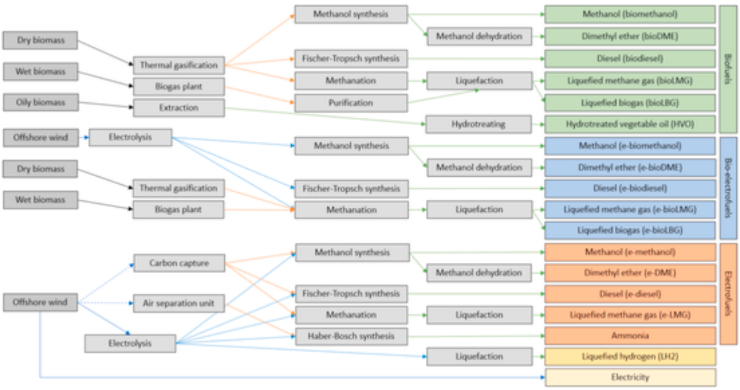


Fig. 2. Simplified overview of the fuel production pathways investigated. Only electrolysis is assumed to operate intermittently, while carbon capture or air separation unit uses grid electricity because of their constant operation requirement. Some of the fuel syntheses also require electricity while HVO requires some hydrogen (both accounted in the fuel cost calculation).

ways, which allows for an improved comparison between the resulting fuel prices.

To differentiate between the categories of fuels, these are named accordingly depending on the production pathway. For biofuels, where biomass is sole feedstock, the prefix "bio" is used. Bio-electrofuels are differentiated by the prefix "e-bio" due to the utilisation of the excess CO_2 in biomass through electrolytic hydrogenation. For electrofuels, the CO_2 is added from carbon capture and hydrogenated, giving the prefix "e–".

A significant cost component in the bio-electrofuel and electrofuel production is electricity. Due to the renewable nature of the fuels assessed in this paper, the investment cost of off-shore wind is chosen as a proxy for determining the electricity cost (33 €/MWh in the base case). A main off-shore development area in Europe is the North Sea, where, according to the Danish Energy Agency [54], a capacity factor of 53% and technical availability of 97% are found representative for the year 2030, which equals 4500 full load hours over a year. The same full load hours are reflected in the electrolyser operation.

There are three leading technologies for electrolysers: AEL, PEMEL and SOEL. This analysis uses the efficiencies provided by the Danish Energy Agency [55] for 2030: 66%, 62% and 79% respectively, in the LHV. Since there will probably be a mix of electrolysers used for this purpose by 2030, the analysis assumes a simple average efficiency for all electrolysis: 69%. Furthermore, due to the intermittent nature of renewable electricity production, short-term hydrogen storage is included. It is difficult to determine a specific storage size in the context of this analysis without using modelling tools, e.g. on plant or energy system level, but the authors assume using steel tank storage with a capacity that can supply the demand for 24 h together with a 30% buffer capacity to deal with peak production. For the compression of hydrogen, additional 5% losses of the output hydrogen are assumed.

Table 1 illustrates the cost data and efficiencies used for the fuel production technologies, while a detailed description of the fuel production pathways, process and efficiencies in the fuel analysis, can be found in Appendix A of Supplementary material.

Table 1
Cost data and conversion efficiencies in 2030 for the equipment used in the production pathways.

Technology	Investment	Unit	O&M[a]	Lifetime	Efficiency (LHV)	Source
Off-shore wind	1.93	M€/MW_e	2.5%[b]	30	53%[c]	[54]
Electrolysis	0.60[d]	M€/MW_e	4.0%	20	67%	[55]
Gasifier	1.56	M€/MW_{fuel}	2.3%	20	77%	[55]
Biogas plant	1.91	M€/MW_{fuel}	7.0%	20	N.A.	[55]
Carbon capture	400	€/tonne CO_2	4.0%	25	N.A.	[56]
ASU	181	€/tonne N_2	2.0%	20	N.A.	[57]
Ammonia synthesis	0.44	M€/MW_{fuel}	2.0%	20	87%[e]	[57]
Catalytic methanation	0.31	M€/MW_{fuel}	4.0%	25	77%	[58]
Chemical synthesis	0.52	M€/MW_{fuel}	4.0%	25	79%	[58]
FT synthesis	0.73	M€/MW_{FTfuel}	4.0%	25	73%	[58]
Methane liquefaction	0.50	M€/MW_{LMG}	5.0%[f]	30[g]	97%[g]	[59]
Hydrogen liquefaction	1.40	M€/MW_{LH2}	5.0%[f]	30[h]	75%[h]	[46]
Biogas upgrade	0.27	M€/MW_{fuel}	2.5%	15	100%	[55]
Hydrogen storage	38	M€/GWh	1.4%	30	90%	[60]
Diesel infra.	0.10[i]	M€/MW_{fuel}	2%	30	N.A.	[52]
Methanol infra.	0.2[i]	M€/MW_{fuel}	2%	30	N.A.	[52]
DME/ammonia infra.	0.4[i]	M€/MW_{fuel}	2%	30	N.A.	[52]
LMG/LBG infra.	1,6[i]	M€/MW_{fuel}	2%	30	N.A.	[52]
LH_2 infra.	2.3[i]	M€/MW_{fuel}	2%	30	N.A.	[52]

[a] Percentage of investment.
[b] Including fixed and variable O&M for the specified efficiency.
[c] Capacity factor.
[d] The average cost of the three most common electrolysis technologies.
[e] Calculated from the chemical formula (hydrogen to ammonia).
[f] Estimated based on [52].
[g] Calculated based on consumed electricity (0.03 $kWh_{el}/kWh_{LMG/LBG}$).
[h] Calculated based on consumed electricity (0.25 kWh_{el}/kWh_{LH2}).
[i] Including fuel storage, fuel handling and bunkering.

2.2. Ships and propulsion systems

The marine sector includes a multitude of ships of different sizes and engine capacities that fulfil a variety of roles and travel shorter or longer distances. We considered four types of ships: large ferries, general cargo, bulk carriers and container ships. Together with oil tankers, not included in this analysis, general cargo, bulk carriers, and container ships produce the most significant amounts of CO_2 emissions among all types of existing ships [3].

Using the third IMO GHG study [3], a case study ship was defined for each ship category based on the average mechanical output. Each ship is assigned with three utilisation rates, based on the average number of days at sea [3], and three voyage lengths. Each utilisation rate couples with its respective voyage length, the low utilisation rate with the short trip, median utilisation rate with medium voyage length and high utilisation rate with the longest voyage length. Table 2 presents these assumptions:

Each ship category is assigned compatible propulsion systems. Large ferries can use ICEs, FCs and BE propulsion systems, while the remaining ship categories are assigned to operate only with ICEs and FCs. Batteries have low mass and volumetric density, and their size and weight would make ships operating on the deep seas unfeasible [24,40,49,50]. Large ferries were explicitly selected for the analysis as the authors believe that smaller ferries already have a good potential of electrification, demonstrated with the numerous recent examples [61,62]. BE propulsion systems are more energy-efficient than ICE and FC and benefit from a more flexible operation that allows fast load changes, part-operation of the engines (such as just auxiliaries), lower noise impact and improved air quality (without any emissions) [63].

General cargo ships cover broad subcategories and are the most numerous ships among all four categories [3]. These ships are often equipped with four-stroke engines, providing higher power density and lower height than two-stroke engines [64]. Deep-sea shipping has traditionally been the domain of two-stroke engines because of the large fuel expenditures for these vessels, making fuel efficiency more critical than for large ferries or general cargo ships. For this reason, we also assumed the same for the bulk carrier and container ships in this analysis.

All engines are assumed to operate at 75% of the maximum continuous rating of (i.e. at 75% of their capacity output). A more detailed assessment will require an operational profile of the ship.

FCs are an alternative to ICEs in shipping. Unlike ICEs, FCs do not combust the fuel but undergo a chemical reaction that converts a fuel (as hydrogen, methanol or ammonia) to electrical energy. Two studies [43,45] present an overview of the available FC technologies for shipping, including alkaline, direct methanol, molten carbonate, or phosphoric fuel cells. According to these analyses, the most promising fuel cell technologies are LT/HT PEMFC and SOFC.

Moreover, we assume in this analysis the necessity of battery storage in conjunction with the FC systems, indispensable for such propulsion systems to increase their robustness [42,43]. Large-scale hybrid ships, combining BE and ICE exist, such as the Stena Jutlandica ferry that connects Gothenburg in Sweden to Frederikshavn in Denmark. The ferry has a power capacity of 25.9 MW and uses a 1 MWh battery with 3 MW output power for port manoeuvring and auxiliary systems as ventilation or heating [65]. Such example can provide a good indication on the sizing of the battery in fuel cell-battery combinations. Hence, we estimate the size of the batteries in combination with FC at 2–3 MWh for ferries, 1–1.5 MWh for general cargo and 3–4.5 MWh for bulk carrier and container ship.

Unlike an ICE that produces mechanical power as output, an FC produces electricity, so it needs to couple with an electric engine and a gearbox. The gearbox is needed to achieve the desired rotational speed of approximately 100 rpm while electric engines with high power outputs have rotational speeds above 1000 rpm. A system without a gearbox would also result in large dimensions for the electric engine, which can cause design issues [27]. Therefore all ships using electric propulsion, as FC and batteries, in our analyses, also include the cost of a gearbox.

Table 3 presents an overview of the costs associated with the propulsion systems, with a more detailed description of the different types of engines found in Appendix B. The lifetime for ICEs and electric propulsion unit is assumed to be 30 years, while the FC is estimated at 15 years. The O&M costs set as 2.5% for diesel, methanol and DME engines, 4.5% for LMG/LBG and ammonia, 6% for FC systems (including a stack change) and 1.5% for BE propulsion systems, expressed as a percentage of investment. The propulsion system efficiencies in the base case estimates are 40% for four-stroke engines, 45% for two-stroke engines, 55% for FC systems and 80% for BE systems.

2.3. On-board fuel storage and cost of lost cargo space

The fuel storage will have a more prominent role once the fuels change away from MGO. Currently, ships that do not run on fixed routes are refuelling in generally oversized tanks based on the spot price in the various ports along the routes, which allows for a high level of flexibility, but when other fuels replace MGO, some of the routines of refuelling and storing the fuel may change. An essential characteristic is that all the fuels that may replace MGO have significantly lower volumetric densities. However, since many of the storage tanks on-board of ships are oversized already, the reduced volumetric density may not always be an issue but will be case dependent. In the sizing of the fuel storage for this analysis, for simplicity, we consider a safety margin of 1.5 of the distance travelled for all on-board storages, including battery systems. Table 4 illustrates the costs used in this analysis. A detailed description of the storage requirements is available in Appendix C.

Because of the volume required to keep these new fuels on-board of ships, we developed a methodology to quantify the value of the reduced cargo space adapted from Refs. [40,69]. In the case of ferries, finding a representative cost proved difficult, as it had to be associated with some goods transported by such ships. Therefore, an average cost of the ferry ticket for standard articulated lorries travelling similar distances in Europe was considered, which is then split based on the volume of such an articulated lorry to determine a cost per volume lost. For general cargo and bulk carriers, the cost determined by Raucci [69] is used, in €/tonne loss of cargo. While this method suits the bulk carrier, it may not be the most suitable for general cargo ships, representing a broad category, transporting not just bulky items, but a variety of goods that cannot always be quantified by weight. However, this method is found sufficient for this analysis. We further determined the reduced cargo space for container ships using the twenty-foot equivalent unit average

Table 2
Characteristics of the four investigated ship categories.

Ships	Nominal propulsion capacity (MW)	Annual utilisation rate (hours)	Voyage lengths (hours)
Large ferry	11	1260, 2520, 3780	6, 12, 18
General cargo	6	3600, 4320, 5280	120, 240, 360
Bulk carrier	15	3600, 4320, 5280	240, 480, 720
Container ship	55	4320, 5280, 6000	240, 480, 720

Table 3
Investment cost in €/kW for ICE, FC, and BE propulsion systems, including engines and components. ICEs costs are for four-stroke engines (used in ferries and general cargo ships) and two-stroke engines used in the bulk carrier and container ships.

Component	Cost (€/kW)	Reference
ICE Diesel, HVO	240/460[a]	[66]
ICE Methanol	265/505[a]	Based on [15,52,66]
ICE DME, Ammonia	370/600[a]	Based on [27,50,66,67]
ICE LMG, LBG	470/700[a]	Based on [34,48]
ICE Hydrogen	470/700[a]	Assumed the same as LMG, LBG
Fuel reforming and evaporation	360	Based on [27,50,66]
PEMFC (LT and HT)	730	[66]
SOFC	1280	[66]
Electric motor	250	[27]
Gearbox	85	[27]

[a] Four-stroke engine/two-stroke engine.

freight rates between 2010 and 2018 [1] on comparable routes as the ones used in this analysis.Table 5 illustrates these costs:

2.4. Sensitivity analyses

The sensitivity analysis follows the same structure as the analysis and is split into three parts. The first part deals with the parameters that affect fuel costs. The second part varies the investment cost for the propulsion systems. The third part uses the cost deviations from part one and two to understand the overall impact on the TCO. The rest of this section details the varying parameters on all three parts.

2.4.1. Part one – fuel production

- *Increased electricity cost:* Off-shore wind investment cost increase by 50% to 49 €/MWh (from 33 €/MWh).
- *Grid electricity cost:* Using grid electricity instead of off-shore wind. The cost of electricity is the same as in the previous scenario, equivalent to producing electricity using the most expensive unit (biomass combined heat and power) [54] plus a cost for electricity transmission of 50% of the investment cost of the production unit. In this scenario, 8000 full load hours are considered for the electrolysis plant, eliminating the buffer capacity and hydrogen storage need.
- *High biomass cost:* Increasing the biomass feedstock price (applied to biofuels and bio-electrofuels). Biomass share of the total cost of the fuel cost has a high margin, and can significantly influence the total fuel cost. In this scenario, we analyse a cost of 10 €/GJ (instead of 6 €/GJ) biomass and 30 €/GJ for HVO specific feedstock (increased from 15 €/GJ).
- *High carbon capture cost:* Replacing point carbon capture with air carbon capture, by increasing the investment cost from 400 €/tCO_2 to 730 €/tCO_2 and the associated electricity consumption [56].
- *Low electrolysis cost:* Reducing the electrolysis investment cost. Electrolysers may benefit from significant cost reduction if deploying large capacities. Here we assume an investment cost of 400 €/kW instead of 600 €/kW.

Table 4
Cost of fuel storage on-board of large ferries (value in parenthesis is for general cargo, bulk carriers and container ships).

Fuel	Cost (€/kWh)	Lifetime (years)	Reference
Diesel, HVO	0.09 (0.07)	30	[52]
Methanol	0.14 (0.12)	30	[52]
DME, Ammonia	0.29 (0.23)	25	Based on [52,66]
LMG, LBG	0.94 (0.72)	20	[52]
Hydrogen	1.71 (1.29)	20	Based on [46,52]
Battery	250	15	Based on [10,50,63,68]

- *Increased efficiency for electrolysis.* The average efficiency is increased from 64% to 74%, by considering SOEL as the only electrolysis type.

2.4.2. Part two – capital costs propulsion system

- *Low fuel cell cost:* The PEMFC and SOFC investment cost is reduced from 730 to 400 €/kWe, which is the same as the lowest cost electrolysis technology estimated for 2030 in Ref. [55].
- *Low battery cost:* The battery system cost is reduced from 250 €/kWh to 150 €/kWh to reflect a case with a broader battery adoption in general.

The results for the sensitivity analyses on fuel production are described in Section 3.1.1, while the results for the sensitivity analysis on propulsion system cost are found in Appendix C of Supplementary material, that also includes further assumptions and results of the propulsion system sensitivity analysis.

2.4.3. Part three – TCO calculations

Section 3.2 combines:

- Results of the sensitivity analyses for fuel production.
- Results of the sensitivity analysis for propulsion costs. Moreover, this part analyses different efficiencies for FC and ICE propulsion.

3. Results

3.1. Fuel costs

The fuel cost analysis has resulted in a wide range of costs for the fuels analysed, with costs spanning from 69 €/MWh to 158 €/MWh in the base case and 33 €/MWh for electricity. Fig. 3 illustrates a split between biofuels, bio-electrofuels and electrofuels categories with some exceptions, with the former having the lowest cost and the latter the highest. In all fuel categories, diesel fuels are the most expensive, while methanol fuels are the least expensive. Fig. 3 also shows that infrastructure costs have a larger share of the fuel cost when cryogenic storage is required. Depending on the fuel production pathway, the infrastructure cost is the most visible for fuels as LMG and LBG, where it varies between 10 and 17% for, while for LH_2 this makes 23% of the final fuel cost.

Biofuel costs range between 69 and 95 €/MWh. For biofuels using dry biomass, the feedstock makes 35–50% of the final fuel cost, about 25% for LBG, while the more expensive fatty oils for HVO make up 65% of the total cost of the fuel. For bioLBG, the most significant cost component is the biogas plant, representing over 35% of the fuel cost.

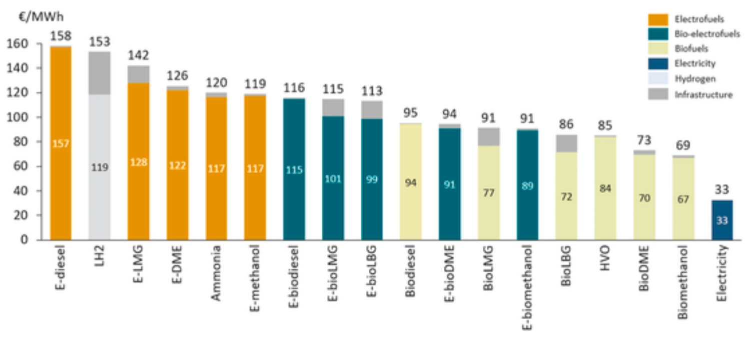


Fig. 3. Fuel costs in the base case.

Bio-electrofuels generally have higher costs than biofuels due to the hydrogen addition from electrolysers, bringing up the cost between 91 and 119 €/MWh. The overall input-output conversion efficiencies are in the same range as biofuels, but the significant difference compared to biofuels is the reduced amount of biomass required to achieve the same yields. For these fuels, the largest cost-component is electricity at around 25–35% of the fuel cost, followed by the electrolysers and hydrogen storage at 15–25% of the cost, while biomass is 15–20% of the total fuel cost.

Electrofuels and hydrogen have the highest cost in this analysis spanning between 120 and 158 €/MWh. The cost of electricity to produce any electrofuel represents 45–55% of the total cost. The cost of electrolysers and hydrogen storage is the second most significant cost component, at approximately 25–35% of the fuel cost. Carbon/nitrogen capture, fuel synthesis reactors, liquefaction and infrastructure, make up for the remaining part. Fig. 4 shows the cost structure for LMG ().

For LH_2, the highest cost component remains electricity at 40%, followed by electrolyser and infrastructure costs at 23% each. Liquefaction also takes a large share, at 18% of the total costs.

3.1.1. Sensitivity analysis

Deviations of the fuel costs presented in the base case may occur due to the uncertainties related to the price of electricity and biomass, plant design, investment costs or electrolyser efficiency and the impact of varying these parameters is shown in Figure 5.

In the first sensitivity analysis, a 50% higher investment cost for offshore wind increases the cost of bio-electrofuels by 11–17% and electrofuels (including LH_2) by 21–25% compared to the base case. Bio-electrofuels have a more distributed cost among technologies and feedstock costs, leading to bio-electrofuels being less affected by potential electricity price increases than electrofuels. A similar situation occurs

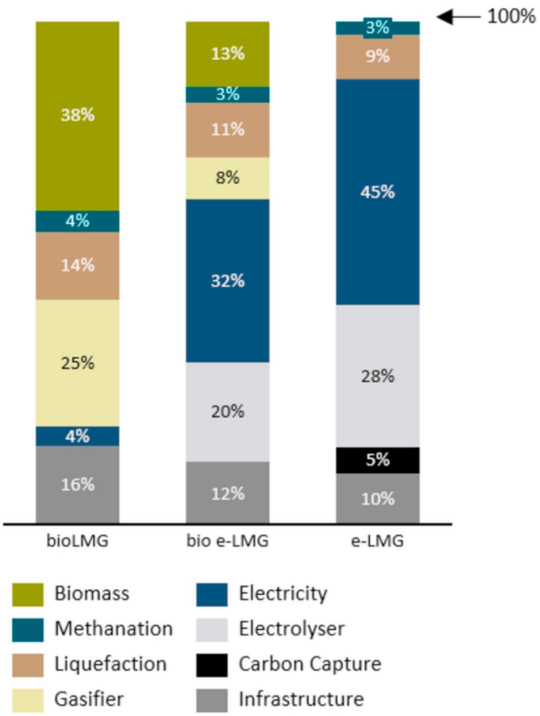


Fig. 4. Cost structure for LMG as biofuel, bio-electrofuel and electrofuel in the base case 2030.

when increasing all biomass feedstock costs to 10 €/GJ (except HVO, which uses a different feedstock). Biofuel costs increase by 17–34%, while the bio-electrofuel costs increased by only 10–14%. On average, the cost difference between bio-electrofuels in the base case and the scenario with high electricity prices is ~15 €/MWh_{fuel}, while for electrofuels the difference doubles to ~30 €/MWh_{fuel}.

The use of electricity from the grid, for hydrogen production, has the benefit of eliminating the difficulties with intermittent plant operation and the need for hydrogen storage and electrolysis buffer capacity. However, the more expensive grid electricity (at 49 €/MWh) has a more significant effect on the cost of the fuel than removing the hydrogen storage and electrolysis buffer capacity, such a measure increasing the bio-electrofuel and LH_2 costs by 4–6% and electrofuel cost by 7–8%. Hence, an electrolysis plant design with buffer capacity and hydrogen storage would in this context be more cost-efficient than a grid-connected plant if one would take the cost of electricity as the main determinator. In reality, it is less likely that such a plant could be technically feasible, as some level of grid connection may be needed to keep some of the processes online. Moreover, the energy system balancing potential of such a plant would be lost, as in the future, such fuel plants may have a more significant role than just producing fuels.

In the case of electrofuels (except ammonia) the cost of carbon capture has also been increased to represent a case where the fuel plants use the more expensive air carbon capture. With the higher costs for this technology, the fuel costs would increase by 12–19%.

The reduction in the investment cost of electrolysers has a moderate effect on the fuel costs by reducing the bio-electrofuels cost by 4–6% and electrofuel and LH_2 cost by 8–12%. The integration with other processes in the fuel plant influences the choice of electrolysis technology and the technology maturity level, parameters that have implications beyond the costs. Nevertheless, the increase in electrolyser efficiency has lower effects (5–8%) than the reduction of their capital cost, at least in this analysis setting. Combining these measures shows it can reduce the cost of bio-electrofuels by 8–11% and the cost of LH_2 and electrofuels by 12–16% compared to the base case. Figure 5 illustrates an overview of the associated costs with these sensitivity analyses.

The results in this chapter show that the most significant fuel cost influencers are feedstock costs (electricity and biomass) rather than the investment costs or technology efficiencies. This is integrated into the TCO analysis in Section 4.2.

3.2. The total cost of ownership

This section combines the fuel cost analysis results with propulsion and storage cost analysis (Appendix C) to indicate the lowest TCO for each ship. As overall results, biofuels in ICE propulsion systems have the lowest TCO and biomethanol in ICE is the only fuel-propulsion combination that can keep the cost closest to the same ship using MGO. For all ships, methanol in each fuel category has the lowest cost when used in ICE, but using any of the renewable fuels in the base case increases the TCO by 2–6 times compared to using MGO in the equivalent ship depending on the fuel and propulsion system used.

The TCO results show the cost segregation between biofuels, bio-electrofuels and electrofuels, which is an expected result since fuel costs make such a large part of the annual expenditures. Fig. 6 shows that in all combinations for all ships, fuel costs represent more than 50% of the total costs, except for BE ships, where the cost of the battery system has the largest share. For the other ships, the cost share of fuel storage is meagre compared to the other TCO components even in the case of the LH_2, where it does not take more than 9% in the most extended trips. With the cost of reduced cargo space, the two components take a maximum of 17% of the TCO, (except for BE ships), in which case the voyage length has limited influence on the TCO. For FC propulsion systems, the higher cost of the propulsion system combined with the lower fuel consumption reduces fuel expenditures on the TCO. Regardless of fuel

		Base case	Increased electricity cost	Grid electricity cost	High biomass cost	High carbon capture cost	Low electrolysis cost	High-efficiency electrolysis with low cost
Biofuels	Biomethanol	69			92			
	BioDME	73			98			
	Biodiesel	95			122			
	BioLMG	91			113			
	BioLBG	86			100			
	HVO	89			134			
Bio-electrofuels	E-biomethanol	89	104	94	101		83	79
	E-bioDME	94	110	100	107		89	84
	E-biodiesel	116	134	122	127		109	104
	E-bioLMG	115	132	121	125		108	104
	E-bioLBG	113	126	117	123		108	105
Electrofuels	E-methanol	119	149	129		142	108	100
	E-DME	126	156	136		149	114	106
	E-diesel	158	193	170		185	145	135
	E-LMG	142	172	152		160	131	123
	Ammonia	120	149	129			109	102
	LH_2	153	182	157			135	128

Fig. 5. Cost of fuels, including infrastructure in the base case and sensitivity analyses in €/MWh. The colour coding is within each fuel category box: biofuels, bio-electrofuels and electrofuels + LH_2. Green represents the lowest cost and red the highest cost. The cost of electricity is not represented here. (For interpretation of the references to colour in this figure legend, the reader is referred to the Web version of this article.)

Table 5
Cost of lost cargo space per type of ship and voyage length.

Voyage length	Ferry (€/m^3 of space loss)	General cargo (€/tonne of space loss/day)	Bulk carrier (€/tonne of space loss/day)	Container (€/TEU/trip)
Short	6	0.1	0.1	600
Medium	8			900
Long	10			1100

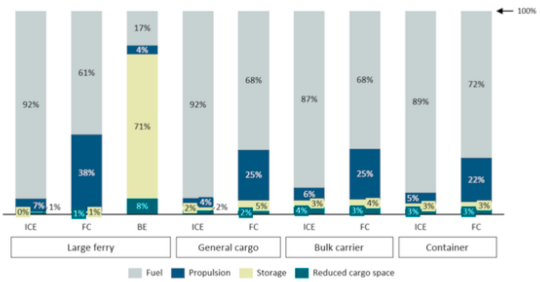


Fig. 6. TCO structure for all fuels with the medium utilisation rate and voyage length for the four categories of ships in the base case.

choice, ICE propulsion always has a lower share of the TCO than FC propulsion in the base case, independent of the utilisation rate or fuel used.

3.2.1. Reading guide and results for each ship

The following three sub-sections describe and illustrate the TCO results for each ship. Figs. 7–10 use a colour coding scheme illustrating the lowest TCO (green) to highest TCO (red). Each figure contains nine grey boxes split between fuel categories (biofuels, bio-electrofuels and electrofuels) combined with three different utilisation rates. The colour coding should be read within each box, from the most expensive to the lowest fuel-propulsion combination. Each figure includes the cost of the MGO in ICE alternative for comparison purposes.

3.2.1.1. Large ferries. The results for large ferries show that despite the reduced fuel consumption, FCs always have a higher TCO than ICEs. The average cost difference between the two propulsion systems is the highest among all ships, with 58% in the low utilisation rate, but decreasing to 9% as the trip length and utilisation increase.

Fig. 7 reveals that BE propulsion for large ferries has lower costs than most bio-electrofuels and electrofuels, except for e-biomethanol and e-bioDME in ICE. With the base case cost levels, BE propulsion is a more expensive option than biofuels in ICE, but cheaper than all FC propulsion with low to medium utilisation rates and voyage lengths. For all cases, BE in the base case is the lowest cost zero-emission solution, having 30–40% lower cost compared to using LH_2.

3.2.1.2. General cargo. The base case results for general cargo in Fig. 8 show reduced TCO differences between ICEs and FCs, from 10% in the low utilisation rate to reaching almost cost parity during the high utilisation rate for the same fuels that does not occur for large ferries. The large ferries travel fewer hours, so the more expensive FC propulsion system with higher fuel efficiency cannot offset the less-efficient but lower-cost ICE. For general cargo ships, the higher investment cost in FC propulsion is offset by the reduced fuel consumption compared to the equivalent ICE because of the longer time spent at sea and because it has a lower installed propulsion capacity. The lowest cost fuels in each category are all three types of methanol, followed by DME and HVO for biofuels. In the case of electrofuels ammonia shows a similar cost to e-methanol and e-DME.

3.2.1.3. Bulk carrier and container ships. Bulk carriers and container ships use more fuel than the rest of ships due to the high number of days at sea and operate more fuel-efficient ICEs. Figs. 9 and 10 show the base case TCO results for bulk carriers and container ships, with similar results. Unlike general cargo ships, the average TCO differences between ICEs and FCs are more considerable, starting from an average of 21% in the low utilisation rate to approximately 15% in the high utilisation rate for bulk carriers respectively 16% and 12% for container ships. The higher capital cost of FC propulsion is responsible for the significantly higher TCO. Thus, the efficient two-stroke ICE offsets the higher FC efficiency. Methanol shows as the lowest-cost fuel among all three fuel categories, but similar results are achieved when

	Utilisation/trip	Short			Medium			Long		
	Propulsion	ICE	FC	BE	ICE	FC	BE	ICE	FC	BE
	MGO	0.9			1.7			2.4		
Biofuels	Biomethanol	2.0	4.2		3.9	5.7		5.7	7.2	
Biofuels	BioDME	2.3			4.2			6.2		
Biofuels	Biodiesel	2.7			5.2			7.6		
Biofuels	BioLMG	3.0	4.9		5.4	6.8		7.8	8.7	
Biofuels	BioLBG	2.8	4.8		5.1	6.6		7.4	8.4	
Biofuels	HVO	2.4			4.6			6.8		
Bio-electrofuels	E-biomethanol	2.6	4.7		4.9	6.6		7.3	8.5	
Bio-electrofuels	E-bioDME	2.9			5.4			7.9		
Bio-electrofuels	E-biodiesel	3.2			6.2			9.2		
Bio-electrofuels	E-bioLMG	3.6	5.4		6.6	7.8		9.6	10.2	
Bio-electrofuels	E-bioLBG	3.6	5.3		6.5	7.7		9.5	10.1	
Electrofuels	E-methanol	3.3	5.3		6.5	7.8		9.7	10.3	
Electrofuels	E-DME	3.7			7.0			10.3		
Electrofuels	E-diesel	4.3			8.4			12.5		
Electrofuels	E-LMG	4.3	5.9		8.0	8.9		11.8	11.9	
Electrofuels	Ammonia	3.7	5.5		6.9	8.0		10.2	10.6	
	LH_2	4.7	5.3		8.8	8.6		13.0	11.9	
	Electricity			2.8			5.5			8.3

Low TCO M€/year – High TCO M€/year

Fig. 7. The TCO in M€/year for large ferries in the base case. The BE option is coloured differently but is comparable in terms of costs to all other cases in the ship travel category.

	Utilisation/trip	Short		Medium		Long	
	Propulsion	ICE	FC	ICE	FC	ICE	FC
	MGO	1.3		1.5		1.8	
Biofuels	Biomethanol	3.0	3.8	3.7	4.4	4.6	5.1
Biofuels	BioDME	3.3		4.0		4.9	
Biofuels	Biodiesel	4.0		4.8		5.8	
Biofuels	BioLMG	4.2	4.8	5.1	5.6	6.2	6.6
Biofuels	BioLBG	4.0	4.6	4.8	5.4	5.9	6.4
Biofuels	HVO	3.6		4.3		5.2	
Bio-electrofuels	E-biomethanol	3.8	4.5	4.7	5.2	5.8	6.1
Bio-electrofuels	E-bioDME	4.1		5.0		6.2	
Bio-electrofuels	E-biodiesel	4.8		5.8		7.0	
Bio-electrofuels	E-bioLMG	5.1	5.6	6.2	6.5	7.7	7.7
Bio-electrofuels	E-bioLBG	5.1	5.5	6.1	6.5	7.5	7.7
Electrofuels	E-methanol	5.0	5.5	6.1	6.3	7.6	7.5
Electrofuels	E-DME	5.4		6.5		8.0	
Electrofuels	E-diesel	6.5		7.8		9.5	
Electrofuels	E-LMG	6.2	6.4	7.6	7.6	9.3	9.0
Electrofuels	Ammonia	5.3	5.6	6.4	6.5	8.0	7.8
	LH_2	7.0	6.5	8.7	8.0	11.0	9.9

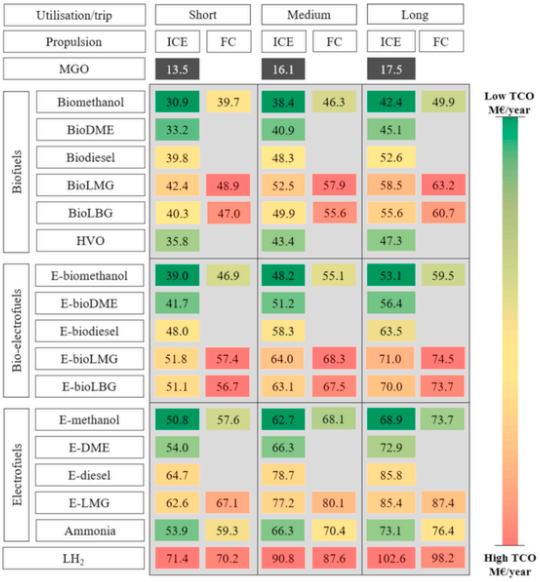
Low TCO M€/year – High TCO M€/year

Fig. 8. The TCO in M€ for general cargo ships in the base case.

	Utilisation/trip	Short		Medium		Long	
	Propulsion	ICE	FC	ICE	FC	ICE	FC
	MGO	3.2		3.7		4.4	
Biofuels	Biomethanol	7.2	9.7	8.9	11.3	11.3	13.3
Biofuels	BioDME	7.7		9.5		11.8	
Biofuels	Biodiesel	9.1		10.9		13.2	
Biofuels	BioLMG	9.9	11.9	12.2	13.8	15.0	16.3
Biofuels	BioLBG	9.4	11.4	11.6	13.3	14.3	15.7
Biofuels	HVO	8.2		9.8		11.9	
Bio-electrofuels	E-biomethanol	9.0	11.4	11.1	13.2	14.0	15.7
Bio-electrofuels	E-bioDME	9.6		11.8		14.6	
Bio-electrofuels	E-biodiesel	11.0		13.1		15.9	
Bio-electrofuels	E-bioLMG	12.1	13.8	14.7	16.1	18.2	19.2
Bio-electrofuels	E-bioLBG	11.9	13.6	14.5	16.0	17.9	18.9
Electrofuels	E-methanol	11.7	13.8	14.3	16.1	17.9	19.3
Electrofuels	E-DME	12.4		15.1		18.7	
Electrofuels	E-diesel	14.8		17.7		21.5	
Electrofuels	E-LMG	14.5	16.0	17.7	18.8	21.8	22.4
Electrofuels	Ammonia	12.5	14.2	15.4	16.8	19.3	20.2
	LH_2	16.6	16.5	21.4	20.7	27.5	26.2

Low TCO M€/year – High TCO M€/year

Fig. 9. The TCO in M€ for bulk carrier ships in the base case.



Utilisation/trip		Short		Medium		Long	
Propulsion		ICE	FC	ICE	FC	ICE	FC
MGO		13.5		16.1		17.5	
Biofuels	Biomethanol	30.9	39.7	38.4	46.3	42.4	49.9
	BioDME	33.2		40.9		45.1	
	Biodiesel	39.8		48.3		52.6	
	BioLMG	42.4	48.9	52.5	57.9	58.5	63.2
	BioLBG	40.3	47.0	49.9	55.6	55.6	60.7
	HVO	35.8		43.4		47.3	
Bio-electrofuels	E-biomethanol	39.0	46.9	48.2	55.1	53.1	59.5
	E-bioDME	41.7		51.2		56.4	
	E-biodiesel	48.0		58.3		63.5	
	E-bioLMG	51.8	57.4	64.0	68.3	71.0	74.5
	E-bioLBG	51.1	56.7	63.1	67.5	70.0	73.7
Electrofuels	E-methanol	50.8	57.6	62.7	68.1	68.9	73.7
	E-DME	54.0		66.3		72.9	
	E-diesel	64.7		78.7		85.8	
	E-LMG	62.6	67.1	77.2	80.1	85.4	87.4
	Ammonia	53.9	59.3	66.3	70.4	73.1	76.4
LH_2		71.4	70.2	90.8	87.6	102.6	98.2

Fig. 10. The TCO in M€ for container ships in the base case.

considering DME and HVO. Among the electrofuels, marginal TCO differences occur between e-DME and ammonia in ICEs as second and third lowest cost fuels in the category. Liquefied methane and hydrogen fuels have the highest costs in all fuel-propulsion combinations.

3.2.2. Sensitivity analysis

Increasing the electricity cost for fuel production by 50% does not change the ranking order between the fuels and propulsion systems in any of the ships, but in the case of large ferries, it makes the BE propulsion cheaper than all bio-electrofuels (except e-biomethanol) and electrofuels in ICE (see Figures D3 to D6 [1]). A high electricity price for all ships increases the average TCO of bio-electrofuels and electrofuels in ICE or FC by 10–20% but only by up to 8% for BE ferries. The increase in the electricity cost reduces the TCO of FC propulsion closer to ICE because FC can utilise the expensive fuel more efficiently, but not sufficiently in all cases to make FC a lower-cost option. The only case where FC can be a lower cost option is for general cargo ships that use the less efficient four-stroke ICEs.

As in the case of the high electricity price, increasing the price of biomass from 6€/GJ to 10 €/GJ reduces the TCO difference between ICE and FC, albeit not sufficiently to change the choice of the propulsion system, but sufficient to make the costs of biofuels and bio-electrofuels comparable in TCO. Biomethanol in ICE remains the lowest cost option among the biofuels using dry biomass as feedstock, while HVO is no longer a cheap option when considering the upper feedstock cost of 30 €/GJ (see Figures D7 to D10). In the case of bio-electrofuels, the ranking of the fuel-propulsion combinations remains the same as in the base case.

Besides fuel costs, the efficiency and investment cost of the propulsion system can be a significant influencer. In the sensitivity analysis, two optimistic cases for FCs (higher efficiency and low investment cost) and a pessimistic case are considered, where the efficiency of ICEs is increased while keeping the base case efficiency for FC propulsion.

Increasing the efficiency of FC systems to 60% reduces the TCO difference between ICE and FC propulsion across all ships. It makes the FC option for general cargo vessels to have a lower TCO when using bio-electrofuels and electrofuels with the high utilisation rate since these ships use the less-efficient 4-stroke engine, so the fuel savings are substantial. Large ferries have fewer hours at sea and a higher installed propulsion capacity, so the fuel savings are not sufficient to make FCs a lower cost option than ICE but do get on cost parity with ICE for some bio-electrofuels and electrofuels. For bulk carriers and container ships, using more efficient FC is not sufficient in all cases to achieve a lower TCO, due to the higher efficiency of the 2-stroke ICE, but high utilisation rates combined with the most expensive electrofuels, like ammonia or e-LMG show lower TCO for the FC propulsion. ICE keeps the lower cost for the remaining cases, with the most significant cost differences noticeable for the low utilisation rates with biofuels (see Figures D11 to D14).

The reduction of the investment cost to 400 €/kWe across all FC systems has similar effects as the increase in FC efficiency. As such, except for the low utilisation rates with the large ferry, FC propulsion is at least on parity or has a lower TCO than ICE propulsion for all ships and travelled distances. General cargo ships benefit the most because the already more efficient FC now has a lower cost. The most considerable differences occur for the high utilisation rates, of up to 15% lower cost for FC propulsion, while these gains decrease with lower utilisation rates. For bulk carrier and container ships, the TCO is marginally lower for FC, with the largest differences (of up to 7%) for the high utilisation rates with the most expensive electrofuels (Figures D14 to D18).

By assuming ICEs operate at higher efficiency (45% for four-stroke and 50% for two-stroke) without any efficiency increases on the FC side, then the TCO remains lower for ICE at all times, even in the case of general cargo ships. Figures D18 to D22 illustrate the sensitivity analysis for operating more efficient ICE versus a base case FC efficiency.

In the sensitivity analysis, we observe a trade-off between the cost and efficiency of the propulsion system, the number of days at sea, and fuel cost. Lower cost fuels (as biofuels) have lower TCO in ICE while more costly fuels (as electrofuels) have lower TCO than FC systems. A breaking point in the cost of fuel indicates the choice between one or another. For example, methanol (independent from which fuel category) in general cargo ships with the base case assumptions for the capital costs, the breaking point occurs at around 144 €/MWh$_{fuel}$ for the medium utilisation and trip distance. If the fuel cost is below this value, then the ICE propulsion has a lower TCO. If the fuel price is higher than this value, then FC propulsion has a lower TCO as illustrated in Fig. 11. Additionally, by taking the efficient FC case for the same ship, medium voyage length, then the breaking point would be at 104 €/MWh while in the case of low propulsion cost this would occur at around 50 €/MWh. These estimations are greatly affected by cost, utilisation and efficiency assumptions of the propulsion systems but can be an indicator for the choice of future propulsion systems depending on the cost of fuels.

Apart from the choice between ICE and FC, the analysis includes a potential lower-cost battery system for BE ferries. By reducing the cost of the battery system to 150 €/kWh (as described in Section 2.4 and Appendix C), BE large ferries can have lower TCO than all fuel-propulsion options, except biomethanol in ICE in both base case and high ICE efficiency. Compared to e-biomethanol and e-methanol, low-cost BE systems can achieve significant cost reductions, even compared to more efficient ICEs or low-cost FC systems. Fig. 12 illustrates the BE propulsion TCO with all three types of methanol used in large ferries in both ICE and FC and Figure D11 presents an overview of TCO for all fuel-propulsion combinations.

4. Discussion

Among the potential fuels proposed for the shipping sector, the analysis performed in this study shows that methanol, DME or ammonia have lower costs than other fuels in their respective fuel categories

[1] Dx tables can be found in Appendix D of supplementary material.

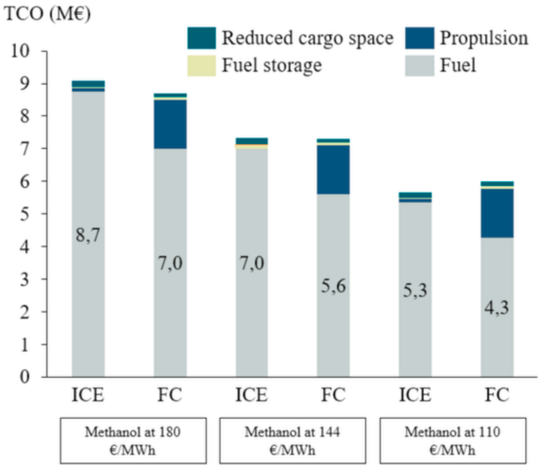


Fig. 11. Breaking point in the cost of methanol, showing where the costlier methanol options have a lower TCO when used in FCs instead of ICEs, in the base case, for the ship type general cargo.

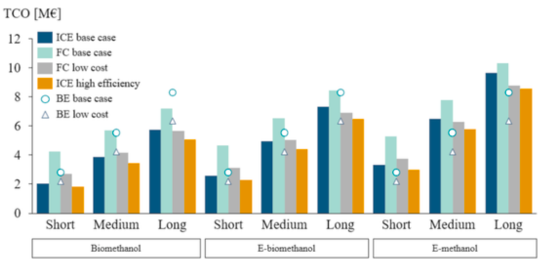


Fig. 12. TCO in M€ for large ferries using biomethanol, e-biomethanol and e-methanol in ICE, FC, BE for the base case compared to low FC propulsion cost, a case with high (+5%) higher ICE efficiency and the case of low-cost battery storage.

and that BE and FC can replace ICEs. From a TCO perspective, ICE will likely remain a competitive technology in shipping even if today's fossil fuels will be replaced and primarily if FCs, and battery systems for that matter, do not deliver from an economical and technological perspective.

Batteries have resulted as a potentially cost-effective option for large ferries than ICEs using bio-electrofuels and electrofuels, especially if the battery system costs decrease to levels below 200 €/kWh. BE large ferries may become a viable solution by 2030, given the recent and upcoming developments in automotive battery technology [70,71]. Perčić et al. [48] show that battery-electric vessel can have a lower cost than a fossil diesel-powered vessel in the Croatian short-sea shipping sector with a battery price of 200 €/kWh and electricity price of 78–200 €/kWh. However, one must bear in mind that the requirements for battery systems in ships are stricter than automotive which could motivate differentiated prices, needing improved cooling systems and fire safety measures that increase the cost [49]. Several ferries travelling shorter distances than analysed in this study already use BE propulsion [61,62], so a scaled deployment has the chance to improve the learning curve and reduce the investment costs. BE ferries appear less affected by electricity cost increases than using any of the electrofuels because they can use electricity more efficiently than any electricity-based liquid fuel can do. The results show that BE solutions may be viable even for medium to long voyages (12–18 h in the analysis). However, factors like charging times, battery degradation, charging infrastructure and the lack of knowledge on operating such ships on long distances indicate a need for further evaluation. Stena Line is preparing the retrofit of one of their ships to travel the distance between Gothenburg (Sweden) and Frederikshavn (Denmark) in 3 h solely using batteries [65]. Therefore, it is not unlikely to expect that by 2030 longer trips, as investigated in this analysis, to be achieved by full BE propulsion if achieving zero-emissions is the goal. If battery-electric vehicles are produced and charged with renewable electricity, this offers a very low climate impact alternative [72] and will eliminate exhaust emissions. However, a recent study for ships shows that when using a South Korean electricity mix, it was not possible to achieve a 50% reduction in GHGs [73].

A high-density liquid fuel is necessary for the rest of the ships, as batteries face difficulties when voyages exceed 12 h (or potentially even less). Liquid hydrogen was found by Horvath et al. [40] the least-cost option for all the ships analysed due to the low fuel production cost, at 38–49 €/MWh$_{LH2}$, achievable by a solar-wind plant in Argentina. We find a cost of 119 €/MWh only for the production and liquefaction in the base case and 153 €/MWh when including the infrastructure costs, which is within the range proposed by Grey et al. [35]. The main reason for this discrepancy is the electricity cost, as we account a cost of 33–49 €/MWh solely for electricity, which is a significantly more conservative option, but probably more realistic, as not all fuels can and will be produced in a single location. When accounting for the cost of storing LH_2 on board of the ships, it becomes one of the most expensive fuel-propulsion combinations. The cost of storing LH_2 is still unclear [46], but likely safe to assume that it will always be more expensive than for all the other liquid fuels in this analysis. When used in ICEs, LH_2 can reduce exhaust emissions [74] while for FCs, the only exhaust is water vapour. Produced from renewable energy, LH_2 has the potential to reduce GHGs significantly in a life cycle perspective [75].

Liquefied methane fuels as LBG and LMG show high TCO for all ships, mainly due to the high infrastructure costs to handle these fuels and expensive storage. LMG and LBG suffer from issues with methane leakages in production, distribution, bunkering and propulsion. The fuel cost calculations do not include methane leakages, which may have increased the fuel cost. More importantly, methane has a high GWP potential of about 30 times that of CO_2 over 100 years, making LMG doubtable as a sustainable solution, without controlling potential leakages. Existing studies find liquefied methane as a transition fuel to methanol or hydrogen propulsion [66], while [13,24] raise the question of climate impacts and call for reducing the uncertainty linked to methane leakages. Moreover, biogas is also a limited resource often desirable in other energy sectors as power, heat or industry, showing better socio-economical results [76]. Based on these considerations, we see challenges with large-scale use of any methane fuels in the maritime sector.

The most similar fuels to existing marine fuels in this analysis, from a chemical property perspective, are diesel and HVO. Both can benefit better from the existing port infrastructure but suffer from high production cost. FT diesel has the highest cost in each fuel category, while HVO does not appear as an expensive option (actually showing low TCO with two-stroke engines), it is sensitive to fluctuations in biomass price and can become the most expensive biofuel. Due to the high production costs and large feedstock consumption, we do not find FT diesel or HVO feasible for the maritime sector.

Three fuel candidates with low TCO results are left: all types of methanol, DME and ammonia. Ammonia has been circulated recently as one of the preferred solutions for replacing fossil fuels in shipping. The shipping company Maersk has listed ammonia together with biomethane and alcohols as the most promising solutions to net-zero emissions [77] and other studies [25,50,53] target ammonia as the most suitable, or among the recommended solutions for net-zero shipping [35]. Our analysis shows that ammonia has a marginally higher TCO than using e-methanol in ICE, which mainly relates to the increased capital costs for ICE, such as the need for a fuel reformer and evaporator. Engine manufacturers must also address issues as the potential of N_2O emissions, a compound with a GWP potential of 300 times that of CO_2 over 100 years [78] besides the NO_x emissions and unburned fuel in the exhaust [25], while the shipping industry must also deal with the safe handling of this fuel related to its toxicity. Therefore, ammonia may be the lowest cost solution if the goal is to eliminate the carbon component.

DME shows low TCO results in the analysis, similar to the ammonia in ICE. It benefits of an improved volumetric density compared to methanol but requires pressurised storage as ammonia. Unlike ammonia, a common chemical traded worldwide, DME is a new fuel for the maritime sector with no dedicated infrastructure and little knowledge on the handling of the fuel on-board. However, the engine manufacturer MAN claims to produce such an engine if demand exists [67]. One of the advantages of DME combustion is the low emission levels of NO_x and PM compared to diesel combustion [79].

Methanol shows in all types of ships and voyage lengths the lowest TCO, due to the reduced production, storage and propulsion costs. With some types of methane fuel production pathways, it is one of the fuels that require the least amount of biomass and hydrogen in the production process in their fuel categories. Since it is more hydrogen efficient, it is also the least affected by electricity price fluctuations. Another benefit of methanol is the simplicity of storage, requiring only a non-pressurised steel tank, making it suitable for retrofitting older ships [35]. The storage infrastructure for this fuel is well-deployed worldwide but mainly coupled to the chemical industry [15], but further development is necessary [80]. In most cases, existing MGO/HFO infrastructure may be retrofitted to handle methanol, with minor modifications and low cost, especially if compared with liquefied methane fuels [15,81]. Methanol has good combustion properties and low GHG emissions when produced from renewable sources and low emissions of NO_x and PM emissions compared to diesel when used in ICEs [17,82].

Independent of which renewable fuel (or fuels) will prevail, the shipping sector must be ready to pay a significantly higher price for a renewable fuel on a fuel market with generally higher prices than today [29,34,35]. Fuel prices may be lower than the values found in this analysis if produced in preferred regions, but that will not change the ranking between fuels. If hydrogen can be produced for a low cost, then methanol, ammonia and DME may also have a lower cost in those regions. Transporting, storing, and developing an infrastructure for methanol, ammonia, and DME would also be cheaper than hydrogen, which is why they are the primary recommendation of this analysis.

The availability of future renewable fuels may be a limitation [80] because of the massive amounts of biomass and renewable electricity needed for these fuels, as illustrated in Fig. 13. Electrofuels are often promoted as a replacement for fossil fuels, but bio-electrofuels from biomass gasification and hydrogenation should be further researched and demonstrated as a solution for balancing the available resources while also achieving a potentially lower fuel cost.

Regarding the propulsion system, four key elements should guide the choice between ICE and FC: the fuel cost, the time spent at sea, the fuel efficiency and cost of the propulsion system (the size of the additional battery in FC systems makes little to no difference). There is a trade-off between the cost of fuel and the cost of the propulsion system. Cheaper fuels make ICE a more desirable option and do not justify the investment in FC. On the other hand, the more expensive electrofuels may favour FC, as shown in Figure 11. Secondly, FCs make more economic sense with an increased number of days at sea and high utilisation, where the lower fuel consumption offsets the higher cost of FCs. Not the least, expensive FC systems may be a solution for replacing four-stroke engines in general cargo ships if the propulsion system can achieve efficiencies of 15–20% higher than the ICE, but the more efficient two-stroke engines in bulk carriers would require significant FC improvements to make it worthwhile to switch technology. An operational profile analysis for these propulsion systems may reveal different results when including variable efficiencies at different loads and speeds. However, FCs require either higher fuel efficiency than ICE or low investment costs, both likely challenging by 2030 given the technology readiness level.

Fig. 13. The annual fuel consumption needed for a container ship with the highest utilisation rate equipped with a 55 MW two-stroke ICE in all three methanol production pathways.

This article offers a detailed and systematic comparison overview of the costs for advanced fuels and propulsion systems in future fossil-free ships. A similar comparison focusing on life cycle environmental impacts that also include the production of propulsion systems lacks in the scientific literature even if several studies have been done in recent years [17,48,73,75,83]. This complementary view would be needed as well for all involved in the task of selecting future fuels and propulsion systems for ships.

5. Conclusion

This study analyses the potential of renewable fuels to replace fossil fuels in four different types of ships: large ferries, general cargo, bulk carriers and container ships. The results indicate that BE ferries can be cost-competitive to the alternative fuels investigated. For the three other ship categories, methanol, followed by DME and ammonia, show a low total cost of ownership.

The propulsion system choice is sensitive to the utilisation rate and the cost of future fuels. Consequently, the results indicate that four-stroke marine engines can be replaced by fuels cells if efficiencies are 15–20% higher, but that two-stroke engines may continue to support deep-sea travel.

CRediT author statement

Andrei David Korberg: Conceptualisation, Methodology, Software, Formal analysis, Investigation, Resources, Data Curation, Writing – Original Draft, Writing – Review and Editing, Visualisation, Project administration, Funding acquisition. Selma Brynolf: Validation, Resources, Visualisation, Supervision, Writing – Review and Editing, Visualisation, Funding acquisition. Maria Grahn: Validation, Supervision, Writing – Review and Editing, Visualisation, Funding acquisition. Iva Ridjan Skov: Visualisation, Supervision, Funding acquisition.

Declaration of competing interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

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Permission was attained for displaying the container ship icon in Fig. 13 by purchasing a license through Vexels.com.

Appendix A. Supplementary data

Supplementary data to this article can be found online at https://doi.org/10.1016/j.rser.2021.110861.

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7 SYNTHESIS OF THE RESULTS

The analyses in the three studies provided individualised solutions for the problems raised within. Therefore, this chapter combines the results to answer the research question of feasibility for renewable fuel pathways as part of sustainable energy systems.

Throughout the three studies, the goal was to identify renewable fuel pathways that could combine the components described in Chapter 5 in an efficient manner that could minimise the biomass use and reduce the overall energy system costs (Study 1 and Study 2) and to determine the lowest total cost of ownership for a specific part of the transport sector (Study 3). Although these studies differ in methodology, spatial and temporal context, their results can be synthesised in a set of inter-related pathways that can contribute to defining generalised conclusions. Due to the nature of the analyses and their outcomes, the synthesis of the results divides them into pathways for stationary units, for which specific types of renewable gas emerge as the essential fuels, and transport, which favours renewable liquids.

7.1 RENEWABLE GAS IN STATIONARY UNITS

Study 1 and Study 2 inquire about the role of anaerobic digestion and thermal gasification for fuel production as a method for utilising biomass resources. Both studies refer to Denmark as a case study in the context of a 100% renewable energy system model in 2050, with the second study also including a EU28 carbon-neutral energy system model for the same year as an additional case study. The two articles use energy system analysis and provide the foundation for Pathways #1 and #2.

7.1.1 PATHWAY #1 – BIOGAS IN STATIONARY APPLICATIONS

Study 1 starts from the premise that biogas is a limited resource and should only be used in the energy sectors where it is the most feasible. The study results indicate that when available, biogas and biogas-derived biomethane can reduce the energy system costs compared to systems without biogas, but only when used in power and district heat production or for industrial sectors. The study emphasises that biogas plants are mainly a waste handling method for hazardous inputs that can also produce a combustible fuel. For this reason, biogas is not interpreted as a central resource for any of these sectors but rather as a complement to VRES and electrification. Due to the type of feedstock they use, biogas and biogas-derived biomethane can be cheaper alternatives to equivalent gaseous fuels from dry biomass such as woodchips or straw, but their costs are also dependent on who should be paying for the waste handling – the agricultural sector or the energy sector.

Raw biogas contains both methane and CO_2, which may be a limiting factor in specific applications, relating to storage and combustion difficulties. Independent of which sector uses the fuel, if biogas is used directly, then biogas plants must be located in the proximity of the demand or on sites where local distribution networks may be established. On the other hand, purifying biogas to biomethane quality can be beneficial, as it can make use of a typical gas grid. Biomethane can reduce energy system costs in the same manner as biogas, and despite the higher production cost, biomethane can also be a low-cost CO_2 sink, an essential resource in the context of renewable energy systems with limited point CO_2 sources.

Future renewable and carbon-neutral energy systems will require significant amounts of renewable gas to complement electrification and replace natural gas. Systems using biogas or biogas-derived biomethane show lower overall dry biomass consumption and total costs than energy systems without biogas. Stationary applications in power and district heating, such as CCGT and combustion in industrial processes, can benefit the most from biogas and biomethane since the alternative gases from dry biomass or PtM are more expensive and more energy-intensive to produce. This closely relates to the fact that society is more willing to pay for a fuel that is not drastically more expensive than today's natural gas. Based on these aspects, Study 1 defines Pathway #1, illustrated in Figure 9.

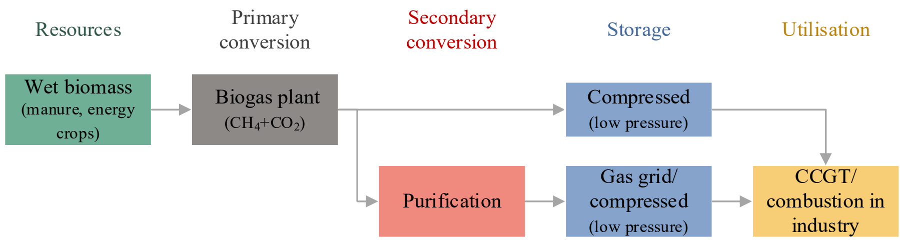

Figure 9: Pathway #1 – Raw biogas and biomethane for electricity, district heat and industry.

7.1.2 PATHWAY #2 – GASIFICATION TO COMPLEMENT BIOGAS

Biomass is a resource for the energy system. It has many functions outside the energy system, but parts can and should be used for energy purposes as long as the consumption is within sustainable limits. Since it is a limited resource, biomass should only be used in parts of the energy system where it is most needed after conversion to a liquid or gas fuel.

Significant gas demands will remain in all types of energy systems. Pathway #1 identified that biogas and biogas-derived biomethane should be prioritised due to their non-reliance on dry biomass resources and because their primary role is to handle the waste. However, biogas depends on limited agricultural output, so it needs to be complemented by other gases. All available PtM solutions remain expensive and require more energy inputs for production, as described in Study 1, so the other option is syngas produced from the thermal gasification of woody biomass, straw and energy crops. Combustible syngas is generally a more expensive option than biogas or biomethane from manure and other waste, but a combination of both resources appears necessary for supplying future gas demands.

As in the case of biogas, raw syngas may entail local production and utilisation, which can incur disadvantages in terms of capacity, storage and flexibility but may also lead to more efficient use of resources and reduced fuel transport costs. The alternative is to upgrade syngas to biomethane quality and combine it with biomethane from biogas in a typical gas grid, but this induces high costs and reduced energy efficiency as methanation causes thermal losses ultimately reflected in the cost of the fuel. In such a scenario, upgraded syngas will have a similar production cost as the PtM pathways.

Nevertheless, both raw and upgraded syngas should be considered for future sustainable energy systems, although the former should be prioritised. Since syngas is complementary to biogas or biomethane, the fuel application remains the same: power production, district heat production and industry. Based on these findings, the results in Studies 1 and 2 define Pathway #2, illustrated in Figure 10.

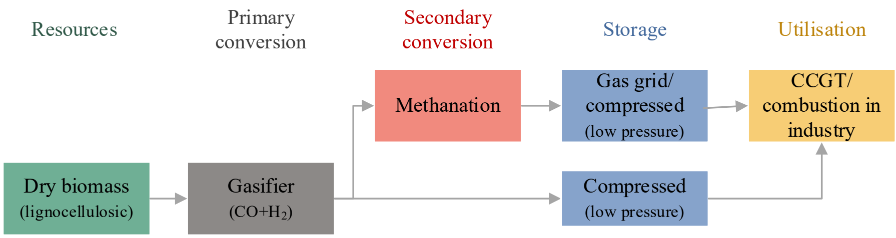

Figure 10: Pathway #2 – Raw and upgraded syngas to supplement biogas in the same energy sectors.

7.2 RENEWABLE LIQUIDS IN TRANSPORT

In the transport sector, all three studies contribute to defining Pathways #3 and #4. Study 1 contributes indirectly to these pathways by identifying methanol as a more feasible option for satisfying transport demands than electromethane from biogas. Study 2 further inquires how thermal gasification and carbon capture contribute to supplying different transport demands. Furthermore, with a different perspective to the first two research articles, Study 3 builds on Study 2 to examine potential fuel alternatives for the shipping sector through a techno-economic analysis focusing on both production and utilisation.

7.2.1 PATHWAY #3 – BIO-ELECTROFUELS IN TRANSPORT

Alongside utilisation in power, district heating and industry, the analysis in all three studies identified significant potential for dry biomass to supply transport demands. Study 2 indicates that despite the extensive biomass consumption in systems with thermal gasification, these have lower overall biomass consumption than systems predominantly based on CO_2-electrofuels since they operate more efficiently.

All three studies identified liquid fuels from thermal gasification of dry biomass as enabling more efficient resource consumption and cost reductions than similar transport fuels produced from biogas or carbon capture. Biomass-based liquid fuels have lower production costs than CO_2-electrofuels as biomass is a lower cost hydrogen source than electrolysis, which translates into a more efficient system operation since power plants require less fuel and the energy system needs less VRES capacity. From a systems perspective, bio-electrofuels thus represent a solution to deal with the potential future scarcity of low-cost carbon sources since they use the carbon available in biomass.

Syngas can be converted to methanol, DME, jet fuel and FT liquids. Studies 2 and 3 found that all syntheses are feasible, but the final applications differ depending on the transport sector. Methanol synthesis has a higher conversion efficiency and better synthesis flexibility than FT fuels; thus, it is the lowest cost option in road transport and shipping. The analysis in Study 2 also revealed that FT liquids may be an alternative in aviation, considering that methanol-to-jet fuel conversion technology is still in the early stages, in contrast to the more mature FT jet fuel. These results define Pathway #3, illustrated in Figure 11.

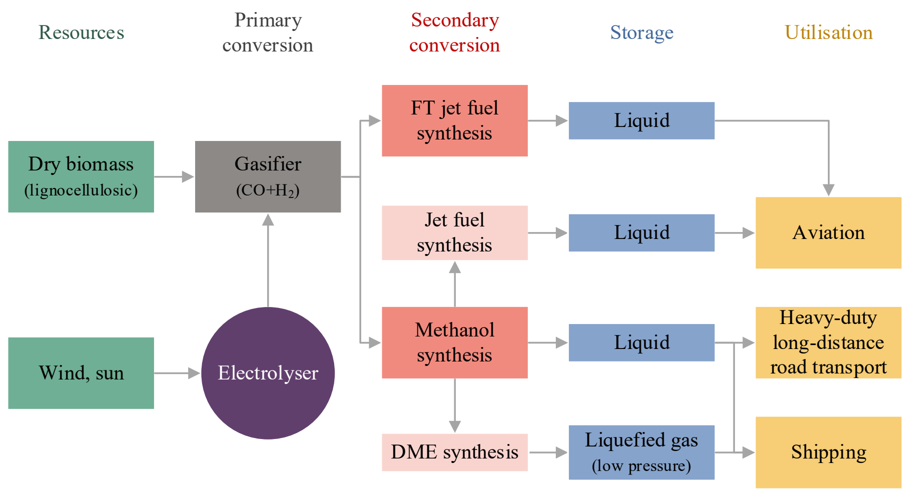

Figure 11: Pathway #3 – Bio-electrofuels in transport.

7.2.2 PATHWAY #4 – CO_2-ELECTROFUELS AND ELECTROAMMONIA TO COMPLEMENT BIO-ELECTROFUELS

Biomass is an efficient resource for the energy system, but it cannot supply all demands in stationary applications and transport. A combination of biomass and non-biogenic electrofuels is therefore deemed necessary. It is, however, unclear how much CO_2 and ammonia are necessary to complement bio-electrofuels since this depends on the future level of electrification and available biomass.

The availability of sufficient non-fossil carbon sources may be one of the constraints for the large-scale deployment of this technology, which is another reason bio-electrofuels should be prioritised. Future power plants in energy systems with large-scale VRES integration may not be suitable sources of carbon due to their intermittent operation. Industrial sources (or biogas/syngas upgrade) may be better candidates, as well as DAC, but these may be either insufficient or expensive.

CO_2-electrofuels can produce the same outputs as bio-electrofuels and have the same applications in the transport sectors. In addition to hydrocarbons, Study 3 identifies ammonia as an alternative to methanol in shipping. Ammonia does not rely on carbon sources, making it more resilient in plant location and production capacities. The ASU is also significantly less costly than air carbon capture and represents a small share of the final fuel cost. Based on these aspects, the results in Studies 2 and 3 define Pathway #4, illustrated in Figure 12.

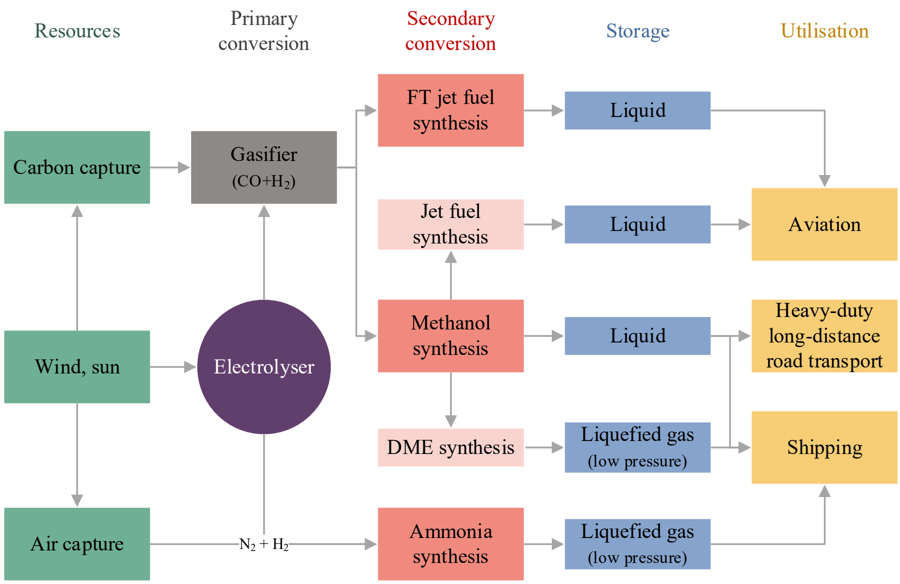

Figure 12: Pathway #4: Carbon and nitrogen electrofuels to complement bio-electrofuels.

7.3 SUMMARY OF THE FOUR PATHWAYS

The four pathways identified throughout this chapter represent the main results extracted from the three studies and answer the research question. This chapter summarises the pathways accordingly and illustrates them in a complete block in Figure 13.

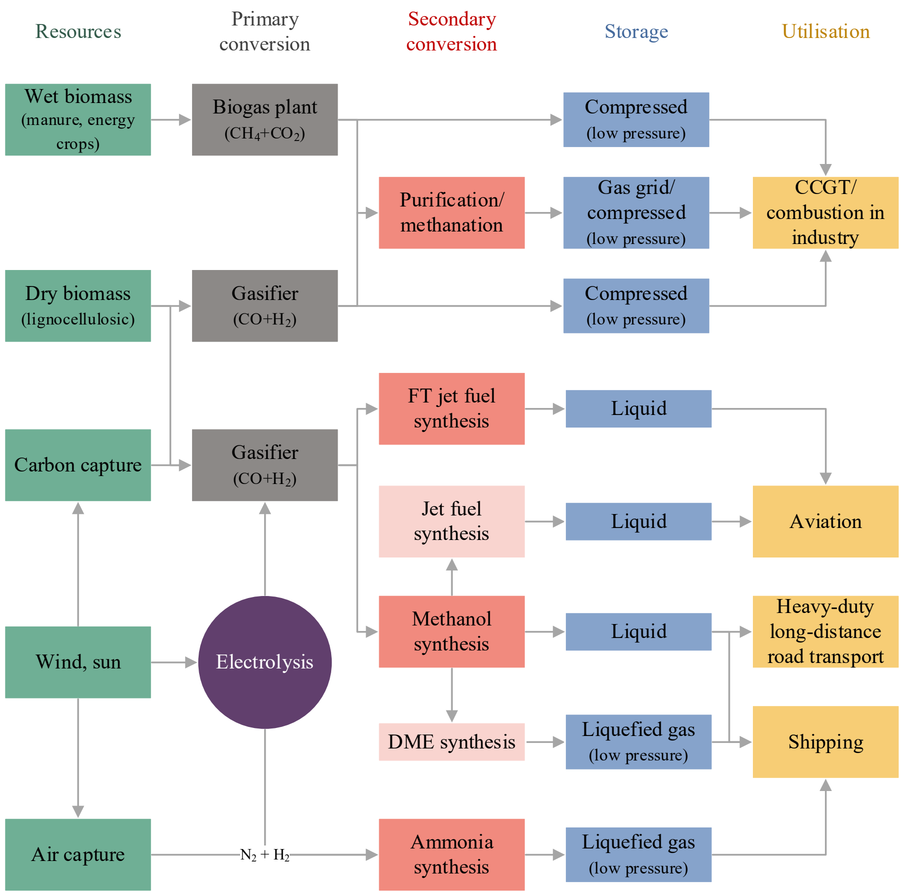

Figure 13: The four pathways for renewable fuel production in a system perspective.

The research outcomes indicated that both wet biomass (manure or organic waste) and dry biomass (straw or woody feedstock) could have significant potential when converted to gaseous fuels. The resulting products, biogas and syngas, should be primarily used in stationary applications for power production and have applications for district heat production and industrial purposes, depending on the demands. Wet biomass in biogas plants can reduce the total energy system costs and help keep low dry biomass consumption. However, the results also revealed that dry biomass could contribute to the supply of additional gaseous fuel for stationary units through thermal gasification. Biogas from anaerobic digestion and syngas from thermal gasification can be used directly in stationary units, but both fuels can also be upgraded to methane quality. Supporting a conventional gas grid based on methane may be a more practical solution, with the additional potential of CO_2 sinks. However, future decentralised energy systems may establish local biogas or syngas grids to achieve lower fuel costs and higher fuel efficiency.

Thermal gasification can be again a cost- and energy-efficient solution when combined with electrolytic hydrogen to produce bio-electrofuels in transport. The dual role of this technology calls for the careful balancing of dry biomass resources between producing syngas in stationary units and producing liquid fuels for transport. This balancing should account for other critical energy system measures, such as the electrification levels, total transport demands, technology readiness level, and alternative fuel availability. CO_2-electrofuels can complement bio-electrofuels, and although these do not rely on biomass resources, the extensive use of CO_2-electrofuels results in less efficient system operation. In either case, CO_2-electrofuels remain necessary as a complementary method that deals with supplying transport demands that cannot be satisfied by bio-electrofuels.

Independent of the primary conversion pathways, methanol is generally a lower cost option than FT fuels or methane in transport applications. However, the results differ depending on the end-use transport sector. In aviation, jet fuel from methanol-to-jet-fuel synthesis has a similar production cost as jet fuel from FT synthesis. In road transport and shipping, it is methanol and LMG that indicate the lowest fuel costs. Study 3 builds on these results and finds that, from a total cost of ownership perspective, LMG is one of the more expensive fuels when cost aspects like bunkering infrastructure, propulsion and on-board storage are accounted. The detailed techno-economic analysis in the third study confirmed methanol as one of the least expensive fuels in shipping along with ammonia and DME at similar costs for all ships. Thus, electroammonia can complement methanol bio-electrofuels or methanol CO_2-electrofuel. With this line-up of renewable end-fuels, it can also be concluded that all cost-efficient pathways illustrated in Figure 11 must include low-cost storage and infrastructure. None of the high-pressure compressed or liquefied fuels described in Chapter 5 is economically feasible.

8 DISCUSSION

The synthesis of the three studies in Chapter 7 answered the research question: *Which are the feasible renewable fuel pathways that integrate with sustainable energy systems?* While the outcomes of the studies are clear in the messages they convey, this chapter discusses the results to strengthen this thesis's overall conclusion. The aspects handled in this chapter refer to:

- the overall use of resources in the context of future fuel demands
- the potential of gasification
- the willingness to pay for renewable fuels
- the choice of end-fuels
- other biomass conversion processes not included in the three studies

Balancing the supply and demand

One of the most debated topics in any type of highly renewable energy systems is the availability of sufficient resources to meet future energy demands. All three studies raised the issue of limited resources, but it was not the aim of any of them to determine and quantify the optimal use of resources. Instead, the goal was to identify which solutions are most feasible by accounting for technical, economic, social and environmental concerns.

Biomass can be considered one of the most critical resources and an indicator of sustainability in general. Study 1 and Study 2 indicated that both wet and dry biomass resources would play an essential role in supplying gas demands in future energy systems. Although often simplified when discussing renewable fuels, any future sustainable energy systems with high shares of VRES will still require significant power plant capacities to deal with the variability of wind and solar. Even though power plants are not the only option for ensuring flexibility, they will likely retain an essential role in balancing energy systems in combination with other measures such as inter-connections, demand-side management and large-scale energy storage [129]. Sorknæs et al. [4] analysed the role of grid-scale batteries on an energy system level and found that batteries cannot be sufficient to balance the large-scale integration of VRES fluctuations in a cost-efficient manner, even when assuming the lower boundary investment cost, nor can demand-side management solutions shift enough capacity to integrate significantly more VRES. Thus, the authors indicate that flexible power production units remain necessary to produce enough electricity to meet non-flexible demands.

Future energy systems should have reduced overall gas demands due to the increased electrification levels compared to today's energy systems; this is one of the primary measures to replace fossil fuels and reduce emissions. However, extensive electrification is most likely to occur in the transport and industry sectors, which, by nature, are consumers rather than producers. On the other hand, power plants contribute actively to the electricity mix, and with the increased levels of VRES and electrification, these also require more fuels to balance variability. Figure 14 illustrates how the overall demands for liquid and gaseous fuels are projected to decrease by 2050 in both types of energy systems, yet the gas demands for electricity production (in power plants and CHP) are expected to be 60% higher than, and perhaps more than double, those in existing energy systems.

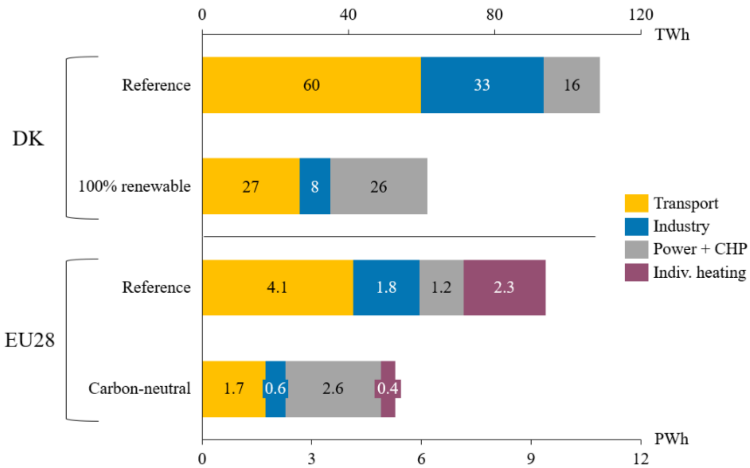

Figure 14: Liquid and gaseous fuel consumption and distribution per energy sectors in reference scenarios for 2015 [130] *and 2020 [4] versus 2050 [2] modelled in EnergyPLAN. Direct electricity and biomass consumption are excluded.*

With future increased gas demands for electricity production, the results in Study 1 and Study 2 become even more critical in the overall scheme of sustainable energy systems. The consumption of gaseous fuels in electricity production is comparable to or even higher than the liquid fuels for transport, underlining that future energy systems' design must not underestimate the demands for power generation fuels.

The debate on straw

The findings in Study 1 indicate that biogas should be used directly where possible, preferably in stationary applications for electricity production and heat or industry where needed. Biogas feedstocks are typically residues from animal agriculture, organic waste from industry or the organic fraction of municipal solid waste, while some energy crops such as corn and beets can also be used for this purpose.

Study 2 builds on the findings in the first study and highlights that syngas from thermal gasification of dry biomass can supplement biogas in the same applications.

The feedstocks for this process can include forestry products, energy crops and solid agricultural residues such as straw or stubble. However, these agricultural products can also be digested in biogas plants, and this is an important consideration, especially in countries like Denmark, as the country is relatively rich in this type of resource (59 PJ out of the total of 219 PJ/year, according to Figure 6 in Chapter 5.1.2). When used in biogas plants, straw can increase methane yields by approximately 30% [83], but not all of the energy content in straw can be converted into methane; rather, the conversion efficiency is limited to about 60%. Of the remaining unconverted input, about 40% needs to be returned to agricultural fields to complete the carbon cycle in the soil, while the remaining can be gasified to syngas. On the other hand, if all the straw were to be gasified, then the conversion efficiency to syngas would reach approximately 80% [83]. Moreover, the biochar by-product of gasification may be used to maintain the carbon balance in the soil, with improved long-term carbon retention compared to disposing of straw in fields [131–133]; this would also increase the amount of straw that can be used for energy purposes.

At this point, it is unclear which solution might be preferable. For the time being, biogas plants are the more mature technology than gasifiers, but the addition of straw still poses challenges as this is not yet a large-scale solution [95,96]. On the other hand, gasification has yet to be proven at a large scale, but the combination with straw input appears to have a higher conversion rate to syngas.

If biogas plants are the technology of choice to convert this resource, this will impact biogas prices, making this fuel more expensive than calculated in Study 1. An increase in biogas yields by 30% would not be sufficient to cover Danish gas demands in 2050, so the combination with gasifiers will likely remain necessary. Since gasifiers remain necessary even in combination with biogas plants, it may be a more efficient solution to reserve straw for this conversion process. However, if biomethane is preferred from an end-fuel perspective, it may be more economical to produce biomethane by converting biogas rather than syngas.

Scrutinised from the Energy Efficiency First perspective, and as confirmed in other studies [42,134], straw appears more valuable when combined with gasification and subsequent combustion or fuel synthesis. Such considerations must also include the environmental aspect of soil quality improvement and carbon sequestration that gasification can offer. For these reasons, thermal gasification for power, heat and industry was defined as Pathway #2, but further research is necessary to determine the most energy-efficient method for converting straw.

The pivotal role of thermal gasification

Thermal gasification of biomass can bring positive contributions to energy systems. Lester et al. [43] confirm that bio-electrofuels are more economically attractive than CO_2-electrofuels, while Connolly et al. [38] claim that thermal gasification is a transition technology that will only be viable until the future price of electricity is lower than that of biomass. However, the three studies included in this dissertation indicate that it will be quite challenging to reduce the price of electricity to below that of biomass, despite a projected price increase over time [135,136], and that even with high biomass prices, electricity will still be more expensive.

The transition towards renewable fuels has already started. However, there are still few ongoing demonstration projects on thermal gasification [98], and more focus seems to go towards using hydrogen as end-fuel or focusing instead on carbon capture and hydrogenation [137], which indicates that thermal gasification does not receive enough support and is constrained by inadequate legislation. There is a danger that society may skip this technology and go straight to the more expensive CO_2-electrofuels. While this is a possibility, the results throughout the three studies show that thermal gasification can increase the energy system efficiency while decreasing its costs. Compared to energy systems using bio-electrofuels from gasification, systems using CO_2-electrofuels from carbon capture have higher system costs because of their higher hydrogen demands. CO_2-electrofuels require more VRES capacity, which requires more fuel plants, thus increasing resource consumption and energy system costs. On the utilisation side, the cost differences between bio-electrofuels and CO_2-electrofuels can determine the choice of the propulsion system. In shipping, methanol bio-electrofuel can show lower cost in an ICE setup, while methanol as CO_2-electrofuel may show lower cost in an FC setup.

Apart from the increased hydrogen demand, energy systems with predominantly CO_2-electrofuels require reliable and low-cost carbon sources that can support future transport fuel demands. Such carbon sources may come from various non-fossil sources, including iron and steel production, cement plants, biogas production or power plants. While some of these sources are new (e.g., CCU in biogas production), some may emit less CO_2 in the future due to fuel diversification (electricity or hydrogen, such as in Sweden [127]) and energy savings, as also illustrated in Figure 14. Future power plants will also operate fewer hours and more intermittently compared to today's operation profiles, despite the use of more gas for this purpose. Depending on the energy system architecture, these may vary between 1500 to 4000 full load hours, which may cause a conflict with the deployment of carbon capture technologies due to their high investment costs that require long operational hours to achieve economic feasibility [80]. The low number of full-load hours appears insufficient to deploy carbon capture unless the operation of the plants changes by forcing them to operate for longer hours, resulting in increased VRES curtailment and higher fuel consumption.

The alternatives to source carbon capture are DAC or ASU for ammonia synthesis. DAC systems are approximately twice as expensive per tonne of CO_2 than, e.g., carbon capture in cement production and significantly more energy-intensive since CO_2 concentrations in the air are much lower than in concentrated CO_2 streams [23].

However, neither DAC nor ASU is bound to limited resources and thus, they could, in theory, provide enough CO_2 and N_2 to supply the fuel demands.

Therefore, there are inherent limitations on the potential of CO_2-electrofuels, the same as there are limitations on the amount of dry biomass for gasification and wet biomass for biogas production. The choice between these pathways must balance resource availability (biogenic and non-biogenic), technological maturity, and fuel costs. Figure 15 illustrates a suggested ranking of fuels built upon the results from Pathways #1 to #4.

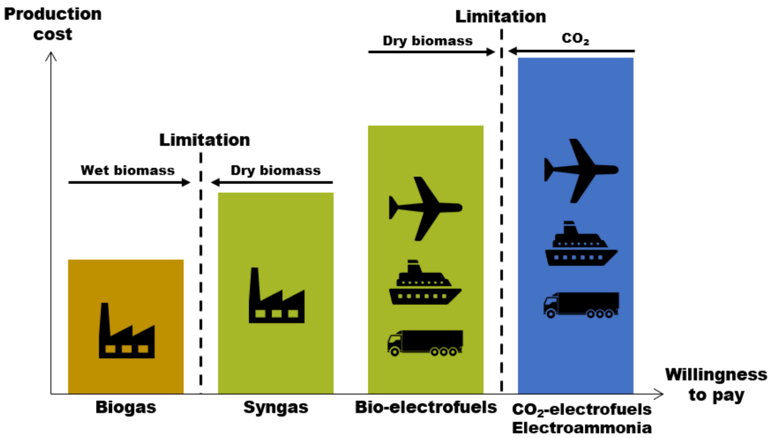

Figure 15: Fuel rankings of the four pathways defined with the added dimensions of fuel costs and resource limitations after exhausting the potential for more efficient measures as electrification.

Willingness to pay

In Chapter 3.1, the concept of Value chain was introduced and adapted for renewable fuel production pathways. The concept explained that the value of a product refers to the “total amount the buyers are willing to pay”, which includes the production cost plus a margin. The margin depends on managing the linkages between the activities and reductions in the production costs. The other part of the value chain consists of value activities, which are physical and technological.

The ranking proposed in Figure 15 can also be understood as the likely willingness to pay for fuels that originate in certain pathways (value chains) in specific applications. The expectation is that there is a higher willingness to pay for transport fuels than for fuels intended for electricity or heat production. There are two points of view in this regard. The first one refers to competitive markets, in which the alternatives for electricity or heat production from biogas or syngas have low prices, e.g. offshore wind or natural gas CCGT with CCS. In this case, it will be difficult to propose expensive hydrogenated methane (PtM) since the alternatives are significantly lower priced. Secondly, it is challenging to reduce the price of electrofuels since they are limited by the electricity cost, the most prominent cost influencer. Electrofuel prices will always be higher than the price of the electricity used for their production. In their turn, electricity prices cannot be lower than the cost of the least expensive electricity producer. Offshore wind is the best candidate here due to the high capacity factor, and the current cost estimates find it can deliver electricity at not less than 30 €/MWh, based on estimates for the North Sea towards the year 2050 [68].

The rationale proposed in Figure 15 also relates to the logic that renewable gas markets should not be considered in isolation from the electricity and heat markets but that these mutually influence each other [87]. Thus, the more expensive the gas is, the more challenging it is to integrate it on the market with other electricity producers. In other words, it will not be easy to propose electromethane for electricity production when the cost of this fuel, depending on the pathway used, varies between 60 and 120 €/MWh_{fuel} (based on the background data in Study 2). Biogas and syngas fuel production prices analysed in Study 1, and 2 were identified at 30-60 €/MWh_{fuel} for 2050 (depending on the biomass price). In comparison, the average electricity prices vary between 20 and 60 €/MWh_{el}, while district heat prices are estimated at 10 €/MWh_{th}, as found by Sorknæs et al. [87] to be the case for an integrated Danish energy system in 2050.

The price of feedstocks remains a natural influencer on the final fuel price, but the results illustrated in Figure 15 are robust. Even if the energy sector has to pay for biogas feedstock, biogas produced from manure and other wastes should still be prioritised for power (mainly) and heat production and industry, while for the remaining demands, it should be complemented by syngas from thermal gasification. Therefore, methanated biogas (PtM) is not a feasible solution because raw biogas or the derived biomethane has a higher value in the energy system in the first place.

It is difficult then to identify the role of electromethane (other than from biogas) in future energy systems with the setup proposed in this thesis. Electromethane (biogenic and non-biogenic) appears too expensive for stationary applications, while liquid electrofuels are more suitable for transport applications. However, it may find niche roles in applications ready to pay a higher price for this fuel or as a measure for dealing with biomass availability. In any case, due to the lower efficiency of such a solution, biogenic and non-biogenic electromethane can only have a limited role.

Electrofuels, in general, should remain part of future energy systems as they can offer the necessary flexibility while dealing with sustainable biomass consumption. However, the deployment of additional hydrogenated fuels besides those in the transport sector would require more VRES capacity and more fuel consumption, essentially increasing the energy system costs. Nielsen and Skov [138] demonstrated that the investment costs and the gas grids limit the potential of electromethane, and despite the balancing potential it may offer in the energy system, this makes electromethane a less significant component of renewable energy systems that already have high levels of flexibility.

Choice of end-fuels

If, in the case of renewable fuels for stationary units, it is clear that gaseous fuels as biogas, biogas-derived biomethane and syngas are preferred (in this order), the choice of end-fuels for transport is more complex. Apart from the choice between bio-electrofuels and CO_2-electrofuels, there is also the choice of end-fuels from these pathways. Pathways #3 and #4 proposed a range of fuels for various transport applications without limiting themselves to one end-fuel. It is challenging to point towards one suitable fuel for each transport sector, and in fact, multiple fuels will likely be used to supply the transport demands.

The results for heavy-duty long-distance road transport indicated that methanol is feasible for this sector due to the low production cost and biomass consumption across the scenarios investigated in Study 1 and 2. FT diesel fuel has higher production costs due to the more energy-intensive production process, despite the simplicity of storage and compatibility with existing propulsion and infrastructure. For this reason, FT diesel is not identified as a suitable option. Furthermore, compressed and liquefied methane or hydrogen may have low production costs but are less feasible for road transport when considering infrastructure requirements, storage, and vehicle costs, which is different from the recommendations in other studies [30,35] that find such fuels compatible with future decarbonisation efforts.

On the other hand, the aviation results show that FT jet fuel is, together with jet fuel from methanol-to-jet synthesis, one of the least-cost options. However, other factors may have to be considered in this sense, including the co-product fuels produced by FT synthesis, which may influence the pricing of the jet fuel, and its low operational flexibility, a potential disadvantage in renewable energy systems; factors also applicable for FT diesel in transport. In addition to these results, GTL jet fuels involving reforming from methane indicated high production costs and low energy efficiency, and unlike other findings [37], these are not be considered a large-scale solution, as syngas can be produced more efficiently from biomass or potentially even from CO_2 hydrogenation.

Shipping was analysed in detail, and the results indicated that methanol, ammonia and DME are the lowest cost alternatives for this sector for all ship types, on all utilisation rates, unless battery-electric propulsion is technically viable, in which case it is the preferred option. ICEs will likely remain a standard, at least for the deep-ocean shipping travelling long distances, while FCs will require significant cost reductions or significantly higher efficiency (15-20% higher than ICE) to replace the well-established two-stroke engines. Nevertheless, independent of the choice of the propulsion system, methanol emerged as the most feasible solution for shipping applications due to the reduced costs with the production, on-board storage and propulsion systems, but at marginal cost differences to DME and ammonia.

Infrastructure deployment in ports for bunkering and fuel favours methanol and ammonia since both commodities are traded for decades. Methanol benefits from simple storage requirements, needing only a non-pressurised steel tank. The infrastructure costs to deploy and retrofit [109] are also among the lowest among the fuels analysed, especially in the port areas where methanol is often traded in connection with the chemical industry. DME has similar storage and infrastructure requirements as ammonia in low-pressure gaseous storages, even though DME does not have the same toxicity level. However, DME would be a completely new fuel for the shipping sector without dedicated infrastructure and little knowledge of handling.

Ammonia gained more traction in shipping lately and is often identified among the preferred fuels for decarbonising this sector [30,44,139]. In general, ammonia can gain more interest in the future than CO_2-electrofuel equivalents. The abundance of N_2 feedstock can provide more flexibility towards the operation of ammonia production plants while also offering more possibilities concerning the placement of such plants. The upcoming construction of energy islands in the North Sea and Baltic Sea [140] may find ammonia a winning fuel if CO_2 sources are limited and if transporting electricity or hydrogen to the shore is too expensive, but this will require further analyses. The potential of ammonia may also be seen from the policy perspective, where this fuel may become more sought if CO_2-electrofuels from non-biogenic resources, such as cement plants or industry, are not widely recognised as renewable and contribute to the decarbonisation efforts. Nevertheless, even without the potential demand for this fuel from the transport sector, there is already a large market for ammonia that trades approximately 140 million tons per year for fertiliser production and the chemical industry. The emissions from fossil ammonia production represent more than 1% of the global CO_2 emissions[141], so there is already a significant potential for reductions from renewable ammonia.

Additional production pathways and the need for electrification

This thesis coagulated a select number of technologies and pathways for the large-scale production of renewable fuels, but these are not the only technologies that may contribute to the production of renewable fuels. The research highlighted the need for low-cost gas production, and this is one of the reasons why anaerobic digestion and thermal gasification are credited central roles for gas production. Thermal gasification is also an efficient and flexible method for producing various liquid fuels, while CO_2 hydrogenation can supplement it to reduce the pressure on biomass resources. However, other biomass conversion technologies as HTL, pyrolysis and hydro-processing can play a role in the energy system, but one should keep in mind these pathways produce primarily liquid fuels.

HTL has good potential in connection with upgrading bio-oil in existing refineries, but still requires research and development before it can go into the demonstration phase. A bottleneck may represent the feedstock availability since it uses similar feedstocks as anaerobic digestion and thermal gasification. From the system perspective, this may make the prioritisation of technologies complicated since gas demands will likely remain high, while methanol production via biomass hydrogenation has high efficiency and flexible operation potential. However, HTL may gain more traction in the case of biomass diversification with algae [142,143] or different types of wastes [144]. Fast and catalytic pyrolysis have a mixed output of bio-oil, syngas and biochar so that they may be geographically combined with gasification plants as the feedstocks used are similar. Since this technology's prime attractiveness is the production of drop-in biofuels, it may be more challenging to integrate it into a system with an already considerable share of non-hydrogenated gas in stationary units. Not least, hydro-processing as HEFA should continue contributing to the production of aviation fuels, but this pathway will always be limited to the available feedstock, despite the technology's maturity, so its role can only be limited. In addition to these pathways, others should be mentioned, here including trans-esterification and fermentation. Driven by the principle of energy efficiency first, it is regarded that such pathways are inefficient compared to the alternatives that use similar feedstock, especially in the case of straw feedstock.

The research in this thesis focused on identifying the feasible renewable fuels pathways that can be part of future sustainable energy systems. Although the role of these fuels is critical for complete decarbonisation, in the system perspective, direct and battery electrification should be prioritized before any type of renewable fuel. The efficient use of resources and renewable electricity is also a resource and a requirement for future energy systems. It would be impossible to discuss the feasibility of renewable fuels in renewable energy systems if aspects such as energy efficiency and electrification were not considered in the analysis. The science of renewable fuels must be understood as a complement to electrification, not as a competitive technology.

9 CONCLUSION

The research conducted in this thesis deals with the feasibility of renewable fuel pathways from an energy system perspective. It is premised on the idea that renewable fuels will play an essential role in the future, but there is little convergence towards a coordinated set of solutions across all energy system sectors requiring renewable fuels. The following research question arose based on the need for more clarity regarding the suitability of the various solutions available:

Which are the feasible renewable fuel pathways that integrate with sustainable energy systems?

In response to this question, the thesis was structured as a feasibility study built around a collection of three peer-reviewed journal articles. The three studies inquire into the design of future renewable fuel solutions using different perspectives and case studies. Studies 1 and 2 apply a national level top-down approach based on energy system analyses for Denmark and Europe. Study 3 applies a bottom-up approach based on a techno-economic analysis and total cost of ownership from a global perspective for the shipping sector. Therefore, the combination of methods generates an improved understanding of both ends of renewable fuel pathways. The energy system analysis approach is comprehensive in resource consumption and fuel conversion, but it loses detail regarding storage and utilisation. Meanwhile, the techno-economic analysis offers more detail on storage and utilisation, but it cannot represent the hourly operation and synergies with other energy sectors. By combining these approaches in the context of a long-term view, the research investigated relevant technical alternatives considering their economic, environmental, and social aspects.

First, it was identified that biogas could be beneficial for the energy system when used in stationary units for power and heat production or industry. Raw biogas or biogas-derived biomethane can ensure lower dry biomass consumption for gas production purposes, reflecting reduced energy system costs. Despite these benefits, biogas plants remain primarily a method for handling waste and will likely be limited by the types of feedstock they use. Future gas demands for power generation will remain high due to the need to balance increasingly significant wind and solar generation capacities. To supply this demand, syngas from the thermal gasification of biomass can complement biogas in the same energy sectors. Due to its dependence on more expensive feedstocks, such as solid agricultural residues and woody biomass, syngas is inherently more expensive than biogas, yet it is necessary to balance the energy system. Both biogas and syngas can be used directly in any combustion unit, which remains the most cost- and energy-efficient way of utilising these resources. While biomethane can be purified from biogas at a minimal cost, syngas methanation comes with a higher price and energy penalty.

Syngas from thermal gasification can also be used to produce bio-electrofuels for use in transport; hence, this technology's dual role requires careful balancing against factors such as biomass availability, the potential for electrification, transport and electricity demands, technology readiness level and the availability of other fuels. Bio-electrofuels can enable the production of lower-cost fuels for the transport sector than the fuels produced from CO_2 hydrogenation. CO_2-electrofuels are more expensive than bio-electrofuels since they require additional electrolysis capacity, hydrogen storage, and VRES. Energy systems dominated by CO_2-electrofuels are also less efficient as they require more power plant operation, thereby using more fuels. Despite a potentially more significant fuel consumption in power plants, CO_2-electrofuels may still be limited by future flexible power plant operation.

CO_2-electrofuels will, however, remain necessary to some degree as bio-electrofuels cannot supply all transport-related demands. DAC may replace point-source CC, but this may further reduce energy system efficiency due to the energy-intensive nature of the DAC process. The production of ammonia can also supplement CO_2-electrofuels to add the advantage of operational flexibility due to the abundance of N_2, which also opens further possibilities for the placement of ammonia plants.

Methanol and methanol derivatives like DME are suitable for road transport and shipping, primarily due to their low production cost (as bio-electrofuel or CO_2-electrofuel), but also due to the low costs of the related storage, infrastructure and propulsion systems. Methanol-to-jet-fuel synthesis shows similar production costs to FT jet fuel, a more established synthesis, but the flexibility of methanol synthesis may be an advantage if it can reduce the need for expensive hydrogen storage. Alongside the potential of methanol, the analysis of the shipping sector identified marginally higher costs for DME and ammonia in all types of ships and utilisation rates. While production costs are similar, cost differences arise from the practicality of storage and propulsion systems compared to those using methanol. Although ammonia does not emit CO_2 (another reason for its attractiveness), it still requires significant post-combustion treatment to tackle the global warming potential of NO_x and N_2O. In all the cases, and for all transport sectors, the results indicated that the most feasible renewable fuels remain those that also come with low storage costs. These are methanol, any of the jet fuels or low-pressure compressed gaseous fuels as ammonia and DME.

Although presenting lower costs and better energy efficiency than the alternatives, all four renewable fuels mentioned above will continue to have higher production costs than their fossil counterparts and electrification, even with significant investment cost reductions. Hydrogenating a part of the future fuel demands is necessary to deal with biomass limitations and increase the energy system flexibility. Therefore, future renewable fuel production must consider the correct allocation of resources and fuels in future electricity, gas, liquid and heating markets—such an allocation links with the willingness to pay and the value of a product. Biogas, complemented by syngas, should supply future gas demands, while bio-electrofuels should supply transport demands, complemented by CO_2-electrofuels and electroammonia. Overall, these can be considered generalised guidelines that may be applicable to any energy system with high shares of renewable energy as they are based on value creation, energy efficiency and Smart Energy Systems.

Finally, while this thesis lacks a complete end-to-end assessment of the production pathways for renewable fuels in road transport and aviation that would confirm the energy system analysis results, the shipping sector analysis provides valuable insight into the limitations of some fuel-propulsion combinations. Industry demands did not receive the same level of detail as transport, under the assumption that biogas, syngas or biomethane would meet industrial gas demands. However, higher temporal resolutions and country-specific demand analyses may reveal more industry-specific demands.

10 FUTURE WORK

There are many opportunities for further research that can build on the results of this thesis. In general, these should focus on the feasibility of renewable fuels in relation to the potential for electrification and energy efficiency. In addition, there is also a need for continued effort in technology development and demonstration. Some of the most interesting avenues for future research include:

- **Primary conversion of straw**

Straw is a valuable resource, with a high share of the total biomass resources, especially in countries like Denmark. Straw can be processed in biogas plants and gasifiers, while the straw-rich digestate can also be gasified. However, it is still unclear which method is the most valuable and energy-efficient, so further research is necessary, preferably from an energy system perspective.

- **HTL, pyrolysis and hydro-processing**

As described in Chapter 5.2, multiple biomass conversion technologies exist. This research identified biogas plants and gasifiers suitable for the large-scale deployment of renewable fuels, but the potential contribution of HTL, pyrolysis or hydro-processing should not be ignored. Further energy system analysis should clarify the potential roles of these technologies. The primary outputs of these conversion technologies are liquid fuels, so a potentially valuable contribution would be towards developing drop-in replacements for fossil fuels in aviation– one of the transport sectors in which these fuels may have the highest value.

- **Future transport demands**

A large part of the future demands for renewable fuels relates to transport. However, with the accelerated deployment of electrification, what is challenging to electrify today may likely be easier to electrify in few years; this will also impact the demands for renewable fuels. Continued assessment of electrification potential is necessary to ensure that electrification is prioritized over renewable fuels. A similar total cost of ownership analysis to that performed for shipping in Study 3 should also be performed for road transport.

- **Renewable fuels for industry and tertiary sectors**

Much like the detailed assessment for road transport, a similar analysis must be performed for industry, which also has a high potential for electrification and energy savings. Such an analysis is part of the Horizon 2020 sEEnergies project [145] that aims to quantify the energy efficiency potential in this sector in a detailed manner.

- **Demonstration of the thermal gasification of biomass**

Thermal gasification is identified as a critical technology in this thesis. However, to date, there has been a lack of development and demonstration projects to push the technology forward and address the uncertainty concerning efficiency and costs. Biogas and CO_2-electrofuel development may lead in this sense, so more funding and demonstration efforts are required for all gasifier designs, with and without hydrogenation, to ensure more certainty regarding costs and efficiencies.

- **Liquid electrofuel production plants**

Liquid electrofuel plants using biogenic and non-biogenic carbon require more demonstration projects. Two key aspects of these technologies have been identified throughout the research that require further knowledge. The first is the flexibility of the entire production cycle, including methanol synthesis, which is the only liquid fuel synthesis that may operate flexibly, thus reducing the need for more expensive hydrogen storage. The second is the production of fuels for aviation use, which may remain one of the few transport sectors requiring liquid fuels in high electrification scenarios.

- **Energy islands and renewable fuels**

The emergence of energy island hubs for large offshore electricity production calls for detailed modelling on the role of these islands [140]. Should electricity be used on-site for the production of electroammonia, or should the hydrogen or electricity be transported on-land to produce renewable hydrocarbons?

- **Hybrid and electric shipping and aviation**

The research in Study 3 found strong potential for electrification in large ferries travelling for up to 12-18 hours, but the study did not examine the potential of hybrid shipping in general, which may be a method for dealing with the high cost of fuels. Similarly, aviation may also benefit from hybridisation.

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SUPPLEMENTARY MATERIAL FOR STUDY 3

Supplementary material for "Techno-economic assessment of advanced fuels and propulsion systems in future fossil-free ships."

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Appendix A

1) Biofuels

The fuels included in this category are biomethanol, bioDME, biodiesel, bioLMG, bioLBG and HVO.

The production pathways for the first four fuels start with thermal gasification of biomass. Thermal gasification is the process that extracts the energy from biomass in a gaseous product called syngas. The gasification can be done with different types of gasifiers that can be grouped by the type of gasification agent used (air, oxygen or steam) or the design of the reactor (fixed bed, circulating fluidised bed and entrained flow). Some types of gasification reactors fit better than others, depending on the end-fuel produced. In this analysis, we used cost data from the Danish Energy Agency [1] for a fixed bed gasifier based on steam gasification. The necessary feedstock depends on the type of gasifier and the desired end product, in general, dry biomass such as wood chips, wood pellets, or straw [1] but also the lignocellulose residues from anaerobic digestion from biogas plants. The syngas produced in the gasification process is cleaned and tuned to the right composition using the RWGS reaction to balance the H_2/CO ratio. The gas is then run through a chemical synthesis process to obtain biomethanol, used as an end-fuel or dehydrated to obtain bioDME. The dehydration process includes 2% energy losses, achieving a process efficiency of 57% (biomass to bioDME), while we calculate the process efficiency for biomass to biomethanol at 60% based on the data found in [1]. The electricity consumption used to obtain these fuels is negligible and not included in the fuel cost calculations [1].

Biodiesel production requires the Fischer-Tropsch (FT) synthesis and upgrade, which produces a range of end-fuels as kerosene, diesel, naphtha or gasoline [2]. The FT synthesis is designed to increase the yield of the heaviest hydrocarbons, despite a trade-off between yield and production rate. In any case, the distribution of products is determined by the severity of hydrocracking [2]. The hydrocracker unit is a standard refinery unit that can shift the distribution of products based on the desired end product. Since it is difficult to determine the production efficiency of a single product, e.g. biodiesel, we assume the other end products from this process are equally valuable, and for simplicity, all the FT fuels represent biodiesel. The process efficiency for the FT products is estimated at 52% [2], but, again, one must keep in mind that not all resulting fuels are biodiesel.

BioLMG and bioLBG are mostly the same fuel, but they differ in the production process. The first one uses biomass gasification and RGWS reaction to achieve the right H_2/CO stoichiometry for the syngas, which is then processed in a reactor to produce methane. The process efficiency to obtain bioLMG is calculated at 61% based on [1]. BioLBG uses a different feedstock, a combination of animal manure, organic waste from food processing, straw or other energy crops, fed into an anaerobic digester. Biogas plants process the biodegradable feedstock to produce a methane-rich gas that can be upgraded to methane by removing the CO_2 and other impurities. The biogas typically contains 50-75% methane that can be liquefied into bioLBG prior to the use and stored at low temperatures. The process efficiency of biogas to bioLBG is 94% (since the calorific value of wet biomass inputs, as manure, is not relevant), including an electricity consumption of 4% of the biogas output, according to [1].

2) Bio-electrofuels

The fuels included in this category are: e-biomethanol, e-bioDME, e-biodiesel, e-bioLMG and e-bioLBG.

Apart from the hydrogenation technologies (described in Section 2.1 of the manuscript), the gasifiers and biogas plants are the same as in the case of the biofuels, but without the need for RGWS reaction, as electrolytic hydrogen is used to balance the stoichiometry. There is, however, the need for a chemical synthesis reactor, for the production of e-biomethanol. The same e-biomethanol can be used directly as end-fuel or dehydrated to DME. Concerning the flexible operation of electrolysis, the chemical synthesis can only be operated at a continuous rate in order not to loose efficiency [1]. The input-output efficiencies of the two pathways are 56% and 54% respectively.

For the production of e-biodiesel, FT pathway is used, with the same considerations as in the case of biodiesel. In this analysis, the process efficiency is calculated at 51% (input to output) [2]. As in the case of the biofuel pathway, we assume that all FT fuels represent e-biodiesel, for comparability with the other pathways.

The production of LMG requires a catalytic methanation reactor. In this reactor, syngas from the gasification process and hydrogen are combined to produce methane, which then is liquefied with an overall efficiency of 55%. For LBG, the CO_2 in the biogas is enhanced with hydrogen in a methanation reactor. The resulting methane is then liquefied, resulting in a total process efficiency of 64%. As in the case of chemical and FT syntheses, methanation requires a steady-state operation, due to the high operating temperatures.

3) Electrofuels

The following types of fuels can be produced as electrofuels: e-methanol, e-DME, e-diesel, e-LMG, and ammonia.

The production pathway differs from bio-electrofuels, where the gasifier or the anaerobic biogas plant is replaced with carbon capture technology. In this case, the carbon can come from Direct Air Capture (DAC) or high concentrated carbon sources as power production, industry or fuel upgrading. It is difficult to establish a single cost for carbon capture, as this varies significantly in the literature. Brynolf et al. [3] suggests that short to mid-term costs can start from as little as 20 €/tCO_2 [3] in the case of carbon captured from ethanol production to 170 €/tCO_2 for capture in coal power plants. However, it is unclear if these should be interpreted as investment costs or actual costs of the carbon captured. To build on the uncertainty, Fasihi et al. [4] suggest that air carbon capture can have an investment cost as little as 189 €/tCO_2 in 2030 in their base case and 338 €/tCO_2 in their conservative case, but they also provide the current air carbon capture cost at 730 €/tCO_2 in 2020. Lower cost carbon sources will be used first, but ultimately are dependent on the availability of the resource. We assume that a broader range of carbon capture sources will be necessary. Therefore we use an investment cost of 400 €/tCO_2 in our base case, which covers higher priced point-source carbon capture as well as potentially lower-cost air carbon capture. Fasihi et al. [4] also estimate that low-temperature DAC requires both electricity (225 kWh/tCO_2) and heat (1500 kWh/tCO_2) in opposition to the high-temperature DAC that uses only electricity, but in larger quantities. The assumption here is that a fuel production plant releases large amounts of heat, (mostly high-temperature heat) from electrolysis and fuel synthesis which can be integrated with carbon capture. We use Fasihi et al. [4] assumption on electricity consumption for DAC, while for carbon capture at point sources we estimated half of that electricity, as described by Brynolf et al. [3].

Chemical synthesis reactors are used to produce e-methanol, and e-DME, whereas an FT synthesis reactor is used to produce diesel. The process efficiencies come in close range to bio-electrofuels, with 52% electricity to e-methanol and 50% electricity to e-DME. E-diesel production via FT synthesis follows the same assumptions as in the case of the equivalent biofuel and bio-electrofuel pathways, with process efficiencies of 45%. E-LMG is produced with the help of a catalytic methanation reactor, where after liquefaction the electricity to LMG efficiency reaches 52%.

Another fuel with significant potential in the maritime sector is ammonia (NH_3). Ammonia is currently used in the production of fertilisers and produced from fossil fuels. Renewable ammonia has a similar production principle as electrofuels, but instead of carbon, nitrogen is combined with hydrogen. An Air Separation Unit (ASU) captures the nitrogen. The only commercially available technology for capturing nitrogen in large-scale applications is the cryogenic air distillation. The advantage of this technology is that it can also capture and process other gases, like oxygen and argon, including liquefying the oxygen from the electrolysis plant. This feature can contribute to a better plant economy [5]; however, not taken into account in this study. At high temperature and pressures, nitrogen is combined with hydrogen for ammonia synthesis in the Haber-Bosch reaction. The reaction is exothermic and generally optimised for continuous production, but load shifting can be achieved. The ammonia synthesis together with the ASU consumes 0.64 MWh/tNH_3 of electricity, as described in [5].

4) Hydrogen fuel

The production of liquified hydrogen (LH_2) is a more straightforward process than producing electrofuels because fewer technologies are involved. In the configuration used in this analysis, the hydrogen produced by electrolysis is liquefied for the use on-board ships. Hydrogen liquefaction is an energy-demanding process associated with a high capital cost [6]. Designing liquefaction plants includes trade-offs between capital cost and electricity consumption, and the cost of liquefaction can, therefore, vary between plants. Existing plants have a capital cost between 1,100-1,400 €/kW, while the power requirement is in the range of 10-14 kWh/tonne H_2 [6]. In this analysis, we kept the high capital cost but assumed a power consumption of 0.09 kWh_{el}/kWh_{LH2} [6]. LH_2 is stored in insulated cryogenic storage tanks which are supplied to the market in different sizes, but existing large LH_2 storage is mainly used in connection to the spacecraft industry. Additional losses for transportation, distribution and refuelling of hydrogen were not accounted for in the fuel cost calculations to keep a similar methodology with the other fuel production options.

Appendix B

1) Internal combustion engines

The fossil fuel Marine Gas Oil (MGO) engines can be converted to combust methanol with similar efficiencies, or new ones can be built with similar or higher fuel efficiencies [7]. Methanol does not have the same viscosity as MGO, so when retrofitting existing engines special attention must be given to viscosity related issues such as preventing leaks in seals. These retrofitted engines also need a pilot fuel for ignition or ignition enhancer, but at the same time do not need some components MGO engines need, as fuel boilers and separators [7]. The cost of a retrofitted methanol engine is estimated to 270 €/kW by Marquéz and Andersson [7], but the same authors estimate that dedicated methanol ICE may have a lower cost in the future. There is a wide range of potential costs for marine ICEs, and it is difficult to assess if economies of scale can be achieved [8–10]. It is, however, clear that methanol engines should be more expensive than MGO engines due to the additional fuel processing system, estimated at an extra 20 $/kW by Taljegard et al. [9]. Considering available data, we identified costs provided in [10] appropriate for diesel engines (240 and 460 €/kW for four-stroke medium-speed engines and two-stroke diesel engines), while adding 10% additional cost for methanol engines.

Gas engines are commercially proven technologies used on-board of LNG tankers for more than 20 years. In 2017, there were at least 117 LNG fuelled vessels (except LNG tankers) in operation [11]. LNG is an Otto fuel and needs ignition to start the combustion. Several types of engines exist, split into three categories: lean burn spark ignition, low-pressure dual fuel and high-pressure dual fuel. For the latter two a pilot fuel, typically diesel, is used as an igniter to start the combustion. The first two categories are the most common, but these suffer from a larger methane slip [12]. With the use of methane as fuel, there is a risk of leakage during the fuel life cycle, for example, during fuel storage and bunkering operations [13]. This is a significant issue, as methane is a potent GHG which may limit the deployment of this technology on a larger scale if the issue is not solved. Existing MGO/HFO (fossil Heavy Fuel Oil) engines can be converted to using liquid methane fuels, but the retrofit costs are significantly higher than for retrofitting to methanol [7]. Building new LMG/LBG engine setups are considered more costly than methanol ICE [8,9], and for consistency, we selected a cost of 470 and 700 €/kW for four-stroke and two-stroke engines as provided by Baldi et al. [10].

Hydrogen is also an Otto fuel and can be used in spark-ignited as well as different types of dual-fuel engines [14]. A hydrogen engine for marine purposes is, for example, developed in the H2020 project HyMethShip [15]. Extra safety measures are needed when using hydrogen, and the risk of hydrogen embrittlement needs to be considered [14]. The same cost as for LMG/LBG engines is considered.

DME has a high cetane number and excellent combustion properties, but ICEs running on DME require specially adapted components, such as the fuel pump and injectors [16]. This is not expected to affect the efficiency of such engines but may affect the cost compared to a diesel engine, so the same cost as for methanol engine is assumed [17]. To the authors' knowledge, no ships have been equipped with these types of engines yet, but manufacturers are ready to produce such engines if demand exists [17].

Ammonia ICE represents the more novel solution put forward by the industry [18] as an alternative option to carbon and hydrogen-based fuels. Ammonia engines are not commercialised yet, but engine manufacturers as MAN claim the technology is readily available [19]. In a partnership with Samsung Heavy Industry and Lloyds Register, MAN aims to develop low-speed ICE using ammonia that should be ready before 2030 for commercialisation on large-scale [20]. Ammonia can work in engine designs similar to DME engines, but none of the fuels has been tested so far in any commercial shipping applications. Existing research [21,22] shows that ammonia works best in combination with hydrogen as their flame velocity and minimum ignition energy are very different, so mixing the fuels can reach a compromise. This fuel mixture is approximately 70% ammonia and 30% hydrogen (based on energy content) [22], which is also what was considered in this study. Ammonia engines also need additional components, as a cracker to partially split the ammonia to hydrogen in the right mixture, and an evaporator for the boil-off ammonia. In some cases a tank heater should be used to compensate for the pressure drop in the ammonia tank. Low-flash injection engines (as needed for ammonia and DME) are estimated to 530 €/kW [23], whilst de Vries [22] estimates a cost for a two-stroke low speed ammonia engine at 400 €/kW. In lack of more specific data for engines powered by these fuels, we judged reasonable to consider these engines to position mid-way between methanol and LMG/LBG engines.

2) Fuel cells

The low temperature proton exchange membrane fuel cell (LT PEMFC) technology has seen significant development in the past years and have already been successfully demonstrated in small capacities and has a relatively lower cost in comparison with other technologies [24,25]. The LT PEMFC operate at 65-85°C with tolerance to load changes and have an electrical efficiency of 50-60% with high power density. On the downside, at low operating temperatures, the use of platinum is required to catalyse the reaction, which also requires high purity hydrogen, due to the danger of poisoning with carbon monoxide or sulphur. Because of this limitation, LT PEMFC requires extensive fuel processing if used with hydrocarbons, which influences the efficiency, cost and transient operation. Fuel reforming is widely applied to convert methanol and methane into syngas, a mixture of carbon oxides and hydrogen [24]. Fuel reforming may take place on board of the ship, also assumed in this analysis. Besides this process, others may be required depending on the fuel used, such as a hydrogen purification system or evaporators. High-temperature proton exchange membrane fuel cells

(HT PEMFC) is a less mature technology than the LT PEMFC but has the benefit of being more tolerant of CO poisoning. This technology eliminates the need for using expensive fuel reformers and clean up reactors, while its higher operational temperature (200°C) allows for the heat to be recovered and used in the internal systems of the ship [25].

SOFC operate at high temperatures between 600-700°C and are compatible with carbon or nitrogen-based fuels as the fuel reforming process takes place within the fuel cell. SOFC have the same electrical efficiency as PEMFC, but if heat recovery can be achieved, then the overall efficiency can increase to 85% [25]. On the downside, SOFC have a lower tolerance to loads changes than PEMFC so it is common for these to be coupled with battery systems that can cope with the typical operation of ships, including accelerations and decelerations, port manoeuvres and slow start-up times, all more stringent demands than in the case of PEMFC. Such hybrid propulsion has not been built so far, except for several small scale demonstration projects [25].

Capital cost is another essential element in the choice of FC propulsion systems. At the current production volume, the cost of FC systems is still often estimated in the literature to be >1000 €/kWe [8,9,24], but according to some estimates, PEMFC system costs tend to go lower, with de Vries [22] suggesting 800 €/kWe, Baldi et al. [10] proposing 730 €/kWe, while Afif et al. [26] estimates a cost of ~630 €/kWe. SOFC is estimated with significantly costs differences, from 5000 €/kWe by de Vries et al. [22], to 2650 €/kWe for 2030 by Horvath et al. [8], to only 1280 €/kWe by Baldi at al. [10]. To this cost, one may need to add the cost of fuel reforming (cracking), evaporator, gearbox and electrical system, often not specified in the literature. In the context of this analysis, and with the technical limitations of FC, it is assumed that all fuels and propulsion systems analysed operate with both LT and HT PEMFC. This assumption is flexible, where if SOFC eventually proves technological maturity and suitability for maritime use, then the potential higher cost of SOFC may be offset by the reformer cost and PEM, bringing the two technologies at similar costs.

4) Fuel storage

Methanol requires the least modifications of tanks and auxiliary units, compared to the other fuels analysed in this paper. For instance, existing tanks can be retrofitted with the addition of a methanol specific coating; therefore, low investment costs are assigned to this technology [7]. A drawback of methanol is the lower energy density that is less than half of MGO. Methanol is not classified as a marine pollutant and can, therefore, be carried in tanks next to the hull, eliminating the issue of lost cargo space [27]. However, methanol is still a toxic substance with potentially adverse effects on the marine environment. In terms of costs, existing bunkering barges are estimated to cost 1.5 M€/barge to reconverted to methanol, while building a new methanol tank with 20,000 m3 capacity can be done at the cost of 57 €/MWh. This cost is approximately 7-10 times lower than building a similarly sized bunkering facility for LNG, LMG or LBG [15].

DME and ammonia require similar storage conditions as LPG (liquefied petroleum gas) at pressures between 10 and 20 bars depending on the ambient temperature [16,22]. Compared to diesel, the fuel density and viscosity are lower so fuel leakages may become an issue, especially for ammonia, which is classified as a toxic substance. Despite its toxicity, ammonia is a global market commodity, transported by ships, so consistent knowledge exists on handling it. The volumetric density of DME is almost half of MGO, while the one of ammonia is about a third of MGO, indicating that both fuels demand additional space for the fuel tanks.

LMG and LBG also struggle with low volumetric density, with 60% of the energy density of MGO. The storage tanks need significant insulation, and the evaporated gas needs to be removed to reduce pressure [11]. Hydrogen has even stricter storage requirements when stored as a liquid, which is preferred over gas cylinders as it can provide a good trade-off between gravimetric and volumetric energy density. Even in liquid form, hydrogen still has a volumetric density of 4-5 times lower than MGO. In order to liquefy hydrogen, it must be cooled down and stored at temperatures of -253°C. One of the challenges of storing hydrogen at such low temperatures is the thermal insulation needed to reduce the boil-off [28].

The disadvantages of using battery-electric (BE) systems mainly relate to the high capital cost of batteries, but this issue is partially mitigated with the steep cost reduction in battery cell costs [29,30]. Shipping battery systems are evaluated at higher costs than automotive battery packs due to the additional costs with a slightly differ cell cost, insulation and cooling equipment as well as fire safety equipment, all estimated more strict than road vehicles [31]. As such, DNV GL [32] suggests a current cost of 245 €/kWh, MAN a cost of 225 €/kWh [31], while Baldi et al. [10] propose 260 €/kWh. Towards 2030, Alnes et al. [29] find a wide range of potential costs from 200 to 600 €/kWh based on various predictions while another report on zero-carbon fuels [23] proposes 160 €/kWh. Battery pack costs for automotive are estimated at 180-225 €/kWh today [30] and seem to decrease well below the 100€/kWh mark by 2030 [31]; hence we estimated a conservative 250 €/kWh for the battery pack in our base case scenario.

Appendix C

1) Propulsion and fuel storage cost

The analysis of the capital costs for propulsion systems and fuel storage for all four categories of ships reveals that ICEs always have a lower investment cost compared to FCs by a magnitude of 3 to 6 for all voyage lengths. The distance travelled influences the capital costs once the ship needs to travel longer distances, this being the most evident for LH_2 and BE ships, but has little influence for the other fuels (Figure C1). Among the ICEs, diesel and methanol engines have the lowest capital costs due to the reduced complexity of the engines as well as low-cost storage options. The ammonia propulsion system is more expensive due to its dual fuel injection system, the requirement for an ammonia cracker to produce hydrogen and the ammonia evaporation system. LMG and hydrogen ICEs also have high investment costs, but hydrogen proves as a more expensive alternative due to the high-priced fuel storage tanks. Figure C1 also shows the high upfront cost of batteries making BE propulsion systems about ten times more costly than the average cost of the ICE option for large ferries.

Base case		Large ferry			General cargo			Bulk carrier			Container		
Propulsion	Fuel	Short	Medium	Long	Short	Medium	Long	Short	Medium	Long	Short	Medium	Long
ICE	Diesel	0,2	0,2	0,2	0,1	0,1	0,1	0,6	0,6	0,6	2,0	2,2	2,3
	Methanol	0,2	0,2	0,2	0,1	0,1	0,2	0,6	0,7	0,7	2,3	2,5	2,7
	DME	0,4	0,4	0,4	0,2	0,3	0,3	0,9	1,0	1,2	3,3	3,8	4,2
	LMG,LBG	0,6	0,6	0,6	0,5	0,6	0,7	1,6	2,0	2,5	5,8	7,5	9,2
	Ammonia	0,6	0,6	0,6	0,3	0,4	0,4	1,2	1,3	1,3	4,3	4,6	4,8
	LH2	0,6	0,6	0,7	0,6	0,8	1,0	2,0	2,8	3,6	7,2	10,1	13,1
FC	LH2	2,0	2,0	2,0	1,4	1,7	2,0	3,4	4,1	4,7	12,5	15,2	17,9
	Methanol	2,8	2,8	2,8	1,6	1,6	1,6	3,9	3,9	4,0	14,0	14,2	14,4
	LMG, LBG	3,0	3,0	3,0	1,8	2,0	2,2	4,4	4,8	5,2	16,1	17,6	19,1
	Ammonia	3,0	3,0	3,0	1,7	1,7	1,7	4,1	4,1	4,2	14,8	15,0	15,3
BE	BE	2,2	4,1	6,1									

Figure C1: Capital costs (propulsion and fuel storage costs) in M€ for the four types of ships in all voyage lengths in the base case

2) Cost sensitivity

The ships using FC propulsion have higher total capital costs than ICE in all cases, an expected result considering the significantly higher cost of the technology. According to van Biert et al. [24], this cost may decrease to 45-250 €/kWe or to as low as 35 €/kWe, which is on a magnitude of 3-20 times lower than the PEMFC cost used in this analysis (730 €/kWe). The industry sees these costs as potentially achievable once the production volumes increase, but if the projected cost of electrolysers is taken as a proxy, virtually similar technology using similar materials and parts, such costs do not go lower than 600 €/kWe in 2030 or 400 €/kWe in 2050 for PEM [1]. Stationary systems using PEMFC technology are estimated at 1100 €/kWe by 2030 and to 800 €/kWe by the year 2050 with significant cost uncertainties [33] and despite having different end-uses, the significant cost difference to automotive fuel cells is difficult to explain. To illustrate the effects of lower investment cost for PEMFC, we performed a sensitivity analysis where the PEMFC cost is reduced to 400 €/kWe, the same cost as the lowest cost electrolysis technology. A similar cost reduction is applied to BE ferries, by reducing the cost of battery-systems to 150 €/kWh, based on the findings in Appendix B. The results of this sensitivity analysis are presented in Figure C2.

Low FC and BE cost		Large ferry			General cargo			Bulk carrier			Container		
Propulsion	Fuel	Short	Medium	Long	Short	Medium	Long	Short	Medium	Long	Short	Medium	Long
ICE	Diesel	0,2	0,2	0,2	0,1	0,1	0,1	0,6	0,6	0,6	2,6	2,8	2,9
	Methanol	0,2	0,2	0,2	0,1	0,1	0,2	0,6	0,7	0,7	2,7	2,9	3,1
	DME	0,4	0,4	0,4	0,2	0,2	0,3	0,8	0,9	1,1	3,0	3,4	3,9
	LMG,LBG	0,6	0,6	0,6	0,5	0,6	0,7	1,6	2,0	2,5	5,3	7,0	8,6
	Ammonia	0,6	0,6	0,6	0,3	0,4	0,4	1,2	1,3	1,3	4,3	4,6	4,8
	LH2	0,6	0,6	0,7	0,6	0,8	1,0	2,0	2,8	3,6	6,6	9,6	12,6
FC	LH2	1,4	1,5	1,5	1,0	1,3	1,5	2,6	3,3	4,0	9,6	12,3	15,1
	Methanol	1,3	1,3	1,3	0,7	0,7	0,7	1,8	1,8	1,9	6,4	6,6	6,7
	LMG, LBG	1,4	1,5	1,5	0,9	1,1	1,2	2,3	2,7	3,1	8,4	9,9	11,5
	Ammonia	1,4	1,4	1,4	0,8	0,8	0,8	2,0	2,0	2,1	7,1	7,4	7,6
BE	BE	1,5	2,8	4,1									

Figure C2: Capital costs (propulsion and fuel storage costs) in M€ for the four types of ships in all voyage lengths in an improved FC scenario

The lower cost-efficient FC propulsion system reduces the total investment costs, but FCs remain 2-3 times more expensive than ICE on average. BE as well as liquefied methane and hydrogen propelled vessels remain the most capital-intensive technologies. The ranking between the propulsion systems does not change, but the cost reductions for FC systems does change the results over ICEs in the TCO analysis as found in Section 4.2 as well as in Appendix D.

Appendix D – Sensitivity analyses

1) High electricity price

Off-shore wind increase by 50% to 49 €/MWh (from 33 €/MWh).

Fuels	Short			Medium			Long		
	ICE	FC	BE	ICE	FC	BE	ICE	FC	BE
MGO	0,9			1,70			2,45		
Biomethanol	2,0	4,2		3,9	5,7		5,7	7,2	
BioDME	2,3			4,2			6,2		
Biodiesel	2,7			5,2			7,6		
BioLMG	3,0	4,9		5,4	6,8		7,8	8,7	
BioLBG	2,8	4,8		5,1	6,6		7,4	8,4	
HVO	2,4			4,6			6,8		
E-biomethanol	3,0	5,0		5,7	7,2		8,5	9,4	
E-bioDME	3,3			6,2			9,1		
E-biodiesel	3,7			7,2			10,7		
E-bioLMG	4,0	5,7		7,5	8,5		11,0	11,3	
E-bioLBG	3,9	5,6		7,2	8,2		10,5	10,9	
E-methanol	4,1	5,9		8,0	9,0		12,0	12,2	
E-DME	4,5			8,6			12,7		
E-diesel	5,2			10,3			15,3		
E-LMG	5,1	6,6		9,6	10,2		14,1	13,8	
Ammonia	4,5	6,1		8,4	9,2		12,4	12,4	
LH_2	5,4	5,9		10,3	9,8		15,3	13,7	
Electricity			3,1			6,0			9,0

Figure D3: The TCO for large ferries in the scenario with high electricity price

Fuels	Short		Medium		Long	
	ICE	FC	ICE	FC	ICE	FC
MGO	1,3		1,5		1,8	
Biomethanol	3,0	3,8	3,7	4,4	4,6	5,1
BioDME	3,3		4,0		4,9	
Biodiesel	4,0		4,8		5,8	
BioLMG	4,2	4,8	5,1	5,6	6,2	6,6
BioLBG	4,0	4,6	4,8	5,4	5,9	6,4
HVO	3,6		4,3		5,2	
E-biomethanol	4,4	5,0	5,4	5,8	6,7	6,8
E-bioDME	4,8		5,8		7,1	
E-biodiesel	5,6		6,7		8,1	
E-bioLMG	5,8	6,1	7,1	7,2	8,7	8,6
E-bioLBG	5,6	5,9	6,8	7,0	8,3	8,3
E-methanol	6,2	6,4	7,6	7,5	9,3	8,9
E-DME	6,6		8,0		9,8	
E-diesel	8,0		9,5		11,6	
E-LMG	7,5	7,4	9,0	8,8	11,1	10,5
Ammonia	6,5	6,6	7,8	7,7	9,7	9,1
LH_2	8,1	7,4	10,1	9,1	12,7	11,2

Figure D4: The TCO for general cargo in the scenario with high electricity price.

Fuels	Short		Medium		Long	
	ICE	FC	ICE	FC	ICE	FC
MGO	3,2		3,7		4,4	
Biomethanol	7,2	9,7	8,9	11,3	11,3	13,3
BioDME	7,7		9,5		11,8	
Biodiesel	9,1		10,9		13,2	
BioLMG	9,9	11,9	12,2	13,8	15,0	16,3
BioLBG	9,4	11,4	11,6	13,3	14,3	15,7
HVO	8,2		9,8		11,9	
E-biomethanol	10,4	12,6	12,8	14,7	16,0	17,6
E-bioDME	11,1		13,5		16,7	
E-biodiesel	12,7		15,1		18,4	
E-bioLMG	13,6	15,2	16,6	17,8	20,4	21,2
E-bioLBG	13,0	14,7	15,9	17,2	19,6	20,5
E-methanol	14,3	16,2	17,5	19,0	21,8	22,8
E-DME	15,2		18,5		22,8	
E-diesel	18,0		21,5		26,2	
E-LMG	17,2	18,4	20,9	21,7	25,7	26,0
Ammonia	15,0	16,5	18,5	19,6	23,0	23,6
LH_2	19,2	18,9	24,5	23,5	31,4	29,6

Figure D5: The TCO for bulk carriers in the scenario with high electricity price.

Fuels	Short		Medium		Long	
	ICE	FC	ICE	FC	ICE	FC
MGO	13,5		16,1		17,5	
Biomethanol	30,9	39,7	38,4	46,3	42,4	49,9
BioDME	33,2		40,9		45,1	
Biodiesel	39,8		48,3		52,6	
BioLMG	42,4	48,9	52,5	57,9	58,5	63,2
BioLBG	40,3	47,0	49,9	55,6	55,6	60,7
HVO	35,8		43,4		47,3	
E-biomethanol	45,0	52,4	55,5	61,7	61,2	66,8
E-bioDME	48,0		58,9		64,8	
E-biodiesel	55,3		67,2		73,3	
E-bioLMG	58,6	63,5	72,3	75,8	80,1	82,7
E-bioLBG	56,2	61,3	69,3	73,0	76,8	79,7
E-methanol	62,5	68,1	77,0	81,0	84,5	87,8
E-DME	66,2		81,2		89,1	
E-diesel	78,7		95,9		104,5	
E-LMG	74,5	77,8	91,8	93,2	101,3	101,8
Ammonia	65,2	69,5	80,2	82,9	88,2	90,0
LH_2	82,9	80,5	104,8	100,2	117,9	112,0

Figure D6: The TCO for container ships in the scenario with high electricity price.

2) High biomass price

10 €/GJ (instead of 6 €/GJ) biomass.

Fuels	Short			Medium			Long		
	ICE	FC	BE	ICE	FC	BE	ICE	FC	BE
MGO	0,9			1,70			2,45		
Biomethanol	2,7	4,7		5,1	6,7		7,6	8,7	
BioDME	2,9			5,5			8,1		
Biodiesel	3,4			6,6			9,8		
BioLMG	3,5	5,3		6,5	7,7		9,5	10,1	
BioLBG	3,2	5,1		5,9	7,2		8,5	9,3	
HVO	3,7			7,2			10,6		
E-biomethanol	2,9	4,9		5,6	7,0		8,2	9,2	
E-bioDME	3,2			6,0			8,8		
E-biodiesel	3,5			6,8			10,1		
E-bioLMG	3,9	5,6		7,1	8,2		10,4	10,8	
E-bioLBG	3,8	5,5		7,1	8,1		10,3	10,7	
E-methanol	3,3	5,3		6,5	7,8		9,7	10,3	
E-DME	3,7			7,0			10,3		
E-diesel	4,3			8,4			12,5		
E-LMG	4,3	5,9		8,0	8,9		11,8	11,9	
Ammonia	3,7	5,5		6,9	8,0		10,2	10,6	
LH_2	4,7	5,3		8,8	8,6		13,0	11,9	
Electricity			2,8			5,5			8,3

Figure D7: The TCO for large ferries in the scenario with high biomass price.

Fuels	Short		Medium		Long	
	ICE	FC	ICE	FC	ICE	FC
MGO	1,3		1,5		1,8	
Biomethanol	4,0	4,6	4,8	5,3	6,0	6,2
BioDME	4,2		5,1		6,3	
Biodiesel	5,1		6,1		7,4	
BioLMG	5,1	5,5	6,1	6,5	7,5	7,7
BioLBG	4,5	5,1	5,5	6,0	6,8	7,0
HVO	5,5		6,6		8,1	
E-biomethanol	4,3	4,9	5,2	5,6	6,5	6,6
E-bioDME	4,6		5,6		6,9	
E-biodiesel	5,3		6,3		7,7	
E-bioLMG	5,5	5,9	6,7	6,9	8,2	8,2
E-bioLBG	5,5	5,8	6,6	6,9	8,1	8,1
E-methanol	5,0	5,5	6,1	6,3	7,6	7,5
E-DME	5,4		6,5		8,0	
E-diesel	6,5		7,8		9,5	
E-LMG	6,2	6,4	7,6	7,6	9,3	9,0
Ammonia	5,3	5,6	6,4	6,5	8,0	7,8
LH_2	7,0	6,5	8,7	8,0	11,0	9,9

Figure D8: The TCO for general cargo in the scenario with high biomass price.

Fuels	Short		Medium		Long	
	ICE	FC	ICE	FC	ICE	FC
MGO	3,2		3,7		4,4	
Biomethanol	9,3	11,6	11,5	13,5	14,4	16,1
BioDME	9,9		12,1		15,0	
Biodiesel	11,6		13,8		16,8	
BioLMG	11,9	13,6	14,5	15,9	17,9	18,9
BioLBG	10,7	12,6	13,1	14,7	16,2	17,4
HVO	12,6		15,0		18,3	
E-biomethanol	10,0	12,3	12,4	14,4	15,5	17,1
E-bioDME	10,7		13,1		16,2	
E-biodiesel	12,0		14,3		17,4	
E-bioLMG	12,9	14,6	15,8	17,1	19,5	20,3
E-bioLBG	12,8	14,5	15,6	17,0	19,3	20,1
E-methanol	11,7	13,8	14,3	16,1	17,9	19,3
E-DME	12,4		15,1		18,7	
E-diesel	14,8		17,7		21,5	
E-LMG	14,5	16,0	17,7	18,8	21,8	22,4
Ammonia	12,5	14,2	15,4	16,8	19,3	20,2
LH_2	16,6	16,5	21,4	20,7	27,5	26,2

Figure D9: The TCO for bulk carriers in the scenario with high biomass price.

Fuels	Short		Medium		Long	
	ICE	FC	ICE	FC	ICE	FC
MGO	13,5		16,1		17,5	
Biomethanol	40,3	48,1	49,8	56,6	54,9	61,1
BioDME	43,0		52,8		58,1	
Biodiesel	50,5		61,4		67,0	
BioLMG	51,0	56,7	63,0	67,4	70,0	73,6
BioLBG	46,0	52,1	56,9	61,8	63,2	67,5
HVO	55,0		66,9		73,0	
E-biomethanol	43,7	51,1	53,9	60,2	59,4	65,1
E-bioDME	46,5		57,2		62,9	
E-biodiesel	52,4		63,7		69,5	
E-bioLMG	55,8	60,9	68,8	72,6	76,2	79,2
E-bioLBG	55,1	60,3	68,0	71,9	75,4	78,5
E-methanol	50,8	57,6	62,7	68,1	68,9	73,7
E-DME	54,0		66,3		72,9	
E-diesel	64,7		78,7		85,8	
E-LMG	62,6	67,1	77,2	80,1	85,4	87,4
Ammonia	53,9	59,3	66,3	70,4	73,1	76,4
LH_2	71,4	70,2	90,8	87,6	102,6	98,2

Figure D10: The TCO for container ships in the scenario with high biomass price.

2) Higher FC efficiency

Increase efficiency of FC systems to 60% (base case: 55%).

Fuels	Short ICE	Short FC	Short BE	Medium ICE	Medium FC	Medium BE	Long ICE	Long FC	Long BE
MGO	0,9			1,70			2,45		
Biomethanol	2,0	4,1		3,9	5,4		5,7	6,8	
BioDME	2,3			4,2			6,2		
Biodiesel	2,7			5,2			7,6		
BioLMG	3,0	4,7		5,4	6,4		7,8	8,2	
BioLBG	2,8	4,6		5,1	6,2		7,4	7,9	
HVO	2,4			4,6			6,8		
E-biomethanol	2,6	4,5		4,9	6,2		7,3	8,0	
E-bioDME	2,9			5,4			7,9		
E-biodiesel	3,2			6,2			9,2		
E-bioLMG	3,6	5,1		6,6	7,3		9,6	9,6	
E-bioLBG	3,6	5,1		6,5	7,3		9,5	9,4	
E-methanol	3,3	5,1		6,5	7,4		9,7	9,7	
E-DME	3,7			7,0			10,3		
E-diesel	4,3			8,4			12,5		
E-LMG	4,3	5,7		8,0	8,4		11,8	11,1	
Ammonia	3,7	5,3		6,9	7,6		10,2	9,9	
LH_2	4,7	5,0		8,8	8,0		13,0	11,0	
Electricity			2,8			5,5			8,3

Figure D11: The TCO for large ferries in the scenario with high FC efficiency.

Fuels	Short ICE	Short FC	Medium ICE	Medium FC	Long ICE	Long FC
MGO	1,3		1,5		1,8	
Biomethanol	3,0	3,6	3,7	4,1	4,6	4,8
BioDME	3,3		4,0		4,9	
Biodiesel	4,0		4,8		5,8	
BioLMG	4,2	4,5	5,1	5,2	6,2	6,2
BioLBG	4,0	4,4	4,8	5,1	5,9	5,9
HVO	3,6		4,3		5,2	
E-biomethanol	3,8	4,2	4,7	4,8	5,8	5,7
E-bioDME	4,1		5,0		6,1	
E-biodiesel	4,8		5,8		7,0	
E-bioLMG	5,1	5,2	6,2	6,1	7,7	7,2
E-bioLBG	5,1	5,2	6,1	6,0	7,5	7,1
E-methanol	5,0	5,1	6,1	5,9	7,6	7,0
E-DME	5,4		6,5		8,0	
E-diesel	6,5		7,8		9,5	
E-LMG	6,2	6,0	7,6	7,1	9,3	8,4
Ammonia	5,3	5,3	6,4	6,1	8,0	7,2
LH_2	7,0	6,0	8,7	7,4	11,0	9,1

Figure 12: The TCO for general cargo in the scenario with high FC efficiency.

Fuels	Short		Medium		Long	
	ICE	FC	ICE	FC	ICE	FC
MGO	3,2		3,7		4,4	
Biomethanol	7,2	9,2	8,9	10,6	11,3	12,4
BioDME	7,7		9,5		11,8	
Biodiesel	9,1		10,9		13,2	
BioLMG	9,9	11,2	12,2	13,0	15,0	15,3
BioLBG	9,4	10,8	11,6	12,5	14,3	14,7
HVO	8,2		9,8		11,9	
E-biomethanol	9,0	10,7	11,1	12,4	14,0	14,6
E-bioDME	9,6		11,8		14,6	
E-biodiesel	11,0		13,1		15,9	
E-bioLMG	12,1	13,0	14,7	15,1	18,2	17,9
E-bioLBG	11,9	12,8	14,5	15,0	17,9	17,7
E-methanol	11,7	12,9	14,3	15,0	17,9	17,9
E-DME	12,4		15,1		18,7	
E-diesel	14,8		17,7		21,5	
E-LMG	14,5	15,0	17,7	17,5	21,8	20,8
Ammonia	12,5	13,3	15,4	15,6	19,3	18,8
LH_2	16,6	15,4	21,4	19,3	27,5	24,3

Figure D13: The TCO for bulk carriers in the scenario with high FC efficiency.

Fuels	Short		Medium		Long	
	ICE	FC	ICE	FC	ICE	FC
MGO	13,5		16,1		17,5	
Biomethanol	30,9	37,4	38,4	43,4	42,4	46,6
BioDME	33,2		40,9		45,1	
Biodiesel	39,8		48,3		52,6	
BioLMG	42,4	45,9	52,5	54,1	58,5	58,9
BioLBG	40,3	44,2	49,9	52,0	55,6	56,6
HVO	35,8		43,4		47,3	
E-biomethanol	39,0	44,1	48,2	51,5	53,1	55,5
E-bioDME	41,7		51,2		56,4	
E-biodiesel	48,0		58,3		63,5	
E-bioLMG	51,8	53,7	64,0	63,6	71,0	69,3
E-bioLBG	51,1	53,1	63,1	62,9	70,0	68,5
E-methanol	50,8	53,8	62,7	63,4	68,9	68,5
E-DME	54,0		66,3		72,9	
E-diesel	64,7		78,7		85,8	
E-LMG	62,6	62,6	77,2	74,5	85,4	81,1
Ammonia	53,9	55,4	66,3	65,6	73,1	71,0
LH_2	71,4	65,1	90,8	80,9	102,6	90,6

Figure D14: The TCO for container ships in the scenario with high FC efficiency.

3) Low FC and BE propulsion cost

A reduction of both PEMFC and SOFC costs to 400 €/kWe, and battery cost from 250 €/kWh to 150 €/kWh (base case: PEMFC 730 €/kWe and SOFC 1280 €/kWe).

Fuels	Short			Medium			Long		
	ICE	FC	BE	ICE	FC	BE	ICE	FC	BE
MGO	0,9			1,7			2,4		
Biomethanol	2,0	2,7		3,9	4,2		5,7	5,7	
BioDME	2,3			4,2			6,2		
Biodiesel	2,7			5,2			7,6		
BioLMG	3,0	3,3		5,4	5,3		7,8	7,2	
BioLBG	2,8	3,2		5,1	5,0		7,4	6,8	
HVO	2,4			4,6			6,8		
E-biomethanol	2,6	3,1		4,9	5,0		7,3	6,9	
E-bioDME	2,9			5,4			7,9		
E-biodiesel	3,2			6,2			9,2		
E-bioLMG	3,6	3,8		6,6	6,2		9,6	8,6	
E-bioLBG	3,6	3,8		6,5	6,2		9,5	8,5	
E-methanol	3,3	3,8		6,5	6,3		9,7	8,8	
E-DME	3,7			7,0			10,3		
E-diesel	4,3			8,4			12,5		
E-LMG	4,3	4,4		8,0	7,4		11,8	10,3	
Ammonia	3,7	4,0		6,9	6,5		10,2	9,1	
LH_2	4,7	4,7		8,8	8,0		13,0	11,3	
Electricity			2,2			4,2			6,4

Figure D15: The TCO for large ferries using low FC and BE propulsion cost.

Fuels	Short		Medium		Long	
	ICE	FC	ICE	FC	ICE	FC
MGO	1,3		1,5		1,8	
Biomethanol	3,0	3,0	3,7	3,5	4,6	4,2
BioDME	3,2		3,9		4,8	
Biodiesel	4,0		4,8		5,8	
BioLMG	4,2	3,9	5,1	4,6	6,2	5,6
BioLBG	4,0	3,7	4,8	4,4	5,9	5,3
HVO	3,6		4,3		5,2	
E-biomethanol	3,8	3,6	4,7	4,3	5,8	5,2
E-bioDME	4,1		4,9		6,1	
E-biodiesel	4,8		5,8		7,0	
E-bioLMG	5,1	4,6	6,2	5,5	7,7	6,7
E-bioLBG	5,1	4,6	6,1	5,5	7,5	6,6
E-methanol	5,0	4,6	6,1	5,5	7,6	6,6
E-DME	5,3		6,5		8,0	
E-diesel	6,5		7,8		9,5	
E-LMG	6,2	5,5	7,6	6,6	9,3	8,0
Ammonia	5,3	4,8	6,4	5,7	8,0	6,9
LH_2	7,0	6,1	8,7	7,6	11,0	9,4

Figure D16: The TCO for general cargo ships using low FC and BE propulsion cost.

Fuels	Short		Medium		Long	
	ICE	FC	ICE	FC	ICE	FC
MGO	3,2		3,7		4,4	
Biomethanol	7,2	7,6	8,9	9,2	11,3	11,2
BioDME	7,6		9,4		11,7	
Biodiesel	9,1		10,9		13,2	
BioLMG	9,9	9,8	12,2	11,7	15,0	14,2
BioLBG	9,4	9,3	11,6	11,2	14,3	13,6
HVO	8,2		9,8		11,9	
E-biomethanol	9,0	9,3	11,1	11,1	14,0	13,7
E-bioDME	9,5		11,7		14,5	
E-biodiesel	11,0		13,1		15,9	
E-bioLMG	12,1	11,7	14,7	14,1	18,2	17,1
E-bioLBG	11,9	11,6	14,5	13,9	17,9	16,9
E-methanol	11,7	11,7	14,3	14,0	17,9	17,2
E-DME	12,3		15,0		18,6	
E-diesel	14,8		17,7		21,5	
E-LMG	14,5	13,9	17,7	16,7	21,8	20,3
Ammonia	12,5	12,1	15,4	14,7	19,3	18,1
LH_2	16,6	15,8	21,4	19,9	27,5	25,4

Figure D17: The TCO for bulk carriers using low FC and BE propulsion cost.

Fuels	Short		Medium		Long	
	ICE	FC	ICE	FC	ICE	FC
MGO	14,0		16,7		18,1	
Biomethanol	31,3	32,0	38,7	38,6	42,8	42,2
BioDME	32,8		40,5		44,7	
Biodiesel	40,4		48,9		53,2	
BioLMG	41,9	41,3	52,0	50,3	57,9	55,6
BioLBG	39,8	39,3	49,4	47,9	55,1	53,0
HVO	36,4		44,0		47,8	
E-biomethanol	39,4	39,3	48,6	47,5	53,5	51,9
E-bioDME	41,3		50,9		56,0	
E-biodiesel	48,6		58,9		64,1	
E-bioLMG	51,3	49,7	63,5	60,6	70,5	66,9
E-bioLBG	50,6	49,1	62,6	59,8	69,5	66,0
E-methanol	44,0	43,4	54,2	52,5	59,7	57,4
E-DME	53,6		65,9		72,5	
E-diesel	65,3		79,3		86,4	
E-LMG	62,1	59,4	76,6	72,5	84,8	79,8
Ammonia	53,9	51,6	66,3	62,8	73,1	68,8
LH_2	70,9	67,3	90,3	84,7	102,1	95,4

Figure D18: The TCO for container ships using low FC and BE propulsion cost.

3) High-efficiency ICE and base case FC

Assume 45% for four-stroke engines and 50% for two-stroke engines (base case: 40% for four-stroke engines, 45% for two-stroke engines, and 55% for FC systems).

Fuels	Short			Medium			Long		
	ICE	FC	BE	ICE	FC	BE	ICE	FC	BE
MGO	0,9			1,53			2,20		
Biomethanol	1,8	4,2		3,5	5,7		5,1	7,2	
BioDME	2,1			3,8			5,5		
Biodiesel	2,4			4,6			6,8		
BioLMG	2,7	4,9		4,8	6,8		7,0	8,7	
BioLBG	2,6	4,8		4,6	6,6		6,6	8,4	
HVO	2,2			4,1			6,1		
E-biomethanol	2,3	4,7		4,4	6,5		6,5	8,4	
E-bioDME	2,6			4,8			7,0		
E-biodiesel	2,9			5,6			8,2		
E-bioLMG	3,3	5,4		5,9	7,8		8,6	10,2	
E-bioLBG	3,2	5,3		5,9	7,7		8,5	10,1	
E-methanol	3,0	5,3		5,8	7,8		8,6	10,3	
E-DME	3,3			6,2			9,2		
E-diesel	3,9			7,5			11,2		
E-LMG	3,9	5,9		7,2	8,9		10,5	11,9	
Ammonia	3,4	5,5		6,2	8,0		9,0	10,5	
LH_2	4,2	5,3		7,9	8,5		11,5	11,8	
Electricity			2,8			5,4			8,0

Figure D19: The TCO for large ferries with high ICE efficiency and base case FC efficiency.

Fuels	Short		Medium		Long	
	ICE	FC	ICE	FC	ICE	FC
MGO	1,2		1,4		1,6	
Biomethanol	2,7	3,8	3,3	4,3	4,1	5,1
BioDME	2,9		3,5		4,3	
Biodiesel	3,5		4,2		5,2	
BioLMG	3,7	4,6	4,5	5,3	5,5	6,2
BioLBG	3,5	4,5	4,3	5,1	5,2	6,0
HVO	3,2		3,8		4,6	
E-biomethanol	3,4	4,5	4,2	5,1	5,2	6,0
E-bioDME	3,7		4,4		5,5	
E-biodiesel	4,3		5,1		6,3	
E-bioLMG	4,6	5,4	5,5	6,3	6,8	7,4
E-bioLBG	4,5	5,4	5,4	6,2	6,7	7,3
E-methanol	4,5	5,4	5,4	6,3	6,7	7,4
E-DME	4,8		5,8		7,1	
E-diesel	5,8		7,0		8,5	
E-LMG	5,6	6,3	6,7	7,3	8,2	8,7
Ammonia	4,7	5,6	5,8	6,5	7,1	7,7
LH_2	6,2	6,3	7,7	7,7	9,6	9,4

Figure D20: The TCO for general cargo ships with high ICE efficiency and base case FC efficiency.

Fuels	Short		Medium		Long	
	ICE	FC	ICE	FC	ICE	FC
MGO	2,9		3,4		4,0	
Biomethanol	6,5	9,7	8,1	11,2	10,2	13,2
BioDME	7,0		8,6		10,7	
Biodiesel	8,3		9,8		11,9	
BioLMG	9,0	11,9	11,1	13,8	13,6	16,3
BioLBG	8,6	11,4	10,5	13,3	13,0	15,7
HVO	7,5		8,9		10,7	
E-biomethanol	8,1	11,3	10,1	13,2	12,6	15,7
E-bioDME	8,8		10,7		13,2	
E-biodiesel	9,9		11,9		14,4	
E-bioLMG	11,0	13,8	13,4	16,1	16,5	19,1
E-bioLBG	10,8	13,6	13,2	16,0	16,3	18,9
E-methanol	10,6	13,8	13,0	16,1	16,2	19,2
E-DME	11,3		13,7		16,9	
E-diesel	13,4		16,0		19,4	
E-LMG	13,2	16,0	16,0	18,8	19,7	22,4
Ammonia	11,3	14,2	13,9	16,7	17,5	20,1
LH_2	15,1	16,5	19,3	20,6	24,9	25,9

Figure D21: The TCO for bulk carriers with high ICE efficiency and base case FC efficiency.

Fuels	Short		Medium		Long	
	ICE	FC	ICE	FC	ICE	FC
MGO	12,3		14,7		16,0	
Biomethanol	28,1	39,8	34,0	45,7	37,1	48,8
BioDME	30,2		36,7		40,1	
Biodiesel	36,0		43,7		47,6	
BioLMG	38,8	49,0	47,7	57,8	53,1	63,0
BioLBG	36,8	47,1	45,4	55,5	50,5	60,5
HVO	32,4		39,3		42,8	
E-biomethanol	35,3	47,0	42,9	54,6	46,7	58,4
E-bioDME	37,9		46,0		50,3	
E-biodiesel	43,4		52,7		57,4	
E-bioLMG	47,2	57,5	58,1	68,2	64,3	74,3
E-bioLBG	46,6	56,8	57,3	67,4	63,5	73,4
E-methanol	46,0	57,7	55,9	67,6	60,9	72,6
E-DME	49,0		59,5		65,1	
E-diesel	58,4		71,1		77,4	
E-LMG	56,9	67,2	69,9	80,0	77,3	87,2
Ammonia	48,9	59,4	59,1	69,5	64,3	74,7
LH_2	65,0	70,3	80,8	85,9	90,2	95,0

Figure D22: The TCO for container ships with high ICE efficiency and base case FC efficiency.

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