TECHNO-ECONOMIC ASSESSMENT OF LOW-CARBON HYDROGEN TECHNOLOGIES FOR THE DECARBONISATION OF SHIPPING

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Hydrogen Europe

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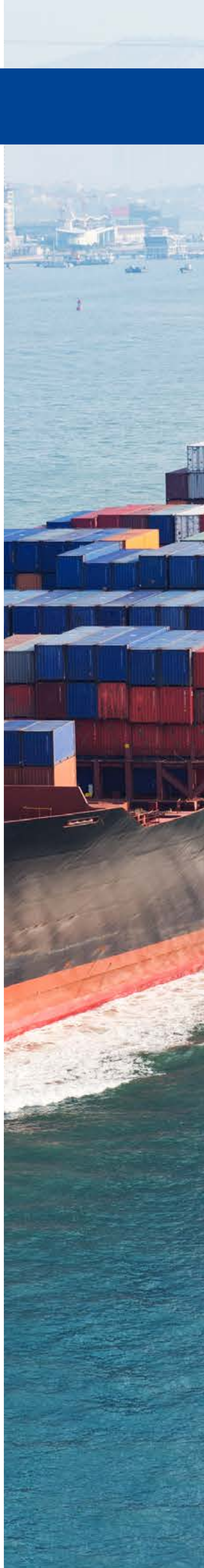


1. Introduction

Hydrogen Europe is the leading European hydrogen and fuel cell association that promotes clean and low carbon hydrogen as the enabler of a zero-emission society. It currently represents more than 270 industry companies and 27 national associations. Its member companies are of all sizes and represent the entire hydrogen value chain, from production to transport, distribution and final end-use of hydrogen. HE represents the common interests shared by stakeholders of the hydrogen and fuel cell industry in the EU. The association partners with the European Commission in the innovation program Fuel Cells and Hydrogen Joint Undertaking (FCH JU).

Hydrogen Europe supports carbon-free/neutral hydrogen production pathways to enable a zero-emission society and promotes hydrogen technologies to achieve the Paris Agreement's climate targets. It fully adheres to the European Union’s target of carbon neutrality by 2050 and supports the European Commission’s objectives to develop and integrate more renewable energy sources into the European energy mix.

As a non-profit trade association, Hydrogen Europe plays a crucial role in promoting best practice, helping companies become more competitive, formulating effective public policies, providing market, policy and technical intelligence, and networking support to its members. Thanks to its broad and various membership, Hydrogen Europe has a full overview of the industrial and market landscape and a direct, privileged connection with the hydrogen and fuel cell industry.

The following publication contains a techno-economic analysis of various pathways for the decarbonisation of global shipping. The analysis is made on the basis of the total cost of ownership comparison and covers all sea-going vessels - from ships used exclusively for short sea application, e.g., ferries, ro-ro ships, general cargo ships and small containerships, through cruise ships and up to ships used mostly on intercontinental voyages, e.g., VLCCs, VLBCs and large containerships.

The paper was developed as part of the preparation of the Strategic Research and Innovation Agenda (SRIA) of the foreseen Clean Hydrogen for Europe partnership (CHE). CHE is the third EU public-private partnership dedicated to the development of clean hydrogen technologies and a successor to the Fuel Cell and Hydrogen 2 Joint Undertaking (FCH2JU).

The purpose of this analysis was to assess the long-term viability of various hydrogen-based solutions for the full decarbonization of shipping and use the results of this assessment as guidance in defining the research and innovation priorities of CHE for the 2021-2027 period. More specifically, the goal was to see what role can hydrogen technologies and hydrogen itself play in reducing the greenhouse gas (GHG) footprint of international shipping, which solutions work best for which ship types and applications and what are the techno-economic barriers for wide adoption of hydrogen as a marine fuel.

Given the stated purpose, the analysis has a forward-looking outlook, not only assessing options based on their current technology readiness level but also taking into account their expected development over the coming years. Consequently, the results of this report should not be seen as a recommendation of the best available solutions today but rather as a projection of the long-term viability of different hydrogen-based options.

Another consequence of the purpose of the analysis is the fact that it covers only options that are within the potential remit of CHE. In other words, the focus is on hydrogen and technologies that are out of the scope of the partnership have been omitted. This does not, however mean that the analysis covers only hydrogen as a fuel. While using hydrogen directly is the most energy-efficient option, it is also possible to use it as an ingredient to produce synthetic e-fuels, which are particularly attractive for deep-sea shipping applications, where energy density of the fuel is key. The synthetic e-fuels, produced from hydrogen, included in this paper are ammonia, liquefied natural gas (LNG), methanol and diesel.

Although there are many pathways to produce clean hydrogen, this analysis includes exclusively hydrogen produced from renewable energy.

The report was prepared by the Hydrogen Europe Secretariat with help from member companies of Hydrogen Europe and Hydrogen Europe Research as well as non-members active in the Maritime Working Group of Hydrogen Europe.

2. Executive summary

In December 2015 in Paris, the global climate agreement was reached at the UN Climate Change Conference COP 21 ("the Paris Agreement"). This agreement is regarded as a historic and landmark instrument in climate action. However, it lacks emphasis on international maritime transport and the role that this sector will need to play in contributing to the decarbonisation of the global economy and striving for a clean planet for all.

The maritime sector is an important part of the world economy and facilitates a large majority of international trade. At the same time, because of the significant negative environmental and health impacts of PM and NOx emissions, any decarbonization efforts should also support the reduction of air pollution generated by the maritime sector.

Improving the energy efficiency of the ship only will not be enough. if the EU, in line with the European Green Deal targets, aims to reduce emissions overall by 55% in 2030 compared to 1990 and have a climate-neutral economy by 2050, a shift from fossil fuels to zero-carbon fuels for shipping will be required. Furthermore, as ships ordered in the next years will impact emissions of the shipping sector for decades to come, if the emission reduction targets of the EU are to be taken seriously, not only is the decarbonization of the shipping sector needed, it needs to start now.

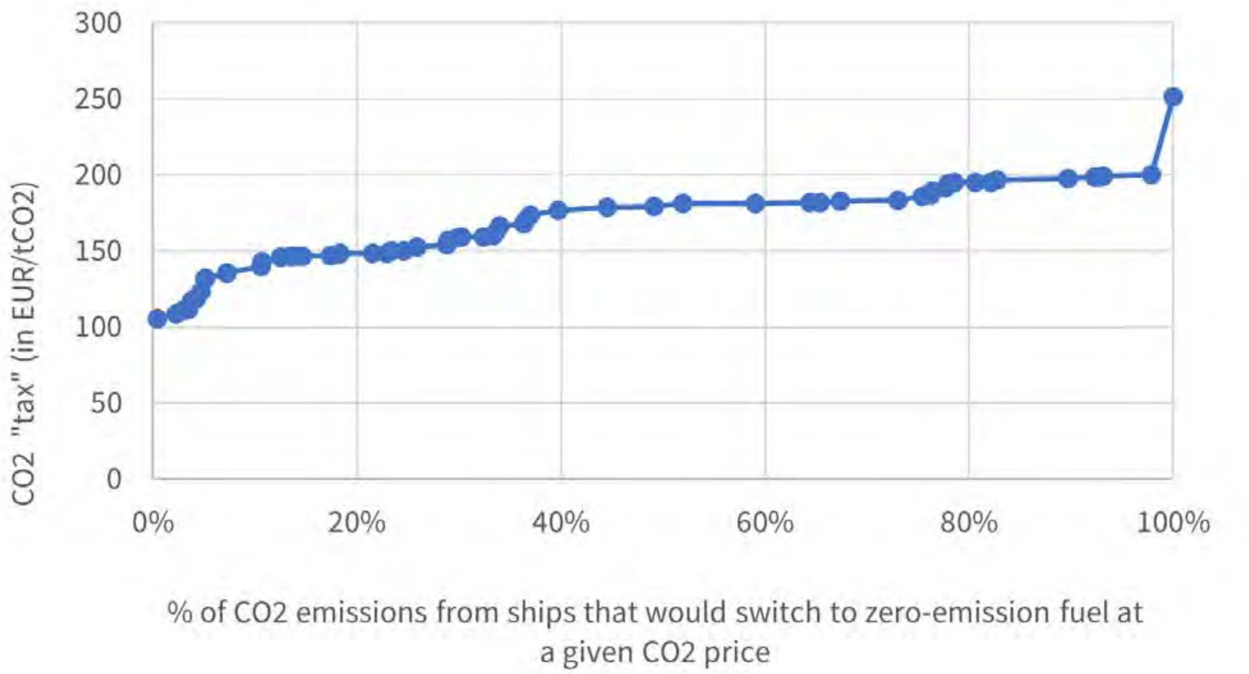
The drive towards the decarbonization of shipping is getting stronger both from the side of policymakers and governments as well as the industry itself. Yet, so far, the deployment of alternative fuels in shipping has been slow and mostly centred around LNG - with questionable climate sustainability.

If produced from nuclear or renewable energy, hydrogen, and its derivatives, enable a reduction of 100% Well-to-Wake GHG emissions. Thus, hydrogen, hydrogen-based fuels (such as ammonia) and hydrogen technologies offer tremendous potential for the maritime sector and, if properly harnessed, can significantly contribute to the decarbonisation of the worldwide fleet.

Even though the interest in hydrogen is growing, there are still some key barriers that need to be overcome before hydrogen can become a mainstream solution for shipping. The key one is obviously the cost of the zero-emission solution compared to conventional fuel oils. Even with relatively low hydrogen production costs of 2.4 EUR/kg, foreseen for 2030, all analysed alternative fuels would be significantly more expensive than the fossil fuel reference. This is, of course, not unexpected, given the low fossil fuels costs and marine fuels exempted from taxation.

Our analysis shows that, depending on the ship type, for the CO2 price to provide a sufficient incentive to switch from fossil fuel oils to zero-emission fuels, it would have to be between 100 EUR/tCO2 to 250 EUR/tCO2. Thus, a CO2 price of around EUR 150 per tonne would be needed for a fuel switch of ships responsible for around 25% of GHG emissions, while EUR 180 per tonne would be sufficient to result in around 75% reduction. Given that one tonne of marine fuel oil, when combusted, emits around 3.1 tCO2, a carbon price of 180 EUR/tCO2 would mean extra fuel costs of around 560 EUR/t.

Figure 1. Cumulated shipping CO2 emission savings as a function of the carbon tax



Source: Hydrogen Europe own elaboration.

This is, of course, well above the current EU Emission Trading System (ETS) CO2 emission allowance price of around EUR 25 per tonne of CO2 (78 EUR/t of fuel). As a result, it is clear that if the inclusion of the maritime sector in the ETS would be the only measure undertaken at the EU level to accelerate the decarbonization of shipping, it might not have the desired impact.

Another consideration is the volumetric energy density of hydrogen and hydrogen-based e-fuels. With a volumetric energy density of around 0,81 kWh/l, one cubic meter of hydrogen compressed at 350 bar contains 12 times less energy than a comparable volume of marine gasoil (MGO) and 7 times less than LNG. One cubic meter of liquid hydrogen contains over 4 times less energy than MGO and 2.5 times less than LNG. This means that either a ship would have to refuel more often, losing some operational flexibility, or it would have to carry an extra volume of fuel, losing some of its payload carrying capacity, and by extension – potential to generate revenues.

The impact of lower volumetric energy density will, of course, vary case by case and will depend not only on the chosen technology but will also greatly depend on the ship's operational profile. It will be most felt in deep-sea shipping applications, where ships need to be able to travel thousands of nautical miles or for ships engaged in tramp trade without a fixed schedule, requiring additional fuel autonomy to ensure high operational flexibility, which is key for their business model. On the other hand, when ships operate on fixed and relatively short routes, then - even for quite large vessels, like ro-pax ferries – it is possible to use even compressed hydrogen as a solution.

It should also be mentioned that there are still plenty of opportunities in the shipping sector to increase the energy efficiency of ships, thus reducing the amount of fuel that needs to be stored onboard and reduce the economic importance of fuel energy density. Technical and operational measures like:

- hull shape optimisation,
- use of lightweight materials,
- air lubrication,
- hull resistance reduction devices,
- ballast water reduction,
- hull coating improvements,
- speed and voyage route optimisation,

can increase the energy efficiency of ships by 20-30%. Combined with other alternative power solutions, like wind assistance, these measures can be therefore seen as enablers for clean, sustainable fuels uptake in the maritime sector.

The higher energy efficiency of fuel cells compared to internal combustion engines can also partially offset hydrogens' lower volumetric energy density.

Other barriers to the adoption of zero-emission fuels are, of course, insufficient bunkering infrastructure. The regulatory framework is also lagging, both in terms of technical regulation as well as policies. Furthermore, a lack of consensus on what will be the future fuel of choice is holding back investments needed for hydrogen to move from the R&D phase into wider adoption. Tackling this uncertainty was also one of the main purposes of this report.

Hydrogen Europe has looked at the available technologies, their strengths and weaknesses, and their technology readiness levels (TRL) to propose deployment scenarios for ships and associated infrastructure. A tool was developed containing 61 ship types to assess which fuel type is the most cost-efficient.

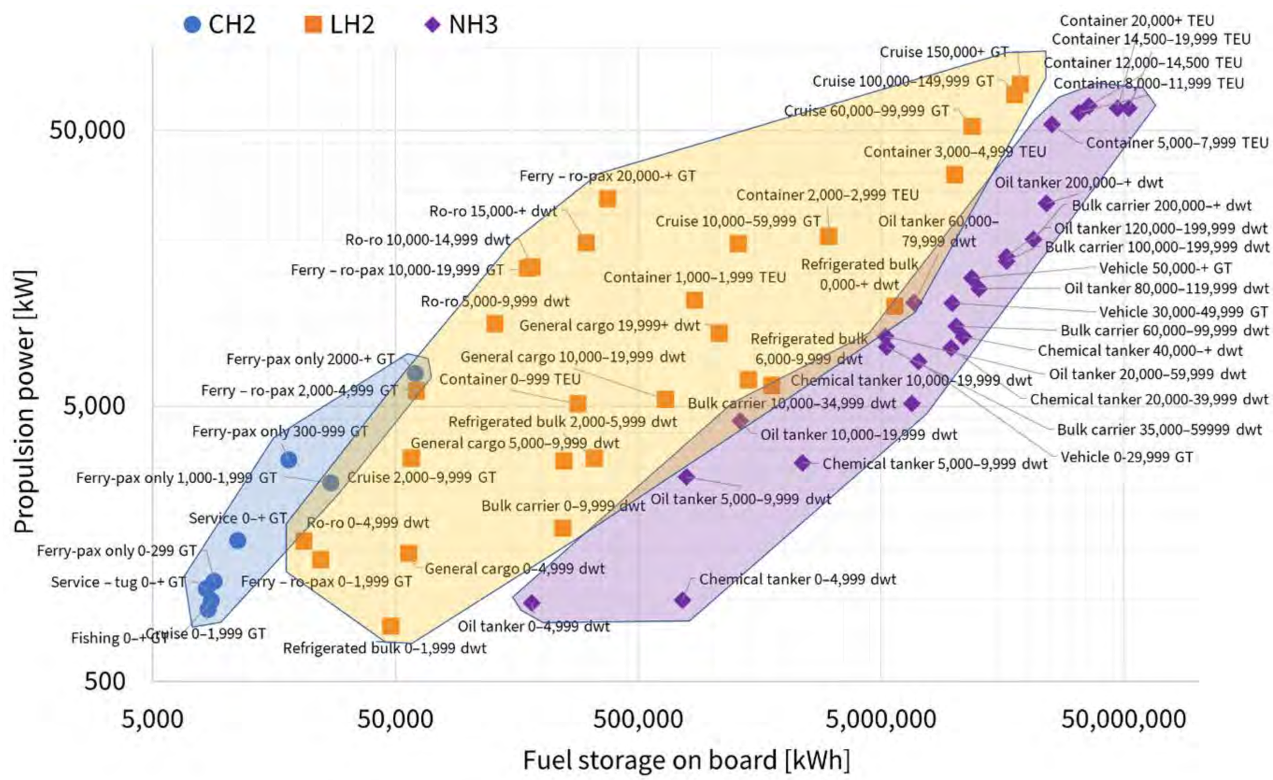
Taking into consideration the costs of the fuel itself, the costs of the required onboard equipment, as well as when repeating the exercise for all 61 ship types in the database, what the results show is that out of all analysed options, it is **only three that ever come out as the most cost-efficient:**

- **Compressed hydrogen with PEM FC** (proton-exchange membrane fuel cells) or relatively small ships with an operational profile that allows for frequent refuelling, limiting the required amount of fuel that needs to be stored onboard.

- **Ammonia with SOFC** (solid oxide fuel cell) for deep-sea shipping applications or smaller vessels with high-value cargo (e.g., chemical tankers), for which storing enough energy using low energy density fuels like compressed hydrogen is not possible, or the payload is so valuable that it is profitable to use a more expensive synthetic fuel to limit revenue loss.

- **Liquefied hydrogen with PEM FC** for every ship in between. This option seems to give the optimum balance between fuel cost and energy density, and as long as the impact of its relatively lower energy density versus synthetic fuels on payload capacity loss is not excessively high, it is the most cost-effective option for most ships.

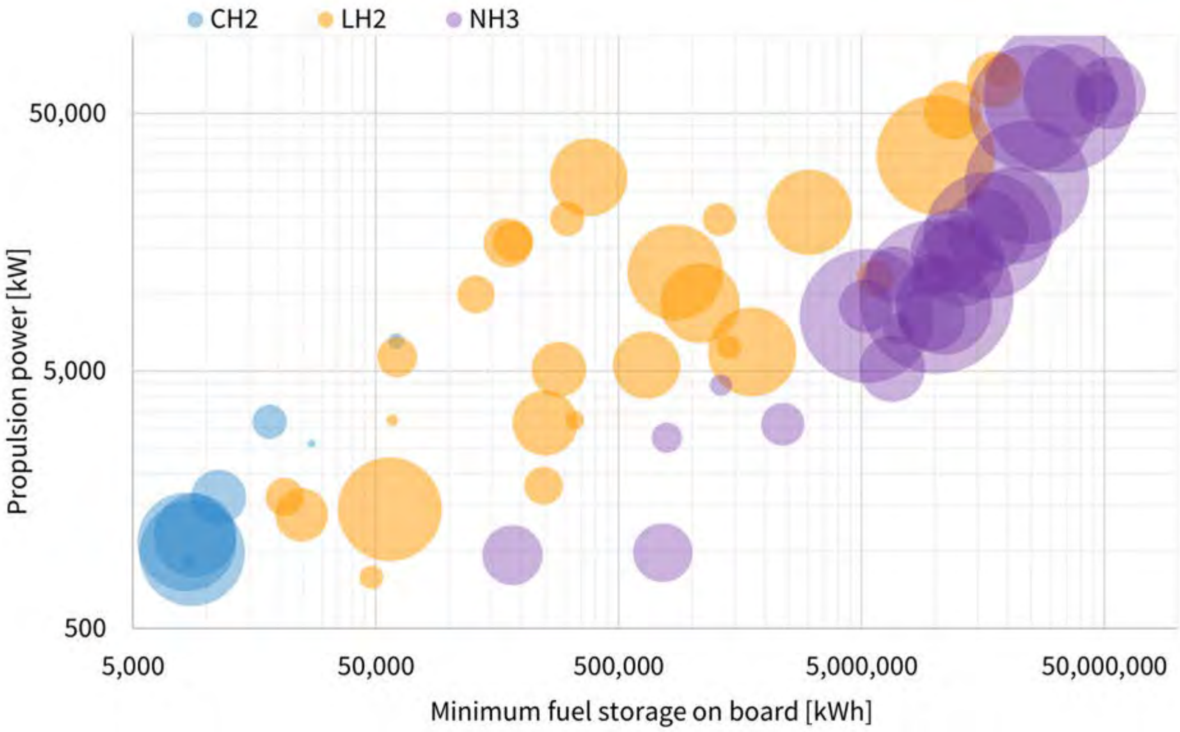
Figure 2. Optimum zero-emission option for various ship types



Source: Hydrogen Europe own elaboration.

While liquefied hydrogen seems to be the optimal solution for most ships, in terms of total energy demand, both compressed and liquefied hydrogen are dominated by synthetic fuels (e-ammonia). 91.4% of all fuels would be used by ships running on e-ammonia with liquefied hydrogen's share at 8,6% and compressed hydrogen below 0.1%.

Figure 3. Optimum zero-emission option for various ship types and their relative total energy demand (size of the bubble)

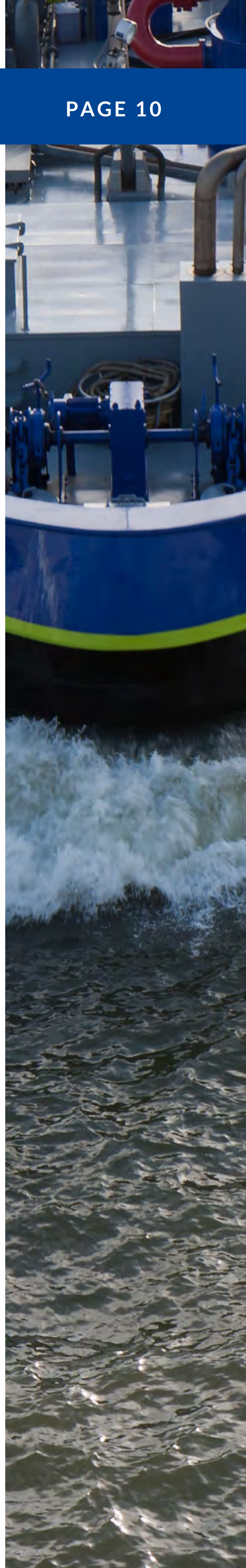


Source: Hydrogen Europe own elaboration.

It should also be stressed that hydrogen has a much broader role in the decarbonisation of the economy than just as a zero-emission fuel. Hydrogen is the only sufficiently available and scalable technology for sector coupling, which is essentially energy system optimization through production and consumption management in different sectors. Deep decarbonisation across all sectors of the economy would be improbable and prohibitively expensive without hydrogen. The role of hydrogen in ongoing decarbonisation efforts has also been recognized in the EU Energy System Integration Strategy and then in the EU Hydrogen Strategy, announced in July 2020, which sets out a target of at least 10 million tonnes of clean hydrogen production in the EU by the end of 2030.

From the point of view of the maritime sector, it is also important to point out the central role that the maritime ports have in the transition towards the hydrogen economy. Already today, a large portion of hydrogen industrial production and consumption takes place in ports or close proximity to ports. The biggest hydrogen consumers come from the oil refining, ammonia and chemical industries, which combined use around 90% of all hydrogen produced each year in the EU. Quite a lot of those facilities are located in ports. This opens up two important opportunities. First, as grey hydrogen will gradually need to be replaced with renewable or low carbon hydrogen, having a large hydrogen demand in ports makes it possible to develop a clean hydrogen supply chain for shipping, already at a large enough scale to benefit from the economies of scale, even if the demand for hydrogen from shipping itself would take time to grow.

This could be further strengthened by the fact that many port areas also host other industrial facilities from the so-called “hard-to-abate” sectors, like the steel industry, which are also increasingly looking at hydrogen as an option for decarbonisation. Combined with the fact that hydrogen can also be used as a fuel for most material handling vehicles operating in port’s terminals, as well as considering the opportunity to import low-cost renewable hydrogen from, e.g., Chile or Saudi Arabia via sea trade, it is becoming clear that maritime ports are set to become key hubs of the emerging hydrogen economy.



3. The maritime sector and the need for decarbonisation

3.1 Basic information about the maritime sector

Decarbonisation effort aimed at the shipping sector should follow a least-cost pathway to minimise the negative impact on international trade.

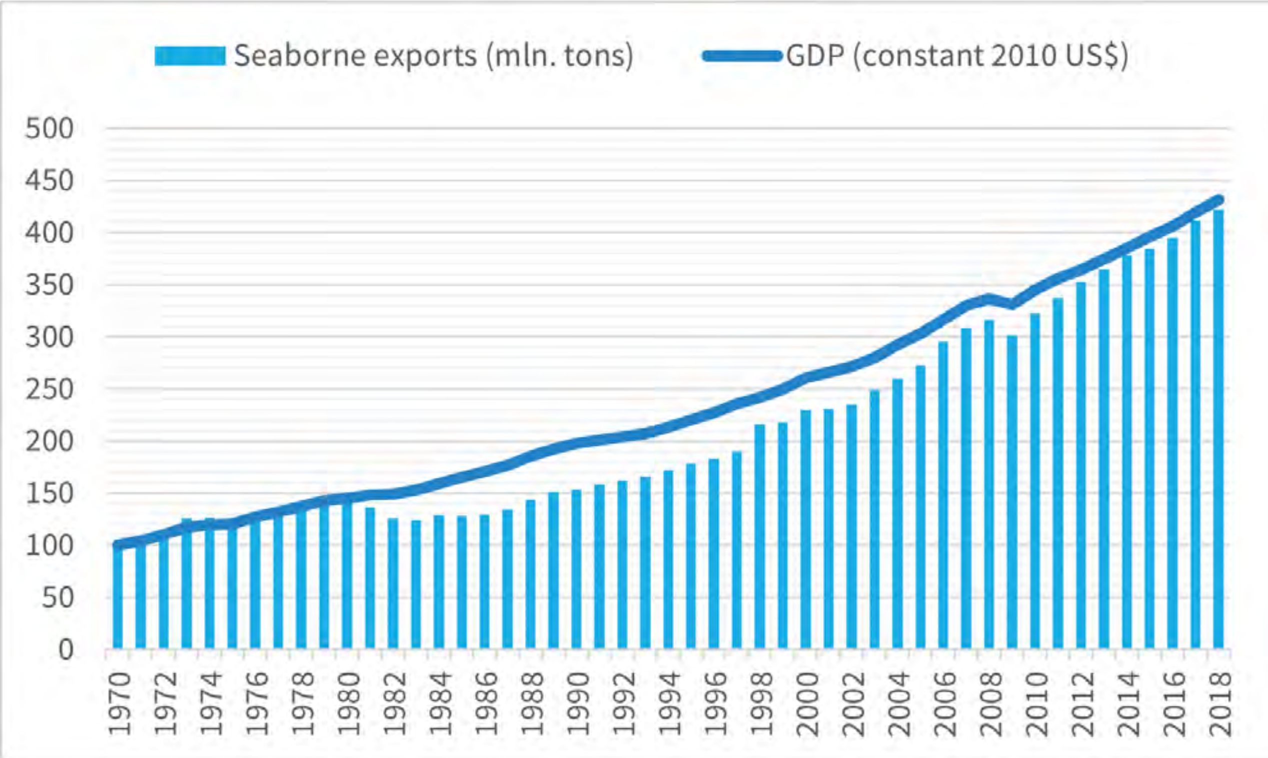
The marine transportation system is a complex network of specialised vessels, ports, factories, terminals, and distribution centres that supplies our society with goods from around the world that are more efficiently produced away from their point of consumption. In our interconnected world, self-sufficiency is given away to economic efficiency. Hence, every country relies on the maritime sector to sell its produced surplus goods and purchase what it lacks.

Maritime shipping is an integral part of the global freight transportation system. Often, coastwise, short sea, inland river, or ocean shipping compete with other freight modes such as air, road or rail. But in some cases, they constitute the only available option of moving goods from manufacturers to consumers. [1]

The maritime sector continues to be the backbone of the global economy as it transports over 80% of global trade by volume and more than 70% of its value. Its importance for economic efficiency, economic development, and societal prosperity is crucial. [2]

Given its importance to the global economy, seaborne trade is closely associated with economic growth. Its volume has more than quadrupled since 1970, and so has the GDP adjusted for inflation. Figure 1 provides developments indexed to 1970 and shows that seaborn exports have risen 322% from 1970 to 2018 while GDP has risen 332% during the same period. This development reflects the close connection between GDP as a measure of economic activity and seaborne trade.

Figure 4. Seaborne exports and global GDP 1970-2018 (1970 = 100).



Source: [3].

The fourfold increase in seaborne exports in the last 49 years has facilitated trade and the emergence of globalization as the world realized the importance of transportation to align demand for goods and resources in population centres with their supply in production centres.

Globalization, defined by Merriam-Webster as "the development of an increasingly integrated global economy marked especially by free trade, free flow of capital, and the tapping of cheaper foreign labour markets", has been largely facilitated by cheaper maritime transportation costs, which have facilitated large scale industrial production in both developing and emerging markets.

The decreasing transportation costs, together with the gradual removal of trade barriers, increasing capital mobility, and advances in information technology, have fuelled our world's increasing interconnectedness in the last fifty years and the accompanied economic growth. [4] Declining shipping costs stopped protecting producers whose main competitive advantage was their proximity to their customers.

The transition from local or regional supply chains to global ones can be observed in the oil and petrochemicals industry. Until the 1950s, most of the produced crude oil was refined in proximity to its production and subsequently transported to market in small tankers of up to 30,000 deadweight tonnage.

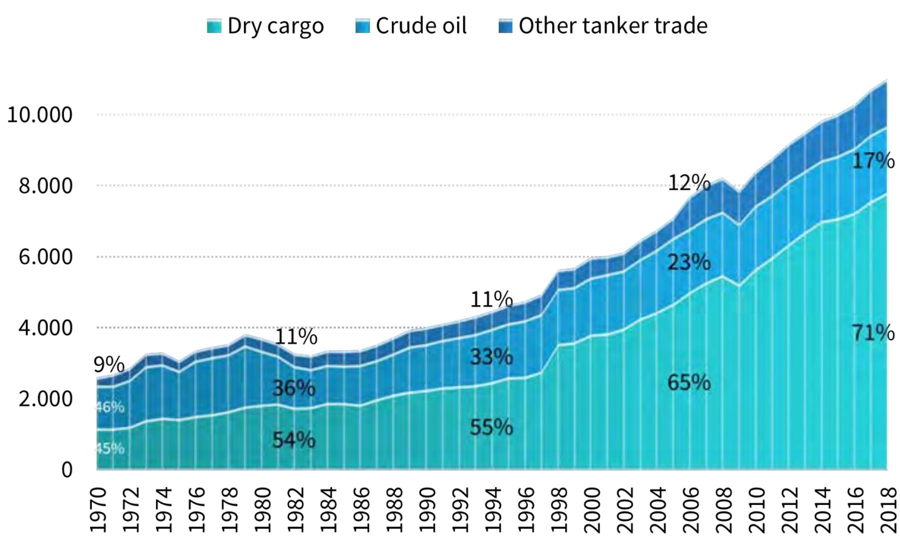
However, market economics and economies of scale pointed to increased efficiency from shipping crude oil to refineries closer to demand centres. From there, it can be distributed through a variety of transportation modes to the customers [1]. As a result, in post-war reconstruction years, oil demand led to crude oil travelling longer distances and in larger quantities. The newest and largest supertanker in 1956, Universe Leader, had 85,515 DWT. [5] The economic efficiency of central refining led to the gradually increasing size of crude oil tankers, with the current ultra-large crude carriers reaching 415 meters in length and more than 320,000 DWT with some exceeding 500,000 DWT. [6]

In addition to crude and petroleum products, manufactured merchandise and bulk transport have dominated global shipping since the 1960s. Similar to crude oil shipping, bulk shipping of raw agricultural products, raw materials, and other commodities has quickly gained prominence as it was delivering these raw materials to processing facilities closer to their final markets.

The real revolution in global shipping came with the emergence of containerships in 1956 and their proliferation in the subsequent decade. Containerization has simplified intermodal transportation and decreased transaction and handling costs associated with shipping non-standardized goods thus, completely transforming the global merchandise trade and the shape of the world economy. [7] Currently, for one tonnage of general cargo ships, there is 3.5containership tonnage.

The increasing importance of both bulk cargo and container shipping has been shown in Figure 2. Dry cargo export volumes, including bulk cargo and containers, have increased by 570% from 1970 to 2018, representing an annual growth rate of 4%. The dry cargo share of total exports increased from 45% in 1970 to 71% in 2018. Crude oil and other tanker products represented 55% of total seaborne exports in 1970, while their share decreased to 29% in 2018.

Figure 5. Seaborne exports by type (1970 – 2018) in million tonnes



Source: [3]

As a result of increased maritime transportation, even previously small harbours such as Busan, South Korea, and Seattle, Washington became global ports. Other new ports were built in places aiming to benefit from the new global supply chain and manufacturing. These include Felixstowe in England that built its container terminal in 1967 and now deals with 37% of Britain's containerized trade. [8] [9] Another example is the port of Tanjung Pelepas in Malaysia that started operations in 2000 and, like so many others, facilitated the economic development of the countries around it by allowing them to become part of the global supply chains and therefore take advantage of their lower manufacturing costs. In the developed world, port cities such as Los Angeles and Hong Kong benefited from new industrial complexes that were only profitable due to the low shipping cost of importing raw materials and exporting finished merchandise. [7]

While much of the initial increase in participation from developing countries in global supply chains occurred in the 70s, 80s, and 90s, developing countries continue to increase their connectedness to and share of the global economy via maritime trade.

What all the above data shows is that maritime transport is an indispensable part of the world economy. Today, **maritime transport remains the backbone of the globalised trade and the manufacturing supply chain, as more than four-fifths of world merchandise trade by volume is carried by sea** [3].

Therefore, it is of utmost importance that any decarbonisation effort aimed at the shipping sector should follow a least-cost pathway to minimize the negative impact on international trade.

Furthermore, because of the strong interconnectedness of the international shipping industry, it is equally important for action to be taken as much as possible at a global rather than regional or national level.

The above points are even more important now when it is becoming increasingly clear that the ongoing COVID-19 crisis is having and will continue to have a significant negative impact on both the world economy, international trade, and the shipping industry.

3.2 Why is the decarbonisation of shipping needed?

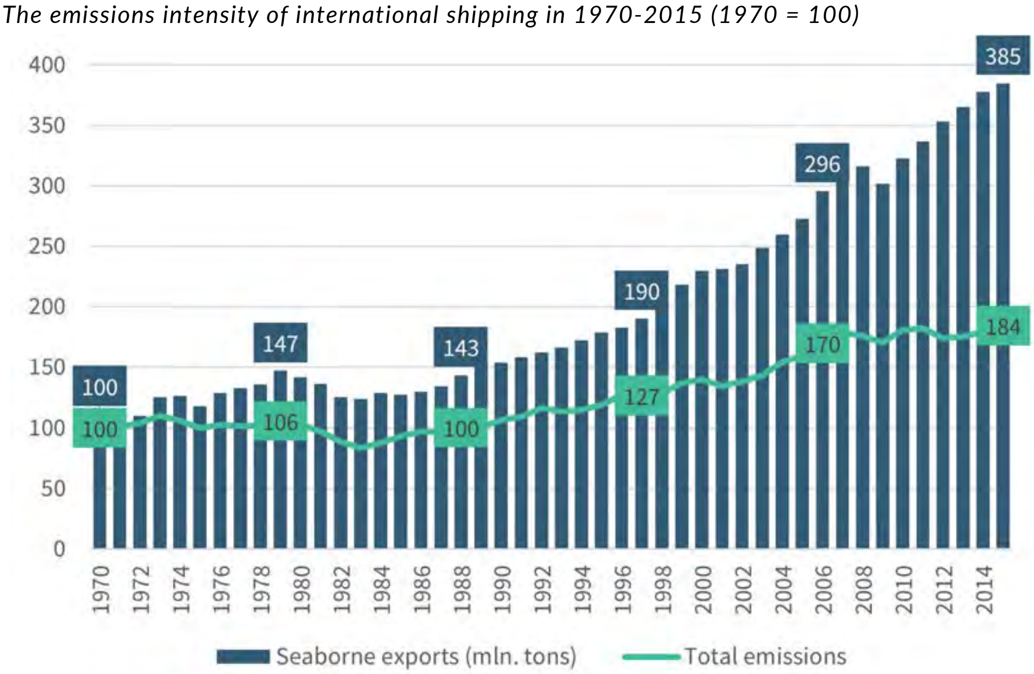
Energy efficiency improvements will not be enough, and if the EU, in line with the European Green Deal targets, aims to reduce emissions by 55% in 2030 relative to 1990 and have a net-zero emission economy by 2050, a shift from fossil fuels to zero-carbon fuels for shipping will be required.

While it is clear that the maritime sector is an important component in the world's economy, it is also becoming increasingly clear that urgent action is needed to tackle the sector's ever-growing emissions. The global shift towards renewable and sustainable energy to limit the most severe effects of climate change is a challenge for every sector, including maritime shipping. The International Maritime Organisation (IMO)'s commitment to reduce GHG from shipping by 50% by 2050, environmental pressures from investors and customers, and other environmental regulations are forcing the maritime shipping sector to analyse its decarbonisation opportunities closely.

According to a recent IMO study, the **GHG emissions** – including carbon dioxide (CO2), methane (CH4), and nitrous oxide (N2O), expressed in CO2 equivalent (CO2e) – of the whole shipping sector (international, domestic, and fishing) **have increased from 977 million tonnes in 2012 to 1,076 million tonnes in 2018** (9.6% increase). In 2012, shipping emitted 962 million tonnes of CO2, while in 2018, this amount grew 9.3% to 1,056 million tonnes of CO2 emissions. Furthermore, the same study estimates that 2008 international shipping GHG emissions (in CO2e) were 794 million tonnes. This means that between 2008 and 2018, the GHG emissions from the shipping sector grew by more than 35%. [10] [11]

The shipping sector's greenhouse gas emissions (CO2, CH4, and N2O) have been steadily rising over the last 45 years at a compounded annual growth rate of 1.37% between 1970 and 2015. However, seaborne exports, a measure for maritime shipping activity, have been rising at an annual rate of 3% during the same period. The lower annual increase led to a total GHG emissions increase of only 84% compared to seaborne exports growth by 284% during these 45 years. This development is visible in Figure 3, which tracks the emission intensity of shipping by indexing seaborne exports and total emissions to 1970 levels.

Figure 6. The emissions intensity of international shipping in 1970-2015 (1970 = 100)



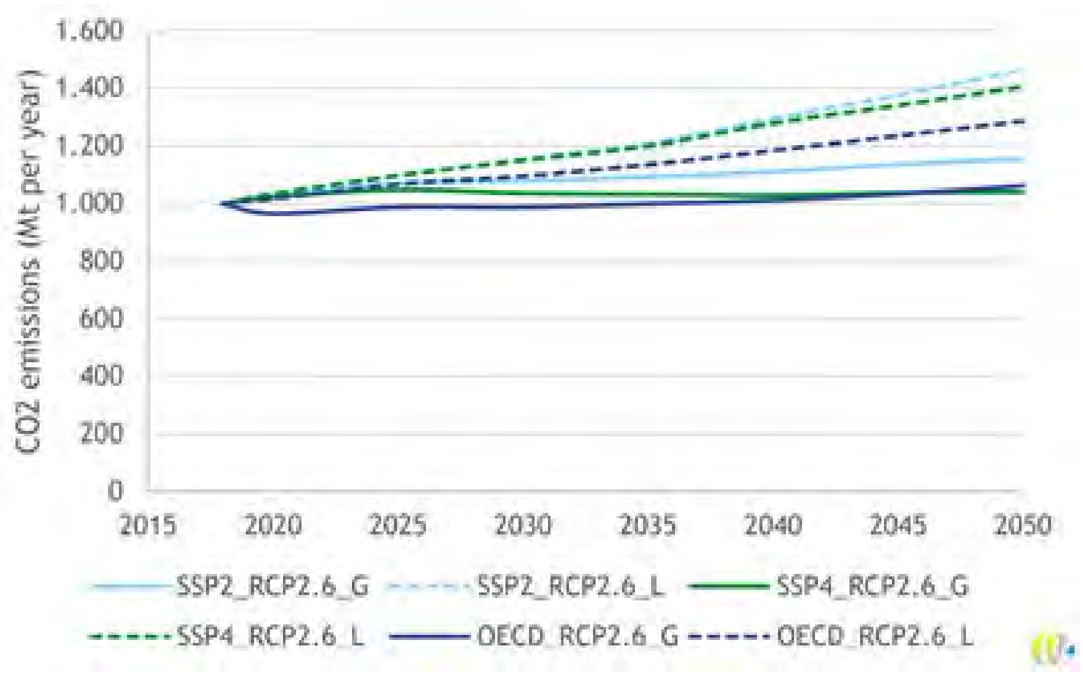
Source: Hydrogen Europe own elaboration based on [3] and [12].

With regards to domestic vs international shipping emissions, domestic shipping had a 20.1% share in 1970, growing at 1.29% annually and attaining 19.4% in 2015. International shipping's share has slightly increased from 79.9% in 1970 to 80.6% in 2015 by growing at a higher annual rate of 1.39%. The difference is due to the previously mentioned increased participation of developing economies in the global supply chain in the last 45 years. [10]

In total, maritime shipping's share of total global emissions has declined from 2.8% in 1970 to 2.2% in 2015. Yet, since then, **the shipping sector's share in global emissions has been growing steadily and has reached 2.9% in 2018**, surpassing the level recorded in 1970. [10] At the EU level, according to the MRV database, CO2 emissions of maritime shipping amounted to over 142 Mt in 2018 and 136 Mt in 2019. [13] **This amounts to ~4% of total EU GHG emissions.**

Assuming the COVID-19 pandemic has only a temporary effect on the world economy, the waterborne trade is expected to continue to grow in the coming years and decades. As a result – although **ships can improve their efficiency by a further 20-30% by technical and operational means** – the growth in transport work will ensure that, even if those efficiency improvements are fully implemented, the absolute GHG emissions of the shipping sector will also continue to grow. The fourth IMO GHG study predicts that in business-as-usual scenarios, which includes only the continuation of efficiency improving actions, the absolute GHG emissions from shipping will remain stable at best but can potentially grow by more than 40%, depending on the global GDP growth.

Figure 7. BAU shipping CO2 emissions (Mt per year) for different GDP growth scenarios.



Source: [10]

This clearly shows that ship energy efficiency improvements will not be enough, and if the EU, in line with the European Green Deal targets, aims to reduce emissions by 55% in 2030 relative to 1990 and have a net-zero emission economy by 2050, a shift from fossil fuels to zero-carbon fuels for shipping will be required.

3.3 Air pollution – shipping sector's other problem

Maritime shipping's essential role in our global economy is indisputable, but it is a significant contributor to global air pollution that harms both human health and the environment.

Although the main focus of this paper is GHG emissions, one should not forget that the shipping sector is also a significant source of air pollution. Maritime shipping's essential role in our global economy is indisputable, but it is a major contributor to global air pollution that harms human health and the environment.

The sum of air pollutants in thousands of tonnes from shipping divided by seaborne exports in million tonnes has decreased by 48% between 1970-2015. This is mostly due to the increased efficiencies of ship engines as well as larger shipping vessels which decrease emitted air pollution per unit of weight transported. Yet, (also not dissimilarly to GHG emission development) due to an overall increase in maritime transport, absolute pollutants emissions generated by shipping during 1970–2015 have been increasing on average by 1.6% annually and, as a result, have doubled from 21.8 billion tonnes in 1970 to 43.9 billion tonnes in 2015.

The fourth IMO GHG study estimates that international shipping emitted in 2018 was approximately 17.1 million tonnes of NOx emissions and 9.6 million tonnes of SOx emissions compared to 16.9 and 9.6 million tonnes respectively in 2012. This represents an annual increase of 0.2% for NOx and 0.9% for SOx. [10]

The air pollutants from ships' exhaust further decrease the overall air quality that is already insufficient in many areas, and also affect the natural environment. At high concentrations, gaseous SOx can harm trees and plants by damaging foliage and decreasing growth. SO2 and other sulphur oxides can contribute to acid rain, which can harm sensitive ecosystems. [14] NOx gases react to form smog and acid rain as well as being central to the formation of fine particles (PM) and ground-level ozone, both of which are associated with adverse health effects [15], causing tens of thousands of premature deaths worldwide each year, mostly in the European Union, China, and India. [16] Because of the significant negative environmental and health impacts, decarbonisation efforts should also support the reduction of air pollution generated by the maritime sector.

It should be noted, however, that, the maritime sector has in recent years undertaken some significant steps to reduce air pollution it is responsible for.

The International Convention for the Prevention of Pollution from Ships (MARPOL) in its Annex VI first started to limit main air pollutants contained in the ships exhaust gas in 1997. These regulations limit emissions from sulphur oxides (SOx), nitrogen oxides (NOX), ozone (O3)-depleting substances and volatile organic compounds (VOC).[1] MARPOL Annex VI went through various revisions since then to become means of progressive reduction of emissions of SOx, NOx, and particulate matter as well as means of introducing emission control areas (ECAs) which can be used to require more stringent standards applicable to SOx and PM, NOx.

The currently established ECAs include:

- Baltic Sea area – (SOx only),
- North Sea area – (SOx only),
- North American area – (SOx, NOx and PM),
- The United States Caribbean Sea area - (SOx, NOx and PM).

Table 1. Overview of SOx limits

Outside an ECA SOx limits	Inside an ECA SOx limits
4.50% m/m prior to 1 January 2012	1.50% m/m prior to 1 July 2010
3.50% m/m on and after 1 January 2012	1.00% m/m on and after 1 July 2010
0.50% m/m on and after 1 January 2020	0.10% m/m on and after 1 January 2015

Source: IMO

As a result of those actions, SOx emissions inside and outside of ECA zones have been dramatically reduced since 1 January 2020.

When it comes to NOx different levels (Tiers) of control apply based on the ship construction date. Within any particular Tier the actual limit value is determined from the engine's rated speed:

Table 2. Overview of NOx limits

Tier	Ship construction date on or after	Total weighted cycle emission limit (g/kWh) n = engine's rated speed (rpm)		
		n < 130	n = 130 - 1999	n ≥ 2000
I	1 January 2000	17.0	$45 \cdot n^{(-0.2)}$ e.g., 720 rpm – 12.1	9.8
II	1 January 2011	14.4	$44 \cdot n^{(-0.23)}$ e.g., 720 rpm – 9.7	7.7
III	1 January 2016	3.4	$9 \cdot n^{(-0.2)}$ e.g., 720 rpm – 2.4	2.0

Source: IMO.

1 http://www.imo.org/en/OurWork/Environment/PollutionPrevention/AirPollution/Pages/Air-Pollution.aspx

Ship operators have been securing compliance to SOx and NOx standards through either switching to different fuels or installing emission/pollution abatement systems such as SOx scrubbers or various Selective catalytic reaction systems for reducing NOx emissions. As of May 2020, Clarksons Research identifies 3,548 vessels with fitted SOx scrubber systems and additional 704 vessels that are on order with such systems. [17]

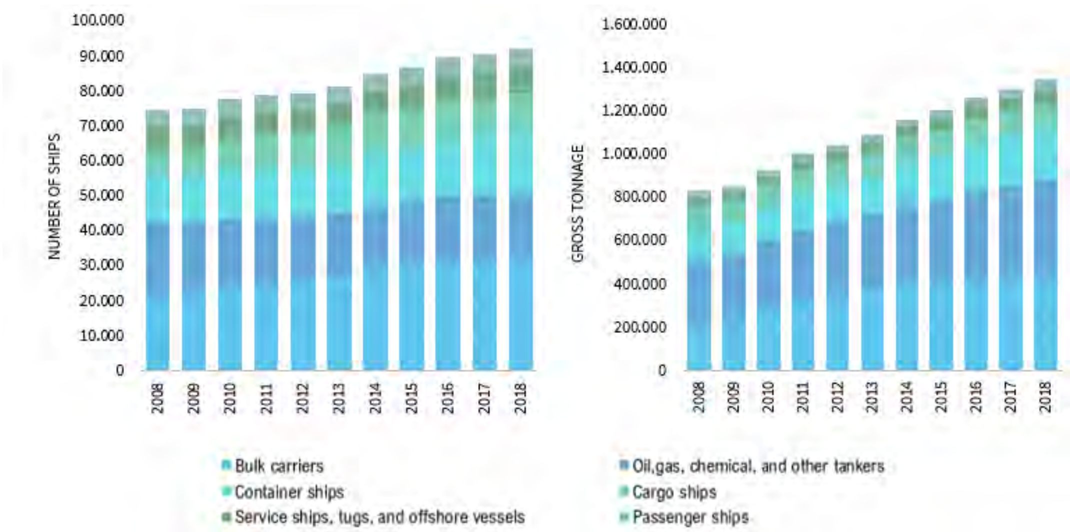
3.4 Who are the emitters?

The lifetime of ships (on average 30 years) highlights the urgency of enrolling hydrogen as a fuel as soon as possible. Due to the long lifetime of vessels, fleet renewal takes a long time, and therefore the transition to alternative fuels needs to start now to avoid that fossil-fuelled ships will still service global trade and EU-trade for decades to come.

The current global fleet is composed of 92,251 vessels as of 2018, according to Equasis, a data provider for the European Maritime Safety Agency. The numbers are dominated by small (< 500 GT) and medium (500 GT < x <25,000 GT) sized service ships, tugs, and offshore vessels, which accounted for 36% of all ships in 2018, followed by general cargo ships (20%) oil, gas, chemical, and other tankers (18%,) and bulk carriers (13%).

In terms of trends, the total number of ships had increased by 23% between 2008 and 2018 (CAGR of 2%). The share of general cargo ships in the global fleet has decreased from 28% in 2008 to 20% in 2018, while the share of service ships, tugs, and offshore vessels increased from 29% to 36% during the same period. Container ships are also increasing their share of the global fleet (from 10% in 2008 to 13% in 2018).

Figure 8. Number of ships and gross tonnage of world fleet by ship type (2008 – 2018)



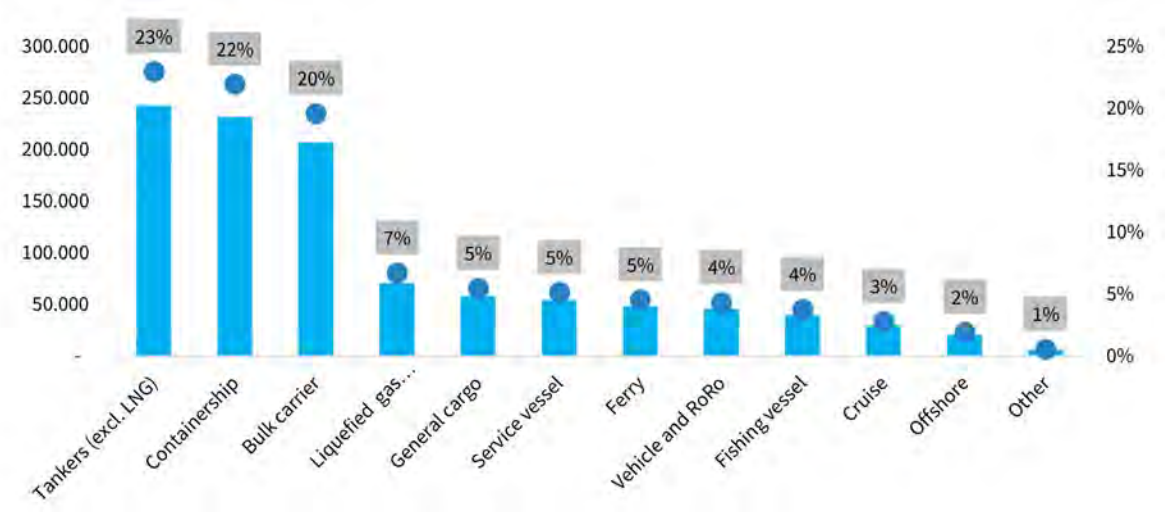
Source: Equasis.

Total gross tonnage (GT) of ships increased during the same period (2008-2018) by 62% - from 833,437 GT in 2008 to 1,350,508 GT in 2018. That corresponds to a compounded annual growth rate of 4.9% and reflects the trend of the growing size of ships in operation.

Bulk carriers accounted for more than one-third of all gross tonnage in 2018, closely followed by tankers representing 31% of total gross tonnage. Together with containerships with an 18% share, these three ship types constitute about 83% of the total gross tonnage of all ships in operation.

As a direct consequence of the number of those ships, according to the 4th IMO GHG study (see figure 7), tankers, containerships, and bulk carriers also contribute the most to global shipping emissions. **For example, in 2018 those three ship types were responsible for 65% of total shipping emissions.**

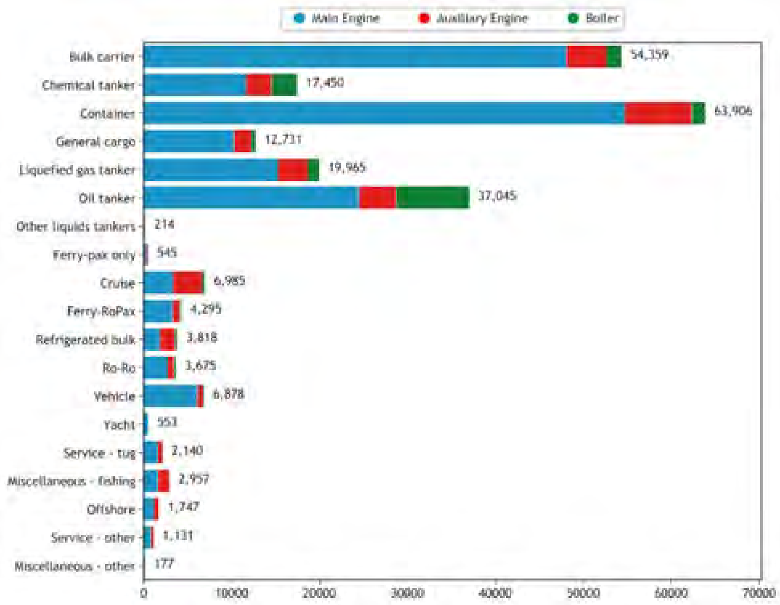
Figure 9. Total CO2 emissions by ship type and as % of global fleets' emissions in 2018 (thousands of tonnes)



Source: [10]

The primary source of energy demand (and related GHG emissions) across all ship types is coming from propulsion needs which is the primary demand for energy across all ship types. Albeit, that for some ship types (cruise ships, refrigerated bulk and miscellaneous fishing), total propulsion energy demand is approximately equivalent to total auxiliary and heat energy demand. [10]

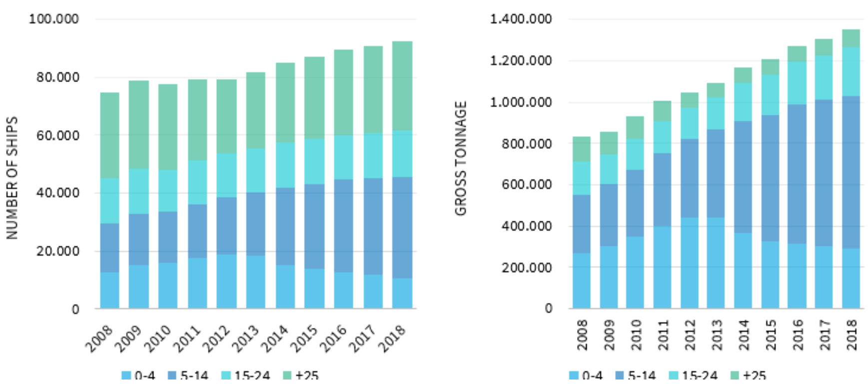
Figure 10. International, voyage-based allocation, HFO-equivalent fuel consumption (thousand tonnes), 2018, split by main engine, auxiliary engine and boiler. Highlighted values are in thousand tonnes.



Source: [10]

It is also interesting to look at the average age of ships. **Around half of all ships in operation are more than 15 years old, with around one-third being more than 25 years old.** The number of ships in the 0-4-year-old category has been decreasing, with its share having decreased from 17% in 2008 to 12% in 2018. This is the result of the gradual reduction in new orders as market accumulated excess capacity after freight rates fell in 2014 and 2015 [3]. The age distribution is different when analysing gross tonnage within different age categories. Here ships older than 15 years represent only around ¼ of the total, reflecting the growing size of new build ships.

Figure 11. Age distribution of ships by number of ships and gross tonnage



Source: Equasis

The long lifetime of ships is even more obvious if one would look at the average age of ships at the time they are scrapped. Containerships are being replaced most often with an average age of scrapped ships of 21 years. This is most likely a result of the trend of growing size of ships in this category, which makes the small vessels uncompetitive with the emergence of larger and larger ships. In the case of other big polluters, i.e. bulk carriers, the average age lifetime of a ship is more than 25 years. In the case of cruise ships, the average age of demolition was over 36 years, with the oldest vessel scrapped being in operation for 53 years. Ship lifetime is even higher for smaller ships, like general cargo ships, where it is close to 40 years on average, with the oldest two ships demolished during the last five years, having been built during the Second World War (a cement carrier built in 1945 and a general cargo ship built in 1943 after being in operation for 75 years).

Figure 12. The average age of ships scrapped between VIII.2016-VIII.2020, depending on ship type.

Source: own elaboration based on Clarksons World Fleet Register.

Taking these values into account, It becomes obvious that not only is decarbonization of the shipping sector needed, it needs to start now as ships ordered in the next years will impact emissions of the shipping sector for decades to come.

3.5 Alternative fuels deployments so far

Deployment of alternative fuels in shipping has been slow, and mostly centred around LNG with questionable GHG benefit

Although the drive towards decarbonization is nothing new, the shipping sector has so far been relatively unaffected by this global trend. Before the 2018 IMO initial strategy to reduce GHG emissions was introduced, the maritime sector was focusing most on adopting alternative fuels aimed at reducing air emissions, with GHG very much an afterthought.

Although the drive towards decarbonization is nothing new, the shipping sector has so far been relatively unaffected by this global trend. Before the 2018 IMO initial strategy to reduce GHG emissions was introduced, the maritime sector was focusing most on adopting alternative fuels aimed at reducing air emissions, with GHG very much an afterthought.
According to Clarksons Research, as of May 2020, the fleet of ships using alternative fuels consisted of 572 vessels including ships using LNG, methane, ethane, or biofuel as their primary fuel. This amounts to a meagre 0,6% of total vessels in operation. From one side, this is a result of the long lifetime of ships meaning that it takes a long time before new technologies can reach high market penetration. On the other hand, there is little doubt that the adoption of alternative fuels has been very slow.

In terms of the sector's GHG emissions, the impact of alternative fuels so far has been even smaller considering that the most common and popular alternative fuel is LNG - with 540 vessels in operation (almost 95% of hips using alternative fuels). LNG is most common among gas carriers with 385 vessels, passenger ferries and cruise ships with 56 vessels, and tankers with 33 vessels. Using LNG allows for a reduction of air pollutants most notably NOx although, its benefits with regards to GHG emissions remain questionable (see next chapter).

The utilization of LNG as fuel came with its proliferation as a means of transporting natural gas across continents which led to the development of the necessary LNG land infrastructure. In some cases, LNG can be an option to comply with existing emissions requirements (SOx, NOx, PM, CO2). LNG as a fuel can be competitive with distillate fuels and often does not require additional process technology, thus simplifying the installation/retrofit process.

While it has progressed, the lack of availability of LNG supply and distribution infrastructure continues to limit LNG's use in marine shipping. Besides availability and investment in LNG supply, distribution, and storage infrastructure, other challenges for LNG include the decreased range due to the lower energy content of LNG relative to HFO, MDO and reduced carrying capacity of LNG fuelled vessels due to LNG tanks having to be above deck [18].

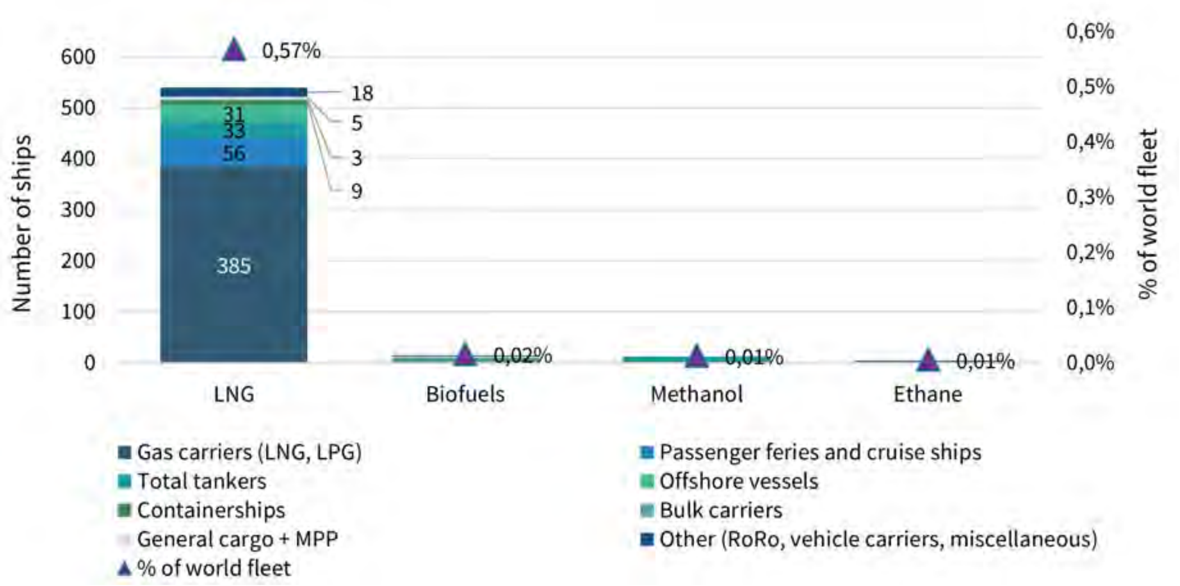
The second most common alternative fuel is other than methanol biofuels with a total of 15 ships, five of which are passenger ferries and cruise ships and three of which are containerships. Altogether they constitute 0.02% of the total fleet.

Biofuels and their potential have been explored for years by the automotive sector. Due to limited production sources, their availability, and subsequent scalability, their future is uncertain on a large scale. However, some of them provide an opportunity for blending with currently used fuels to reduce air pollutants as well as CO2 [18].

The third most common currently utilized alternative marine fuel is methanol used by 11 tankers and one passenger ferry. Methanol is a mature technology with the potential to save significant emissions as its combustion creates lower emissions during combustion. The life-cycle NOx emissions are lower by 55% compared to conventional marine fuels and methanol SOx emissions are 92% lower per unit of energy. Cost-wise, methanol is more economically feasible if a vessel spends most of its time in an ECA area and MGOs price is high [19].

As of May 2020, there were no hydrogen-powered vessels in Clarksons Research's World Fleet Register.

Figure 13. Adoption of alternative marine fuels in 2020



Source: Clarksons Research, Alternative Fuels Installations, May 2020.

3.6 Initiatives for the decarbonisation of the maritime sector

Drive towards decarbonisation of shipping is getting stronger both from the side of policymakers and governments as well as the industry itself

As demonstrated in the previous section, the adoption of alternative fuels has been relatively slow and the sector is slow in cutting GHG emissions. Compared to other sectors of the economy, it needs to be noted that several initiatives are addressing the issue of GHG emissions.

Except for the Initial IMO Strategy on reduction of GHG emissions from ships, these are mostly voluntary initiatives and as such, while it is important to demonstrate the viability of zero-carbon fuels and to build fuel supply chains, it is unlikely that on their own, they can result in large-scale uptake of low-carbon fuels.

IMO's 2050 GHG emission target [2]

In its role as the global standard-setting authority for the safety, security and environmental performance of international shipping, IMO has been at the forefront of environmental efforts in the maritime industry. Its objective, as with other initiatives, is to create a regulatory framework for the shipping industry that is fair and effective, universally adopted and universally implemented.

2 The following section is based on information gathered from the IMO website, mostly http://www.imo.org/en/OurWork/Environment/PollutionPrevention/AirPollution/Pages/GHG-Emissions.aspx and http://www.imo.org/en/MediaCentre/HotTopics/Pages/Reducing-greenhouse-gas-emissions-from-ships.aspx

IMO has been working to address greenhouse gas (GHG) emissions from ships since 1997 when it adopted “Regulations for the prevention of air pollution from ships” aimed at targeting SOx, NOx, and ozone-depleting substances, and other volatile organic compounds.

As part of these efforts, its Marine Environment Protection Committee (MEPC) adopted in 2011 during its 62nd session a package of technical and operational measures for all ships titled Regulations on energy efficiency for ships. These regulations entered into force on 1 January 2013 and apply to all ships of 400 gross tonnages. These measures represent the first global GHG reduction rule for the sector and consist of two parts:

- Energy Efficiency Design Index (EEDI) requires new ships to observe minimum mandatory energy efficiency performance levels which increase over time.
- Ship Energy Efficiency Plan (SEEMP) establishes a mechanism to be used by shipowners to improve the energy efficiency of both new and existing ships. The guidance on the development of the SEEMP incorporates best practices for fuel-efficient ship operation such as weather routing, trim and draught optimization, speed optimization, just-in-time arrival in ports, and others.

MEPC 70 in October 2016 approved a Roadmap for developing a comprehensive IMO strategy on reduction of GHG emissions from ships with planned adoption of an initial GHG reduction strategy in April 2018.

During IMO Assembly’s 30th session in December 2017, it adopted 7 new strategic directions including "Respond to Climate Change”. As a part of this direction, the IMO intends to “develop appropriate, ambitious and realistic solutions to minimize shipping's contribution to air pollution and its impact on climate change”.

The most important action taken by the IMO has been a resolution adopted during MEPC 72 on 13 April 2018 on Initial IMO Strategy on the reduction of GHG emissions from ships. The initial strategy represents a framework for the Member States, sets IMOs future vision for international shipping, specifies the ambition to reduce GHG emissions, and includes potential measures that can be adopted by member states. The strategy envisions that a revised strategy will be adopted in 2023.

The Initial Strategy identifies three means of reducing total GHG emissions from international shipping:

- Reducing ship carbon intensity by implementing further phases of the energy efficiency design index (EEDI) for new ships
- Reducing the carbon intensity of international shipping by at least 40% by 2030, pursuing efforts towards 70% by 2050, compared to 2008
- Achieving peak of GHG emissions from international shipping and reducing the total annual GHG emissions by at least 50% by 2050 compared to 2008 whilst pursuing efforts towards phasing them out

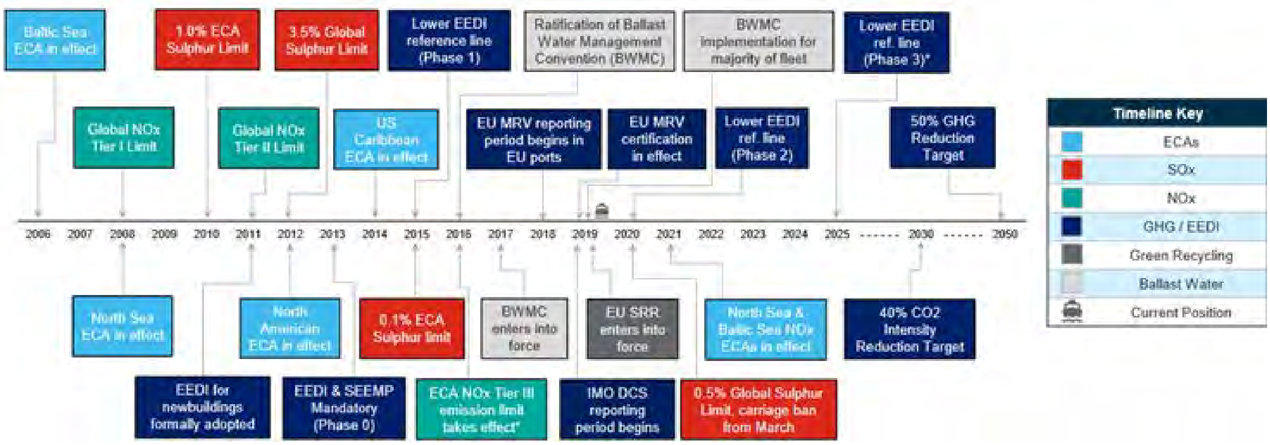
In October 2018, IMO Member States approved a Programme of follow-up actions of the Initial Strategy up to 2023. These include:

- Candidate short-term measures of various degrees
- Candidate mid/long term measures
- Impacts on states
- Fourth IMO GHG study
- Capacity building,
- Technical cooperation
- Research and development
- Follow-up actions towards the development of the revised strategy
- In its subsequent meetings, MEPC monitors and amends the adoption of the proposed activities above.
-

The Fourth IMO GHG Study was submitted to the Marine Environment Protection Committee (MEPC) in July 2020, as document MEPC 75/7/15.

Figure 11 below demonstrates the IMO's 50% reduction compared to the 2008 objective using data from the Joint Research Center's EDGAR database. The required annual GHG emission decrease is 2.02% between 2015 – 2050 to attain the same level that international shipping emissions were last in 1987. So, the objective is to decrease emission growth of the last 33 years over the next 30 years.

Figure 14. Environmental regulations affecting the shipping sector



Source: Clarksons Research, September 2019, "EEDI phase 3 requirements bought forward to 2022 for gas carriers, general cargo ships and containerships.

Poseidon Principles – financing

https://www.poseidonprinciples.org

"*The objective is to organize a group of aligned and committed financial institutions to take ownership of a set of principles to integrate climate considerations into lending decisions in ship finance, consistent with the climate-related goals of the IMO.*"

Similar to the role that responsible investment/asset management firms played in the current investment transition towards ESGs, financing that considers climate objectives can have a transformative effect on the shipping industry.

The year following IMO's Initial strategy on GHG emissions, a group of financiers joined to form a new global framework for integrating climate considerations into lending decisions to promote international shipping's decarbonization. Titled Poseidon Principles and established in June 2019, it comprises a group of financial institutions committed to adapt their lending practices to contribute to IMO's climate-related goals as expressed in the 2018 IMO initial strategy on GHG emission reduction.

The Principles provide an opportunity for financiers to divert financing away from the least efficient and most polluting vessels towards more efficient ones. By forcing ship owners to use more efficient ships, they both contribute to GHG reduction as well as shrinking the cost difference between the current fleet and new fuels and technologies.

As of now, 18 financial institutions signed up to the Poseidon Principles. They represent a bank loan portfolio to the global shipping industry of approximately $150 billion – more than a third of the global ship finance portfolio. The signatories are almost exclusively European banks with only Citi representing North America and Sumitomo Mitsui Trust Bank representing Asia.

The scope of the Poseidon Principles is intended to evolve to include other issues where financial institutions can improve maritime industry behaviour and its contribution to society.

As a member of PP, signatories will:

- Publicly acknowledge their involvement in Poseidon Principles
- Publish an annual report on climate alignment of their shipping portfolio
- Publish their overall climate alignment in a relevant institutional report such as the annual report

The four Poseidon Principles are:

- Principle 1: Assessment of climate alignment
- Principle 2: Accountability
- Principle 3: Enforcement
- Principle 4: Transparency

Poseidon Principles will publish annually all climate alignment scores by respective signatories. The first report is expected by the end of 2020.

Signatories of the Principles include ABN Amro, Amsterdam Trade Bank, BNP Paribas, Bpifrance, Citi, Credit Agricole CIB, Credit Industriel et Commercial, Credit Suisse, Danish Ship Finance, Danske Bank, DNB, DVB, Export Credit Norway, ING, Nordea, Société Générale, Sparebanken Vest and Sumitomo Mitsui Trust Bank.

Getting to Zero Coalition

GLOBAL MARITIME FORUM FRIENDS of OCEAN ACTION WORLD ECONOMIC FORUM

https://www.globalmaritimeforum.org/content/2019/09/Getting-to-Zero-Coalition_Industry-Roadmap.pdf

Announced date: September 2019 – UN Climate Action Summit NYC

"The ambition of the Getting to Zero Coalition is to have ***commercially viable ZEVs (zero-emission vessels)*** *operating along deep-sea trade routes by 2030, supported by the necessary infrastructure for scalable zero-carbon energy sources including production, distribution, storage and bunkering."*

Getting to Zero Coalition is a partnership between the Global Maritime Forum, the Friends of Ocean Action, and the World Economic Forum. It is a moon-shot initiative by a coalition of member companies from across the maritime industry that are committed to decarbonizing shipping by ensuring that commercially viable zero-emission vessels are in operation by 2030. Given the complex nature of the objective, they stress the importance of a broad range of stakeholders working together as well as strong private sector leadership that will strongly support local, national, and international policies.

Phase 1: 2019-2020 - Building and expanding the Coalition base

- Broad-based cross-industry coalition with global reach committed to ZEV 2030
- Shared knowledge base outlining the pathway with the most promising fuel options
- Results of the first demonstration projects

Phase 2: 2021-2023 - Developing the solutions and the enabling environment

- Externally accepted notion of a commercially viable ZEV by 2030
- ZEV demonstrations achieved through flagship pilot projects
- Developed access to finance to support and de-risk the initial investments
- Identified business models and market drivers to generate market-based incentives involving customers, finance and other stakeholders
- Engaged ports and established trade corridors for ZEV operations

Phase 3: 2024-2027 - Testing and putting the enabling environment in place

- Established policy environment making commercial investments in ZEVs bankable
- Demonstrated safety of large deep-sea vessels running on the new maritime fuels, and first operational trading corridors with easy access to zero-emission fuels
- Substantial increase in the production of the new maritime fuels
- New business models, economic incentives, and finance available for ZEV deployment

Phase 4: 2028-2030 - Getting ready for roll-out

- First commercially viable ZEVs deployed on key trade corridors
- Expanded production capacity of zero-carbon energy sources to match the rise of the ZEV fleet
- ZEVs having become the preferred option to replace existing ships

MAERSK's 2050 plan - individual corporate target

MAERSK

One of the first individual corporate initiatives in the shipping industry, Maersk decided to reach corporate carbon neutrality by 2050. It outlines the need for acceleration and innovations to make ZEVs commercially viable by 2030.

Maersk is a leader in shipping sustainability having achieved a 41% relative reduction in CO_2 emissions from its activities in 2019 compared to 2008.

The Company plans to invest significant resources for innovation and fleet technology to improve the technical and financial viability of decarbonised solutions. It will rely on other industry players to conduct their R&D efforts as well as on cooperation with other industry players through the Getting to Zero Coalition.

Sustainable Shipping Initiative

https://www.ssi2040.org/wp-content/uploads/2017/01/SSI_fullreport.pdf
https://www.ssi2040.org/what-we-do/how-we-operate/

Founded in 2010, SSI identifies future challenges for the maritime shipping industry and it seeks to address them together with its members. Its members comprise the entire shipping value chain including charterers, shipowners, shipyards, ports, port operators, banks, finance and insurance providers, and others. World Wildlife Fund and Forum for the Future, NGOs, also provide a perspective to the Initiative on how can shipping can contribute to a more sustainable future.

The three main challenges identified by the SSI include:

- Navigating a changing economic context
- Increased scrutiny, high expectations
- The future of energy and climate change
- Exploring the role that volatile oil prices, climate change pressures will play in the future and how companies can gain a competitive advantage by investing in energy efficiency and new fuels

SSI addresses the identified challenge through:

- Demonstrating leadership through its members' sustainability initiatives
- Combining members' expertise to address specific challenges that require co-ordination, innovation, or scale
- Driving the debate on sustainability issues in the shipping industry to encourage the development of long-term strategic perspective among its members

Clean Cargo Working Group – data gathering and sub-sector industry forum

https://static1.squarespace.com/static/5b3f37f489c17230345b5f15/t/5c935bd74e17b65e8981a5da/1553161178784/bsr-ci-ccwg.pdf

"Clean Cargo members share a vision of a shipping industry that is a responsible part of sustainable supply chains and that supports clean oceans, healthy port communities, and global climate goals."

Clean Cargo is a business initiative founded in 2002 that gathers major brands, cargo carriers, and freight forwarders dedicated to reducing the environmental impacts of their operations and promoting responsible shipping practices. It achieves its objective through tracking and benchmarking the environmental performance of vessels. Since its launch, its methodology has become the standard for the container shipping sector.

It comprises emissions data from 23 of the world's leading ocean carriers that represent approximately 85% of global ocean container capacity.

Clean Cargo reports that its members have reduced their CO2 emissions per TEU-km by 35% since 2009. It also allows shipping customers to compare and take into consideration carriers' environmental performance when procuring shipping services.

Clean Shipping Index – labelling system

https://www.cleanshippingindex.com/

Launched in 2010, Clean Shipping Index is an independent labelling system of vessels' environmental performance that also serves as a comparison tool between different vessels or fleets.

The scoring system is based on a self-assessment by shipowners whose data is then independently verified. It provides different degrees of environmental friendliness which results in different benefits in terms of reduced port and fairway fees. It also incentivizes ship owners to choose more sustainable shipping alternatives.

The aim is to provide a competitive economic advantage for environmental-friendly ships.

World Ports Sustainability Program

The International Association of Ports and Harbors launched in 2017 the World Ports Sustainability Program that aims to enhance and coordinate ports' sustainability efforts and promote cooperation to contribute to UN SDG goals. The program aims to assist ports with engaging business, governmental, and societal stakeholders to develop projects that create sustainable value for ports' local communities and regions.

It intends to achieve this goal through the following actions:

- Establishing and maintaining a global library of best practices and projects
- Fostering collaboration among ports and other partners to develop new projects
- Regular reporting about the sustainability performance of the global ports

The program operates in the following five areas

- Climate and energy: port community actors will collaborate to facilitate the reduction of CO_2 emissions from shipping, port and landside operations in addition to other related activities such as contributing to the energy transition, improving air quality, and stimulating the circular economy.
- Resilient infrastructure
- Safety and security
- Governance and ethics
- Community outreach and port-city dialogue

Green Award

It was established in 1994 and is a non-profit organization run by the Green Award Foundation in the Netherlands. The organization audits and provides certificates for both sea and inland shipping vessels as well as to companies that go above and beyond the industry standards in terms of safety, quality and environmental performance. It also acts as a quality mark and brings benefits to its holders from participating entities. As of 2020, it has certified over 900 inland and sea-faring ships. 140 participating ports, financing institutions, and maritime service providers offer discounts or other benefits for certified vessels. It has more than 30 participating countries across all continents.

Maritime Industry Decarbonisation Council

https://midc.be/about/

A think-tank was set up in 2016 by the Royal Belgian Shipowners' Association (RBSA) to structure and assess potential short, medium, and long-term technical measures for reducing GHG emissions.

The council assesses decarbonisation options for both existing and new ships, emphasising the current fleet as there are limitations to the GHG reduction potential of existing ships. One of the key questions it tries to answer is to what extent can energy efficiency improve the existing fleet. During its measure evaluation, it focuses on CO_2 reduction potential, cost, technical maturity, and scalability.

ZESTAs - Zero Emissions Ship Technology Association

http://zestas.org/#home

Zero Emission Ship Technology Association was launched in 2019 to serve as a common voice advocating for zero-emission ship technologies. It is the first zero-emission maritime trade association. It aims to inform and influence the shipping industry and policymakers about the availability, opportunities, and needs of the emerging zero-emission shipping.

It seeks to ensure that commercial shipping reduces its emissions in line with 1.5 degrees by:

- Informing the shipping industry about available zero-emissions ship technologies (ZEST);
- Educating and influencing regulators and policymakers to promote ZEST through legislation at national and international levels;
- Developing a means of effective collaboration between the various ZEST companies;
- Besides, ZESTA also plans to develop a database of ZEST companies and technologies as well as assist its members with finding projects and research financing for zero-emission ship projects.

4. Hydrogen as a pathway to the decarbonisation of shipping

4.1 Hydrogen as a maritime fuel

If produced from nuclear or renewable energy, hydrogen enables reduction of 100% Well-to-Wake GHG emissions

Hydrogen is an energy carrier and a widely used chemical commodity. It is a colourless, odourless and non-toxic gas. For maritime use, it can be stored either in liquid form, as compressed gas, or chemically bound.

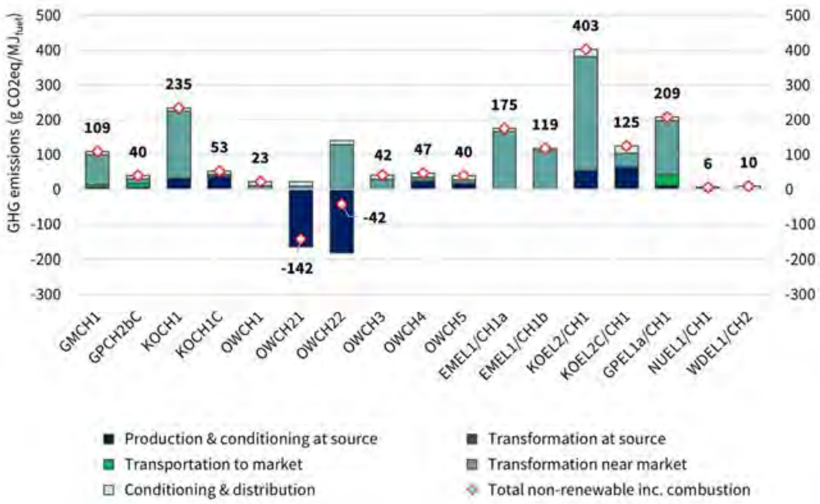
Hydrogen as a fuel can be used in multiple ways either in fuel cells, as a dual fuel mixture with conventional fuels, or as a replacement in the combustion process [20]. The highest efficiency can be achieved in fuel cells (with efficiency ranging between 50 and 60% and potentially even higher with heat recovery), while adapted combustion engines have an efficiency between 40 and 50%. In neither of those cases does conversion of hydrogen into energy (Tank-To-Wake) generate any emission other than water. Total Well-To-Wake (WTW) emissions are therefore entirely dependent on the way hydrogen was produced.

If produced from nuclear or renewable energy, hydrogen enables reduction of up to 100% Well-to-Wake GHG emissions.

Furthermore, blending with conventional fuels improves combustion and emission properties while reducing GHG emissions [21]. Even a 50/50 mixture of heavy fuel oil and hydrogen could reduce CO2 emissions by up to 43% per ton-kilometre [22] [20].

Hydrogen produced with nuclear energy is a zero-emission fuel as well. If combined with Carbon Capture and Storage (CCS), hydrogen produced from natural gas or even coal can have as low a carbon footprint as hydrogen produced via reforming of biogas from municipal organic waste, maize or sewage sludge. If upgraded biogas from wet manure would be used as feedstock for steam reforming, total hydrogen WTW GHG emissions would be negative. Unfortunately, as of 2019, over 90% of the hydrogen produced in the EU is produced from fossil fuels without CCS [23] [24].

Figure 15. WTT GHG hydrogen footprint for different hydrogen production pathways



Note:

- ***GMCH1*** *- EU-mix natural gas supply, transport to EU by pipeline (1900 km), transport inside EU (500 km), distribution through high-pressure trunk lines and low-pressure grid, steam reforming at retail station, compression to 88 MPa.*
- ***GPCH2bC*** *Piped natural gas supply, transport to EU by pipeline (a, 4300 km to EU border and 700 km inside EU) or Southern Asia / Middle East (b, 4000 km), distribution through high pressure trunk lines, central large scale reformer with CCS, hydrogen pipeline, compression to 88 MPa at retail station.*
- ***KOCH1 / KOCH1C*** *- EU-mix hard coal without/with CCS, hydrogen pipeline transport, compression at retail site.*
- ***OWCH1*** *- Upgraded biogas from municipal organic waste sent to onsite SMR, Hydrogen compression to 88 MPa at retail site. Closed digestate storage.*
- ***OWCH21*** *and* ***OWCH21*** *Upgraded biogas from wet manure sent to onsite SMR. Digestate storage closed (21) or open (22)*
- ***OWCH3*** *- Upgraded biogas from sewage sludge sent to onsite SMR. Closed digestate storage*
- ***OWCH4*** *- Upgraded biogas from maize (wole plant) sent to SMR. Closed digestate storage*
- ***OWCH5*** *- Upgraded biogas from double cropping (barley/maize) sent to SMR. Closed digestate storage*
- ***EMEL1/CH1a and EMEL1/CH1b*** *- EU-mix electricity supply (based on actual averages), High voltage. (1) on site electrolysis, (2) central electrolysis with hydrogen pipeline transport. Hydrogen compression to 88 MPa.*
- ***KOEL2/CH1 and KOEL2C/CH1*** *- Hard coal (EU-mix), IGCC with or without CCS. On site electrolysis, hydrogen compression to 88 MPa.*
- ***GPEL1a/CH1*** *- Natural gas: CCGT, natural gas supplied over 5000 km pipeline (Russia). Electrolysis: on retail site, hydrogen compression to 88 MPa.*
- ***NUEL1/CH1*** *- Electricity from nuclear energy. Electrolysis: on retail site, hydrogen compression to 88 MPa.*
- ***WDEL1/CH2*** *- Electricity from wind energy. Central electrolysis, hydrogen pipeline transport, hydrogen compression to 88 MPa.*

Source: [23].

Hydrogen has high specific energy at 120 MJ/kg or 33,3 kWh/kg, approximately three times the energy density of HFO, but a low energy density of 10.8 MJ/m3 in gaseous form, 5,040 MJ/m3 when compressed, and 8,500 kg/m3 in liquid form. The volumetric density of liquefied hydrogen is at 71 kg/m3, and it is only 16% of the density of marine gas oil. As a result, the liquified hydrogen's energy density is approximately five times the volume of the same amount of energy stored as marine gas oil. If stored as a compressed gas at 350 bar, its volume is 7.5 times the volume of the same amount of energy stored as marine gas oil. **The relatively low volumetric energy density of hydrogen is, next to high production costs, the biggest techno-economical barrier to large-scale adoption of hydrogen in maritime applications.**

Hydrogen is not toxic, corrosive, radioactive, foul-smelling, water-polluting or even carcinogenic. Hydrogen can, however, displace atmospheric oxygen and, as such, have an asphyxiating effect. Its most obvious safety-related feature is its high flammability and the broad ignition limits in hydrogen-air mixtures from 4 to 75-77%. In ambient conditions, hydrogen is a combustible gas and – as such – if released, can form explosive mixtures with air. Since hydrogen is lighter than air, it escapes upwards. Therefore, hydrogen should either be stored in the open air or, if in enclosed spaces, with good aeration and ventilation. [25]

Table 3. Physical and Combustion Property Values for Hydrogen and Methane

Quality	Hydrogen	Methane
Molecular Weight	2.016	16.043
Density of Gas at NTP, [kg/m3]	0.08376	0.65119
Temperature to Achieve NTP Neutral Buoyancy in Air (1.204 kg/m3), [K]	22.07	164.3
Normal Boiling Point (NBP), [K]	20	111
Liquid Denisty at NBP, [g/L]	71	422
Enthalpy of Vaporization at NBP, [kJ/mole]	0.92	8.5
Lower Heating Value, [MJ/kg]	119.96	50.02
Limits of Flammability in Air, [vol%]	4 – 75	5.3 – 15
Explosive Limits in Air, [vol%]	18.3 – 59.0	6.3 – 13.5
Minimum Spontaneous Ignition [Pressure, bar]	~41	~100
Stoichiometric Composition in Air, [vol%]	29.53	9.48
Minimum Ignition Energy, [J]	0.02	0.29
Flame Temperature in Air, [K]	2318	2148
Autoignition Temperature, [K]	858	813
Burning Velocity in NTP Air, [m/s]	2.6 – 3.2	0.37 – 0.45
Diffusivity in Air, [cm2/s]	0.63	0.2

Source: [26].

Yet even though its application in the maritime sector is relatively novel and safety-related issues should not be underestimated, it should also be noted that the fertilizer and oil refining industries, which consume millions of tonnes of hydrogen every year, had been handling hydrogen for over a century with an excellent safety record. ISO Technical Report 15916 (2015) contains international guidelines for the safe handling and storage of gaseous and liquid hydrogen. Safety requirements for specific applications are also laid down in other ISO standards referenced in that report. They include, e.g., ISO 19880 (2016), which describes safety and performance requirements for compressed hydrogen refuelling stations for passenger cars and other motor vehicles. [25] [27]

Furthermore, the 50-year safety record of transporting LNG throughout the world is excellent and since liquid hydrogen and LNG are very similar in their physical and combustion properties, minor augmentation of the proven and effective international regulations for LNG transport will enable regulated and safe use of hydrogen fuel cell technology in maritime applications [26].

The growing importance of hydrogen and hydrogen-based fuels for the energy transition is also evident among maritime sector participants. A survey of shipping stakeholders conducted by UMAS and Lloyd Register yielded that 85% of respondents are concerned about upstream emissions and 80% agree that Zero Emission Vessels (ZEV) are needed. The respondents identified hydrogen, biofuels, and batteries as the most important fuel options in decarbonization [28].

A recent survey from a classification society ABS revealed that 60% of respondents see ammonia and hydrogen as the most attractive fuels for shipping in the long term [29]. Yet, at the same time, another ABS survey has revealed that two-thirds of respondents admitted to having no decarbonisation strategy in place to meet IMO’s 50% GHG reduction by 2050 target. [30]

A 2018 study by the International Transport Forum, a part of OECD, calculates that in the case of 80% carbon reduction in maritime shipping, hydrogen and ammonia will hold around 70% of the fuel market. [20]

4.2 Sector coupling

Deep decarbonisation across all sectors of the economy is improbable and prohibitively expensive without hydrogen.

The attractiveness of hydrogen as a solution for the maritime sector comes not only from the fact that it is a zero-emission fuel and from its excellent safety record but is also connected to the fact that hydrogen offers a number of potential synergy opportunities between the shipping sector, the industrial base in and around port areas and the energy system as a whole.

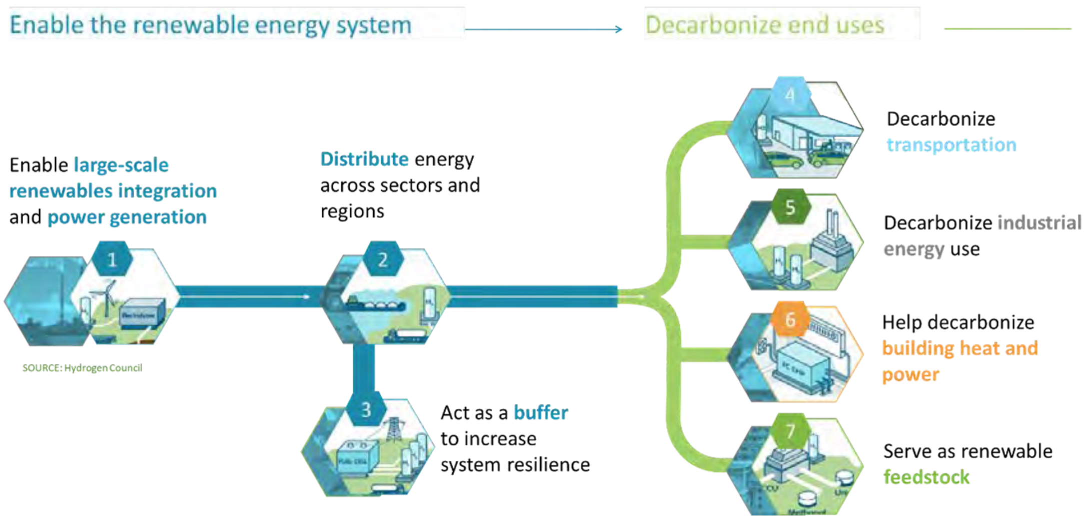
Hydrogen has a much broader role to play in the decarbonisation of the economy than just as a zero-emission fuel. Hydrogen is the only sufficiently available and scalable technology for sector coupling which is essentially energy system optimization through production and consumption management in different sectors. According to the European Commission (DG Energy), sector coupling is “a strategy to provide greater flexibility to the energy system so that decarbonisation can be achieved in a more cost-effective way”. [31]

Hydrogen allows electricity to be converted and stored, even seasonally, as a gas, it facilitates energy distribution across sectors and regions, serves as a buffer for renewables, and its applications provide technological means to decarbonize power, transport, buildings, and industry sectors. It provides a versatile, (ideally) clean, and flexible energy vector for the required transition and is one of the several essential levers that make large-scale integration of renewables possible. It can convert generated power into a usable and transportable molecule, stored, and transported t to end-use sectors. Hydrogen and hydrogen-based molecules will be utilized in the ongoing energy transition the following way:

- **Industry** - Hydrogen from renewables is one of the few options to replace fossil fuel-based feedstocks in various industrial emission-intensive applications. Achievability is based on the scalability of green hydrogen, hydrogen’s overall economic competitiveness, and the adaptability of currently used industrial processes.
- **Heating and stationary power** - Complete and direct electrification of heating is unlikely due to high power system requirements and associated grid investments. Therefore, grid injected hydrogen and resulting gas hydrogen blend has the potential to reduce natural gas emissions from heating. One of the key advantages of hydrogen in heating is hydrogen’s ability to be stored long term and on a large scale similar to the current natural gas storage systems. It enables the energy systems to manage large oscillations in demand as well as provide inter-seasonal storage. In stationary power, hydrogen can be blended with natural gas for combustion in power plants or used in fuel cells. Both cases utilize the previously mentioned hydrogen’s benefits in storage and system flexibility.
- **Transport** - If powered by green hydrogen, fuel cell electric vehicles (FCEVs) provide low-carbon mobility options with a driving range and refilling comparable to ICEs and serve as complementary mobility solutions to battery-electric mobility solutions (BEVs). They primarily have potential in markets that are currently underserved by battery solutions such as certain bus routes, taxis, long-range road transport, trains, maritime solutions, and aviation.
- **Energy Storage** - The previously mentioned sectors, as well as gas infrastructure and overall hydrogen supply chain, can provide short-term flexibility for the power system as well as making electricity, gas, or heat systems a source of energy storage to decouple final energy demand from renewable electricity production. [32]

In essence, deep decarbonisation across all sectors of the economy is improbable and prohibitively expensive without hydrogen.

Figure 16. Many roles of hydrogen in energy systems decarbonisation.



Source: Hydrogen Council.

This energy system integrating the role of hydrogen has been reflected in a number of recent studies and communications by the European Commission. For example, an EU document from November 2018 titled “A Clean Planet for all: A European strategic long-term vision for a prosperous, modern, competitive and climate neutral economy”,[3] which sets out a vision for a climate-neutral EU, highlights hydrogen’s future role as an energy carrier in heating, transport, and industry, as a feedstock for industries such as steel and chemicals that are difficult to decarbonize, and as energy storage in the power sector through Power to X (PtX) technologies to accommodate new variable renewable energy resources.

The European Green Deal from December 2019[4] is the EU’s roadmap for making the EU's economy sustainable. It specifies its plans to transform the European economy to achieve a sustainable future while securing Europe’s technological prominence in future low-carbon technologies. In addition, the Green Deal mentions the importance of hydrogen in r refocusing more efforts into hydrogen research, its priority deployment in industrial applications, and the need for proper regulatory alignment for hydrogen networks.

In its 2018 Future of Hydrogen landmark report, the International Energy Agency (IEA) identified hydrogen as an enabler of renewable power generation, means of decarbonisation for hard to abate sectors and a versatile molecule to store and transport renewable energy not only in Europe but also between continents. Hydrogen has to tackle its challenges which are currently high costs for low-carbon hydrogen production, slow development of hydrogen infrastructure, its fossil fuel origins as most of it is supplied from natural gas and coal today, and regulations limiting its development. [33] The report concluded that the potentially critical role of hydrogen is increasingly recognised around the world.

3 COM/2018/773 final
4 COM/2019/640 final

Similar to IEA, the International Renewable Energy Agency has also identified hydrogen as the missing link in the energy transition in its 2018 Hydrogen from renewable power report. It identified similar conclusions to the IEA of hydrogen potential to decarbonise hard to abate sectors such as industry, heating, transport, its ability to integrate variable renewable energy, and storage capabilities. [34]

An April 2020 study from consulting firm Navigant on the integration of North Sea offshore wind up to 2050 also heavily features hydrogen as an enabler of large-scale renewable deployment and the most cost-efficient means of integrating an extra 180 GW of offshore wind in the North Sea. [35]

Finally, the role of hydrogen in ongoing decarbonisation efforts has also been recognised in the EU Energy System Integration Strategy[5] and then in the EU Hydrogen Strategy,[6] announced in July 2020, which sets out a target of at least 10 million tonnes of clean hydrogen production in the EU by the end of 2030

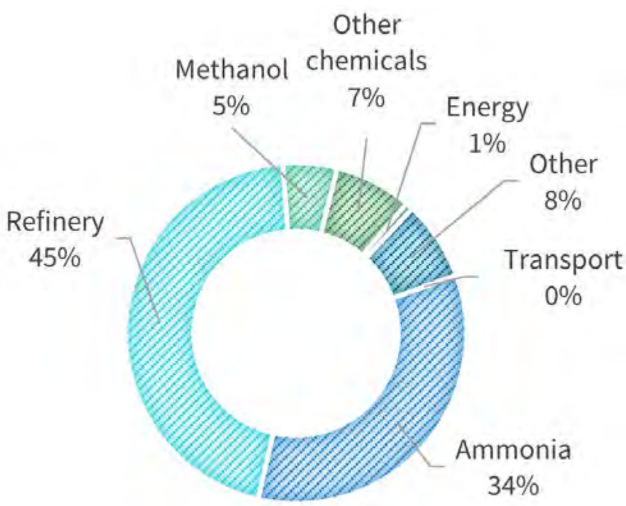
4.3 The central role of ports

Maritime ports are set to become key hubs of the emerging hydrogen economy

From the point of view of the maritime sector, it is important to point out the central role that the maritime ports have in the transition towards the hydrogen economy.

Already today, a large portion of hydrogen industrial production and consumption takes place in ports or close proximity to ports. The biggest hydrogen consumers come from the oil refining, ammonia and chemical industries, which combined use around 90% of all hydrogen produced each year in the EU, and quite a lot of those facilities are located in EU ports.

Figure 17. Structure of hydrogen consumption by sector, 2018



Source: [24].

5 COM(2020) 299 final
6 COM(2020) 301 final

Just five industrial hubs in the Belgian and Dutch ports (Antwerp, Zeeland, Rotterdam, IJmond and Delfzijl) have a combined local hydrogen demand of 1.7 Mt per year, which is equal to around 20% of total EU consumption today [24]. Most of that hydrogen is also produced locally, usually from natural gas through steam methane reforming.

Figure 18. Location of hydrogen production plants in Europe

Source: [24].

This opens two important opportunities. First, as grey hydrogen will gradually need to be replaced with renewable or low carbon hydrogen, having a large hydrogen demand centre in port makes it possible to develop a clean hydrogen supply chain for shipping already at a large enough scale to benefit from the economies of scale, even if the demand from hydrogen for shipping would take time to grow. This would be further strengthened by the fact that many port areas are also hosting other industrial facilities from the so-called "hard-to-abate" sectors like the steel industry, which are also increasingly looking at hydrogen as an option for decarbonisation.

Secondly, existing grey hydrogen production plants could be retrofitted with carbon capture and storage (CCS) potentially offering a local supply of low carbon hydrogen, limiting the need for investments in hydrogen storage and distribution infrastructure.

Furthermore, hydrogen can also be used as fuel for most material handling vehicles used in port terminals to decarbonise port operations and further increase demand for clean hydrogen. This has already been successfully demonstrated by the H2Ports project, funded by the Fuel Cell and Hydrogen Joint Undertaking (FCH JU). The project is located at the Port of Valencia, where two innovative solutions based on fuel cell (FC) technologies and hydrogen are tested.[7]

7 A Reach stacker in MSC Terminal Valencia and a Yard Tractor in Valencia Terminal Europa (part of the Grimaldi's group). More information at www.h2ports.eu.

Figure 19. H2Ports project

Source: www.h2ports.eu.

The falling prices of offshore wind are making this renewable energy technology potentially the cheapest source of renewable hydrogen, especially in northern parts of Europe where solar PV is less competitive, making ports ideally placed to become large renewable hydrogen production centres. It is also increasingly likely that Europe will not be able to produce enough hydrogen to cover the entire future demand locally. A potential solution might be to import clean hydrogen by ships from North Africa, Chile or other countries with favourable wind/solar resources. Here too, ports are set to benefit.

Therefore, it is becoming clear that maritime ports are set to become key hubs of the emerging hydrogen economy.

4.4 What are the alternatives?

While there are multiple other solutions, hydrogen and e-fuels made from hydrogen are the only that are both sustainable and scalable

Although this report focuses exclusively on hydrogen and hydrogen-made synthetic fuels, it should be noted that other potential options are being considered for the decarbonisation of the shipping sector.

The most commonly considered alternative fuels/propulsion systems in shipping are LNG, batteries, and biofuels, but each of them comes with its own set of advantages and challenges.

Electrification

Similar to using hydrogen as a fuel, battery technology offers a TTW zero-emission solution. On the other hand, well-to-Wake emissions depend on the carbon footprint of the national/regional electricity grids that are used to charge the batteries.

Because of the high energy efficiency of electric motors (up to 99%), high efficiency of energy storage in batteries and relatively low energy losses for AD/DC and DC/AC conversions, the biggest advantage of direct electrification of waterborne transport is certainly the fact that it is by far the most energy-efficient option.

The first fully electric vessel, MF Ampère, has been in service between Lavik and Oppedal on the west coast of Norway since 2015 [36]. According to Clarksons Research, as of June 2020, there were 16 vessels in operation with battery-electric propulsion. All of them were small ferries or catamarans below 3,000 GT. There are also 29 further battery-electric vessels on order, with the current building date between 2020 and 2023. Besides pure battery-electric ships, there were also 101 hybrid battery-electric vessels (with a further 68 on order), which are using batteries only as a power source for manoeuvring in ports or peak load shaving.[8]

Yet, despite these initial deployments, batteries face a number of important challenges that are limiting their usefulness for shipping decarbonisation, especially when it comes to larger vessels.

One issue faced by the direct electrification option is related to the fact that while there are no TTW emissions, the overall carbon footprint of battery-powered vessels depends on the carbon intensity of the grid electricity used for battery charging. While there are some countries in the EU where the carbon intensity of the grid is low enough for that not to be an issue, there is still quite a number of those, most notably Estonia and Poland, where battery-electric vessels would result in a net increase in GHG emissions. In the long term, this issue should solve itself by the expected decarbonisation of power generation in the EU, but in the meanwhile, the climate benefit would be limited.

Another key challenge is the extremely low energy density of batteries. As a recent study by the US Sandia National Laboratory has shown [37], for most ship types, space and mass requirements are so large that it is impossible to fit a required battery storage system that would be enough even for a single one-way voyage.

Figure 20. Comparison of space and weight requirements of different zero-emission systems for a large containership (example of Emma Maersk)

Source: own elaboration based on: [37].

8 Clarksons Research, World Fleet Register, Accessed 03/06/2020

Finally, even if, through some future technological breakthrough, the energy density problem could be overcome, there would still be an issue with the provision of the required charging infrastructure in ports. The size of the challenge can be best seen in the example of Ro-Pax ferries. A vessel of this type operating on a line like Gdynia (PL) – Karlskrona (SE) would need around 200 MWh of energy for a single one-way trip. Considering that ferries usually are unloaded/loaded within 1.5 – 2.0 hours, to charge the batteries within the available time, the onshore power supply (OPS) system would need the power of at least 100 MW. There are not many ports in the EU capable of doing that. Furthermore, considering that this is just power required for a single ship, it becomes clear that **while batteries are likely to be adopted for some use cases, especially short sea shipping, their low energy density, high requirements for onshore power supply, and charging times will continue to limit their proliferation among other medium-to-long distance applications.**

Biofuels

In terms of technology readiness and cost, biofuels appear as one of the most attractive ZEV solutions and flexible alternatives to current marine fuels. Biofuels can be either blended with conventional fuels or used as a drop-in fuel without changes to the existing infrastructure and assets, requiring minimal adjustments to machinery and storage. As a result, they are often touted as the ideal replacement for fossil-based marine fuels. However, biofuels face at least two significant challenges related to their sustainability and availability.

In the case of the most commonly used first generation, it is clear that many types of crop-based biofuels are worse from a climate impact perspective than the fossil fuels they are replacing. This is mostly due to indirect land-use change (ILUC).

When existing agricultural land is turned over to biofuel production, agriculture must expand elsewhere to meet the existing (and growing) demand for food and animal feed crops. This happens at the expense of forests, grasslands, peatlands, wetlands, and other carbon-rich ecosystems and, in turn, results in substantial increases in greenhouse gas emissions. ILUC is a key factor that shows why crop biofuels are not a decarbonisation option for transport. Issues relating to impacts on biodiversity, water use, local communities and food prices are also considerable. Then, even ignoring the ILUC effects, the area needed to cultivate crops required to decarbonize the maritime sector would be enormous and would run counter to the efforts to increase negative emissions and carbon sinks, which will be required as part of the Paris Agreement. [38] [9]

Advanced biofuels, from waste or residues, could still play a positive role in decarbonising the maritime sector. While there is no question about sustainability, their availability is limited due to wastes and residues being incidental to other processes. Their availability for the shipping sector will be further reduced by the high demand for advanced biofuels from other transport sectors (like aviation) and non-transport industries, limiting their availability and increasing their cost. Because of the limited availability of feedstock and demand from other sectors, the supply of advanced biofuels will not be sufficient to reach decarbonisation targets.

9 IEA defines advanced biofuels as "sustainable fuels produced from non-food crop feedstocks, capable of delivering significant lifecycle GHG emissions reductions compared with fossil fuel alternatives, and which do not directly compete with food and feed crops for agricultural land or cause adverse sustainability impacts."

Moreover, the use of biofuels in shipping would create unique sustainability and enforcement challenges, which do not arise in other transport modes and would appear to be insurmountable from a regulatory point of view. Ocean-going ships usually bunker in specific ports where fuel is cheap; hence, they do not need to refuel every time they make a port call to take up or discharge cargo. Such a unique refuelling pattern of shipping makes the application of strict sustainability criteria for biofuels -to prevent the use of crop-based biofuels extremely challenging. [39]

A global and uniform application of sufficiently strict sustainability criteria - via, for example, the IMO or another framework - would require a global consensus agreement, which is improbable because of the interests of large bioenergy producing countries such as Brazil, Argentina, the US, Colombia, Indonesia, Malaysia, etc. Even if such a global consensus on applying strict environmental criteria were reached, uniform enforcement would be an additional and equally insurmountable challenge. [39]

Liquefied Natural Gas (LNG)

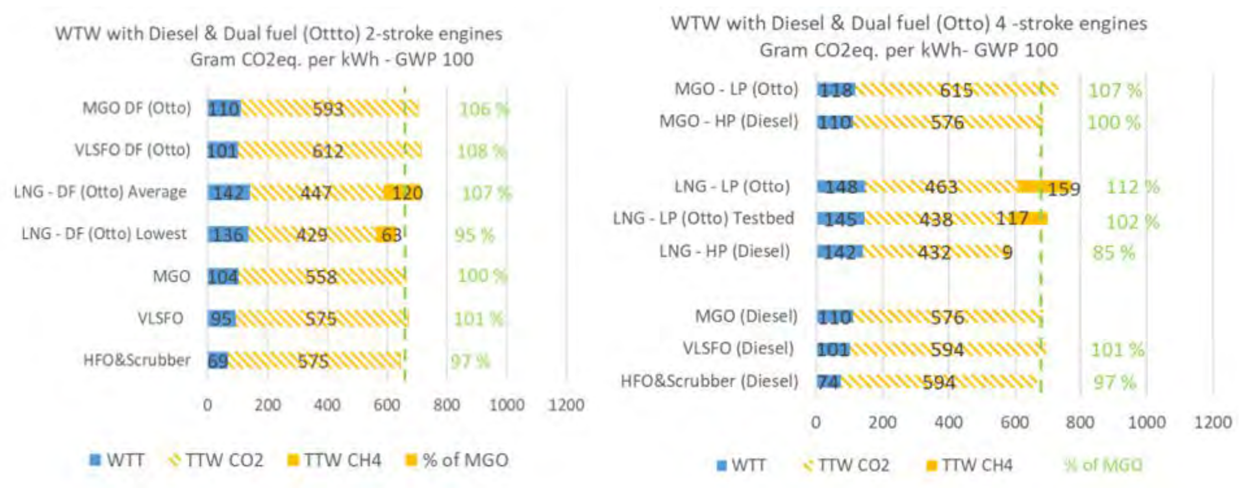
LNG became the most adopted alternative marine fuel as of 2020. Its initial adoption has been facilitated by increasing SOx and NOx emission standards as well as increasing world trade of LNG and proliferation of LNG liquefaction facilities and LNG terminals.

While LNG currently dominates the alternative fuel vessel infrastructure, its importance in a low carbon maritime shipping sector is uncertain. It is certainly true that LNG provides significant opportunities for reducing air pollution from shipping. Compared to heavy fuel oil (HFO) and marine diesel oil (MDO), LNG propulsion produces only trace amounts of SOx and particulate matters while NOx emissions can be reduced by 91.4% [40]. Unfortunately, in terms of CO2 emissions, the potential GHG savings are limited.

Taking into account LNG combustion only, total CO2 reductions from using LNG might reach around 25% compared to MGO or HFO [41]. However, relatively large Well-to-Tank (WTT) emissions of the LNG supply chain [42] as well as methane slip from the ship's engines, more or less offset any GHG savings from LNG combustion [43].

As a result, multiple studies ([43], [44], [45], [46]) have recently shown that the only LNG option which can realistically have a positive contribution towards GHG reduction is the 2–stroke high-pressure dual fuel option and even there the total GHG reductions are only around 15% compared to MGO.

Figure 21. Comparison of LNG WTW GHG emissions with other fossil fuel options



Source: [46].

Therefore, it is clear that, while LNG enables air pollution reduction, it is certainly not an option for decarbonisation of shipping.

4.5 Current status of hydrogen technologies in shipping

Lack of consensus on what will be the future fuel of choice is one of the key barriers preventing hydrogen to move from R&D phase into wider adoption

Fuel Cells (FC) and hydrogen have been already successfully implemented in submarines for many years. In the private sector, the use of hydrogen as a fuel has been demonstrated in small inland and near-coastal vessels, proving the viability of the technology. Besides, demonstration projects on small ferries are under construction. Larger vessels are generally at the design study stage, and a range of fuels and fuel cell types are currently being tested. The European hydrogen and fuel cell supply chain is scaling up, with formal cooperations and joint ventures between FC manufacturers and maritime power train providers.

Demonstration projects are underway to highlight the viability of hydrogen to power ships using FCs and modified combustion engines. For certain use types (inland, near coastal), there is an emerging consensus that FCs, using H2 is the most promising zero-emission (ZE) option. In addition, several design projects are ongoing to test the applicability of FCs to larger vessels. However, due to the magnitude of energy storage and power required in these use cases, no consensus on the optimal strategy for fuel.

The growing interest in hydrogen as a fuel for the maritime sector can be demonstrated by the progress achieved in projects funded by the Fuel Cell and Hydrogen Joint Undertaking (FCH JU).[10]

10 The Fuel Cells and Hydrogen Joint Undertaking (FCH JU) is a public-private partnership supporting research, technological development and demonstration activities in fuel cell and hydrogen energy technologies in Europe. Its aim is to accelerate the market introduction of these technologies, realising their potential as an instrument in achieving a carbon-clean energy system. The three members of the FCH JU are the European Commission, fuel cell and hydrogen industries represented by Hydrogen Europe and the research community represented by Hydrogen Europe Research.

The first projects started only in 2011 with the development of a small-scale fuel cell providing only auxiliary power for yachts. Then, progressively the projects grew both in size and ambition to reach Multi-MW Fuel Cell Ships using Ammonia (2019 project "ShipFC"[11]) or liquid hydrogen as a fuel.

Figure 22. R&D Projects in the maritime sector funded by the FCH JU

Source: Hydrogen Europe, based on https://www.fch.europa.eu/page/fch-ju-projects.

These are by far not all hydrogen projects in the maritime sector that were, or are being developed, with a number of other initiatives funded by other programmes than the FCH JU and national governments in and outside of Europe.

One of such projects is the Interreg North-West Europe Project H2SHIPS (where Hydrogen Europe is part of the consortium), which will demonstrate the technical and economic feasibility of hydrogen bunkering and propulsion for shipping and will identify the conditions for successful market entry for the technology. Two pilot projects will be implemented as part of H2SHIPS: A new hydrogen-powered port vessel will be built in Amsterdam and in Belgium, an H2 refuelling system suitable for open sea operation will be developed and tested.[12]

Yet, even though the interest in hydrogen is growing, there are still some key barriers that need to be overcome before hydrogen can become a mainstream solution for shipping. One of the most important of those barriers is of course a high price of clean hydrogen and sustainable e-fuels as well as a lack of bunkering infrastructure. The regulatory framework is also lagging, both in terms of technical regulation as well as policies. One of the reasons those barriers persist is a lack of consensus about what will be the future fuel of choice for the sector.

It is understandable that given the long lifetime of ships facing the risk of stranded assets, the shipowners are reluctant to invest in large vessels using alternative fuels. It is also understandable that facing the same uncertainty, maritime ports are unwilling to invest in alternative fuels storage and bunkering infrastructure.

The remaining part of this paper aims to reduce this uncertainty.

11 https://www.fch.europa.eu/page/transport#ShipFC
12 https://h2ships.org/ and https://www.nweurope.eu/projects/project-search/h2ships-system-based-solutions-for-h2-fuelled-water-transport-in-north-west-europe/#tab-1

5. Techno-economic analysis

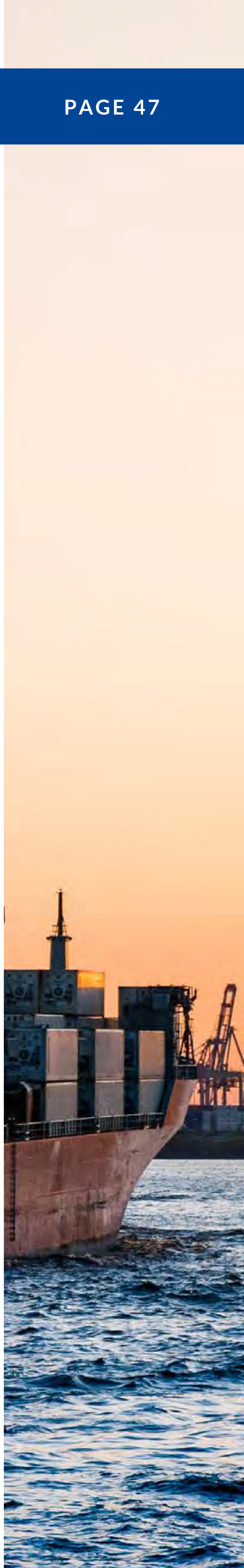
5.1 Scope of the analysis

The analysis is made based on the total cost of ownership comparison and covers all sea-going vessels - from ships used exclusively for short sea application e.g. ferries, ro-ro ships, general cargo ships and small containerships, through cruise ships up to ships used mostly on intercontinental voyages, e.g. VLCCs, VLBCs and large containerships

The economic comparison of different options has been evaluated using an approach similar to Levelized Cost of Electricity – in the sense that the final costs borne by the shipowners include actualized investment (CAPEX) and operating (OPEX) costs of different options and are put in relation to the amount of fuel consumed. To ensure comparability of options the fuel consumption has been expressed in kWh of the energy content of the fuel (based on LHV) instead of its mass (in kg or tonnes). The discount rate used to actualize investment costs has been fixed at 5% p.a. in real terms.

The model includes the following elements:

- Hydrogen production costs – Levelised costs of producing renewable hydrogen via water electrolysis.
- Transformation and conditioning costs – costs of transforming pure hydrogen into the final fuel. Includes compression or liquefaction for pure hydrogen options, hydrogenation for LOHC and N2/CO2 supply and synthesis for e-fuels.[13]
- Fuel logistics costs - costs of transporting the fuel from its production site to the storage facility in the port. Together with hydrogen production costs and transformation and conditioning costs, these three categories combined represent the total cost of fuel to be paid by the shipowner.[14]
- Storage costs – costs of fuel onboard storage system, including also impact of the extra volume of space needed on the revenue-generating potential of the ship.[15]
- Onboard reforming costs - costs of additional equipment (if needed) for treatment and cleaning of the fuel before it can be burned or used in a fuel cell.[16]
- Energy conversion costs – costs related to the final energy converter (marine engine or a fuel cell), converting the fuel into useful energy for propulsion or electric energy supply.[17]



13 Details about the assumed pathways for production of various fuels are presented in Annex 1 and detailed techno-economic assumptions are presented in Annex 2.
14 Detailed techno-economic assumptions are presented in Annex 3.
15 Detailed techno-economic assumptions are presented in Annex 4.
16 Detailed techno-economic assumptions are presented in Annex 5.
17 Detailed techno-economic assumptions are presented in Annex 6.

Figure 23. Techno-economic analysis model structure

Equal for all ship types			Depending on ship type (power requirements, range, operational profile, etc.)		
Fuel costs			**Storage**	**Reforming**	**Power**
Hydrogen production costs	Transformation and Conditioning	Transport costs + Shore-slide storage	Tank costs + Monetisation of lot payload capacity	Onboard reformer (if needed)	Main engine and/or auxiliary engine

Source: own elaboration.

As has been mentioned before, the maritime sector is very diverse and encompasses a wide variety of ship types, which differ not only by size and cargo but also have vastly different power requirements and operational profiles. As a result, it is rather unlikely that there will be a single one-size-fits-all solution to decarbonize the entire sector.

The techno-economic analysis was performed separately for 61 different ship-types to tackle this diversity, as defined in the recent IMO GHG Study [10]. For every ship type, we have assigned a minimum distance that ship type needs to be able to cover on a single tank. It should be noted that this is not based on the amount of fuel carried currently on average by various ship types but is an estimation of a minimum fuel autonomy the ship needs to have for it not to negatively affect its business model. The distances were estimated based on various other studies ([47], [48]) supported with own estimations.

The following table shows an overview of ship types included in the analysis. Detailed assumptions are presented in Annex 7.

Table 4. Ship types included in the analysis

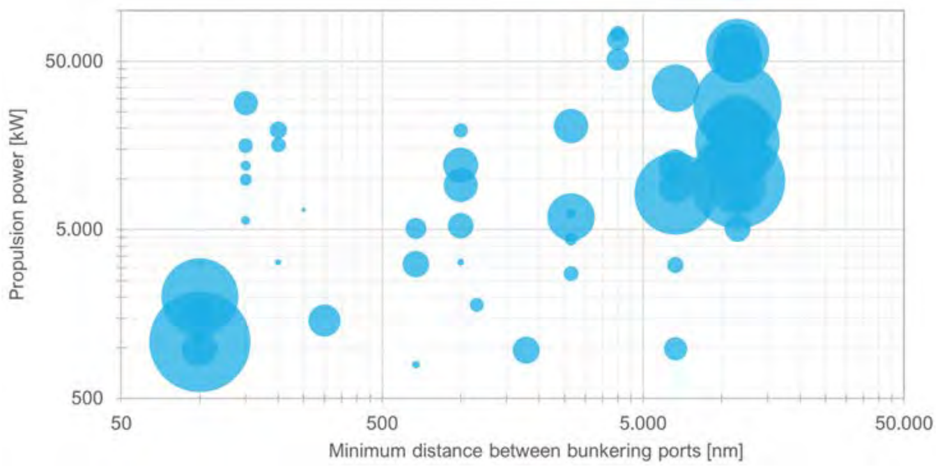
Ship type	Size	Size unit	Number of ships active	Avg. DWT (tonnes)	Avg. GT	Average main engine power (kW)	Minimum fuel autonomy (nm)
Bulk carrier	0–9,999	dwt	1,446	4.271	2.104	1,796	1,152
Bulk carrier	10,000–34,999	dwt	2,014	27.303	17.301	5,941	2,650
Bulk carrier	35,000–59999	dwt	3,391	49.487	30.582	8,177	6,650
Bulk carrier	60,000–99,999	dwt	3,409	76.147	41.538	9,748	11,500
Bulk carrier	100,000–199,999	dwt	1,242	169.868	88.277	16,741	11,500
Bulk carrier	200,000–+	dwt	516	251.667	130.223	20,094	11,500
Chemical tanker	0–4,999	dwt	6,067	4.080	1.392	987	6,650
Chemical tanker	5,000–9,999	dwt	862	7.276	4.854	3,109	6,650
Chemical tanker	10,000–19,999	dwt	1,088	15.324	9.751	5,101	11,500
Chemical tanker	20,000-39,999	dwt	706	32.492	23.223	8,107	11,500
Chemical tanker	40,000–+	dwt	1,289	48.796	36.808	8,929	11,500
Container	0–999	TEU	1,027	8.438	6.452	5,077	673
Container	1,000–1,999	TEU	1,271	19.051	15.019	12,083	1,000
Container	2,000–2,999	TEU	668	34.894	27.756	20,630	2,650
Container	3,000–4,999	TEU	815	52.372	42.867	34,559	6,650
Container	5,000–7,999	TEU	561	74.661	68.337	52,566	11,500
Container	8,000–11,999	TEU	623	110.782	100.228	57,901	11,500
Container	12,000–14,500	TEU	227	149.023	145.455	61,231	11,500
Container	14,500–19,999	TEU	101	179.871	177.304	60,202	11,500
Container	20,000+	TEU	44	195.615	217.850	60,210	11,500
General cargo	0–4,999	dwt	13,296	2.104	1.206	1,454	300
General cargo	5,000–9,999	dwt	2,245	6.985	4.894	3,150	673
General cargo	10,000–19,999	dwt	1,054	13.423	9.444	5,280	1,000
General cargo	19,999+	dwt	793	36.980	22.424	9,189	1,000
Oil tanker	0–4,999	dwt	9,692	3.158	1.181	966	1,784
Oil tanker	5,000–9,999	dwt	779	6.789	4.570	2,761	2,650
Oil tanker	10,000–19,999	dwt	235	14.733	9.985	4,417	2,650
Oil tanker	20,000–59,999	dwt	615	43.750	27.500	8,975	6,650
Oil tanker	60,000–79,999	dwt	429	72.826	41.863	11,837	6,650

Ship type	Size	Size unit	Number of ships active	Avg. DWT (tonnes)	Avg. GT	Average main engine power (kW)	Minimum fuel autonomy (nm)
Oil tanker	80,000–119,999	dwt	1,029	109.262	60.338	13,319	11,500
Oil tanker	120,000–199,999	dwt	597	155.878	82.393	17,446	11,500
Oil tanker	200,000–+	dwt	755	307.866	160.060	27,159	11,500
Ferry-pax only	0-299	GT	10,680	65	185	1,152	100
Ferry-pax only	300-999	GT	666	102	543	3,182	100
Ferry-pax only	1,000-1,999	GT	51	354	1.421	2,623	100
Ferry-pax only	2000-+	GT	55	1.730	6.443	6,539	100
Cruise	0–1,999	GT	812	241	906	911	100
Cruise	2,000–9,999	GT	110	867	5.008	3,232	200
Cruise	10,000–59,999	GT	105	4.018	31.105	19,378	1,000
Cruise	60,000–99,999	GT	98	8.249	79.947	51,518	4,000
Cruise	100,000–149,999	GT	61	10.935	123.801	67,456	4,000
Cruise	150,000+	GT	21	13.499	174.893	73,442	4,000
Ferry – ro-pax	0–1,999	GT	2,854	309	669	1,383	100
Ferry – ro-pax	2,000-4,999	GT	400	832	3.053	5,668	100
Ferry – ro-pax	5,000-9,999	GT	227	1.891	7.171	12,024	100
Ferry – ro-pax	10,000-19,999	GT	231	3.952	14.123	15,780	150
Ferry – ro-pax	20,000-+	GT	282	6.364	31.985	28,255	200
Refrigerated bulk	0–1,999	dwt	1,371	2.409	651	793	673
Refrigerated bulk	2,000-5,999	dwt	213	3.986	3.388	3,223	1,000
Refrigerated bulk	6,000-9,999	dwt	182	7.476	7.151	6,206	2,650
Refrigerated bulk	0,000-+	dwt	157	12.612	11.727	11,505	6,650
Ro-ro	0–4,999	dwt	2,174	1.406	3.847	1,618	100
Ro-ro	5,000-9,999	dwt	202	6.955	11.524	9,909	150
Ro-ro	10,000-14,999	dwt	135	12.101	25.131	15,939	150
Ro-ro	15,000-+	dwt	89	27.488	51.780	19,505	200
Vehicle	0-29,999	GT	168	5.151	20.693	7,264	11,500
Vehicle	30,000-49,999	GT	189	13.571	32.433	11,831	11,500
Vehicle	50,000-+	GT	487	20.947	46.667	14,588	11,500
Service – tug	0–+	GT	76,266	1,218	2,067	1,086	100
Fishing	0–+	GT	36,530	468	530	983	100
Offshore	0–+	GT	16,893	4,765	5,391	2,010	100
Service	0–+	GT	12,419	2,496	1,187	1,620	100

Source: [10]

Looking at the gross tonnage of various sip types, one can notice that deep-sea shipping applications, where ships cannot bunker more often than 6.000 – 12.000 nautical miles, comprise most of the market, with another sizeable part made up by the Ro-Ro and Ro-Pax ferries used mostly on short routes.

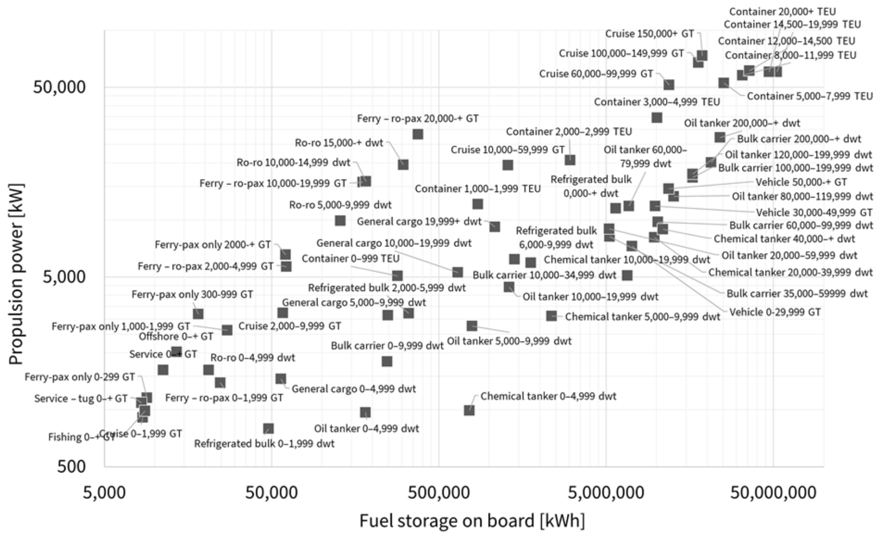
Figure 24. The spread of analysed ship typed by propulsion power, the distance between bunkering and total gross tonnage (size of the bubble)



Source: own elaboration.

Based on the installed main engine power, average power utilization, average speed (all based on [10]) combined with the assumed minimum distance between bunkering, it is also possible to estimate the minimum amount of fuel each ship type needs to carry onboard (see figure below).

Figure 25. The spread of analysed ship typed by propulsion power, the distance between bunkering



Source: own elaboration.

The analysed sample allows for covering the entire sector of sea going vessels, with a wide range of power and onboard energy storage requirements - from ships used exclusively for short sea application e.g., ferries, ro-ro ships, general cargo ships and small containerships, through cruise ships and up to ships used mostly on intercontinental voyages, e.g., VLCCs, VLBCs and large containerships.

5.2 Powertrain options

Besides compressed and liquefied hydrogen, this analysis also covers several hydrogen derivative options, like liquid organic hydrogen carriers and e-fuels (ammonia, LNG, methanol, diesel) made from hydrogen.

Although there are many hydrogen production pathways, for this analysis, we have considered only hydrogen produced from renewable energy via water electrolysis.

The use of point captured CO_2 for the production of e-fuels is recognized only as a transitional solution at best. For this reason, we have assumed that all CO_2 used for e-fuels synthesis would come from Direct Air Capture (DAC).

This analysis is not an assessment of the best available solutions today but rather a projection of the long-term viability of different hydrogen-based shipping decarbonisation options.

The purpose of the following analysis was to inform the Strategic Research and Innovation Agenda of the Clean Hydrogen for Europe partnership, technologies that are out of the scope of the partnership have been omitted. This does not, however, mean that the analysis covers only pure hydrogen as a fuel option. While using hydrogen directly is the most energy-efficient option, it is also possible to use it as an ingredient to produce synthetic e-fuels, which are particularly attractive for deep-sea shipping applications, where the energy density of the fuel is key for its financial viability. The synthetic e-fuels, produced from hydrogen, included in this paper are ammonia, LNG, methanol and diesel.

It's obvious that using hydrogen as its predominantly produced today, i.e., via steam methane reforming (SMR), would not bring any decarbonization benefits, and its manufacturing from fossil fuels needs to be replaced by renewable or low-carbon alternatives. Consequently, we have assumed that hydrogen used for all analysed options will be exclusive of renewable origin for this analysis.

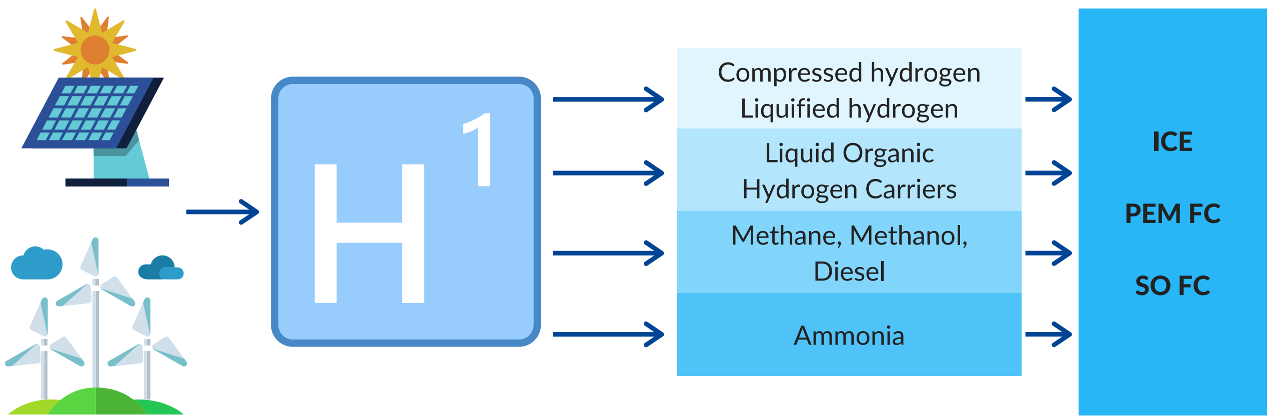
This does not mean that other low-carbon hydrogen production pathways are not suitable for decarbonization of shipping, but as this analysis is based on a techno-economic comparison, there is little added value in expanding the analysis to other hydrogen production methods, as they mostly impact hydrogen production costs and those have been analysed in detail as part of the sensitivity analysis.

When it comes to energy use onboard, it is also important to stress that it is possible to partially decarbonise shipping also by using hydrogen only as fuel for generating auxiliary power or co-combustion of hydrogen together with fossil marine fuel.[18]While those options present genuine opportunities for shipping, they are out of the scope of this analysis, which focuses only on options allowing for total decarbonisation of shipping.

Another important disclaimer that needs to be stressed concerns the technology readiness level (TRL) of various technologies. Because of its purpose, the analysis is forward-looking; for various technologies, we have assumed the technology readiness level will be market-ready as of 2030 and not how it is currently. This has the most profound impact on technologies like solid oxide fuel cells, which are still relatively immature and require significant further development to be a viable solution for large ships requiring multi-MW powertrains.

Because of this assumption, the results of this paper should not be seen as an assessment of the best available solutions today but rather a projection of the long term viability of different hydrogen-based shipping decarbonisation options.

Figure 26. Analysed fuel options



Source: own elaboration

18 E.g. https://www.internationales-verkehrswesen.de/hydroville-vessel-cmb/

5.2.1 Compressed and liquified hydrogen

The two "pure hydrogen" options covered in this analysis include compressed hydrogen (350 bar) and liquefied hydrogen. The advantage of those options lies with the less complicated fuel production process, as in both of those cases, to arrive at the final fuel, only one additional step is needed (compression or liquefaction, respectively). Usually, this translates into lower costs of production compared to the alternatives (see point 5.2).

On the other hand, the energy density of those two options is lower than the case for e-fuels (see point 5.3). As a result, the "pure" hydrogen options make the most sense for short sea shipping application, where the amount of fuel that needs to be stored onboard is lowest and therefore also the amount of lost payload capacity of ships, resulting from extra volume needed for fuel, is also relatively low. However, for deep-sea shipping, the implications of lower energy densities vs synthetic fuels are far more significant.

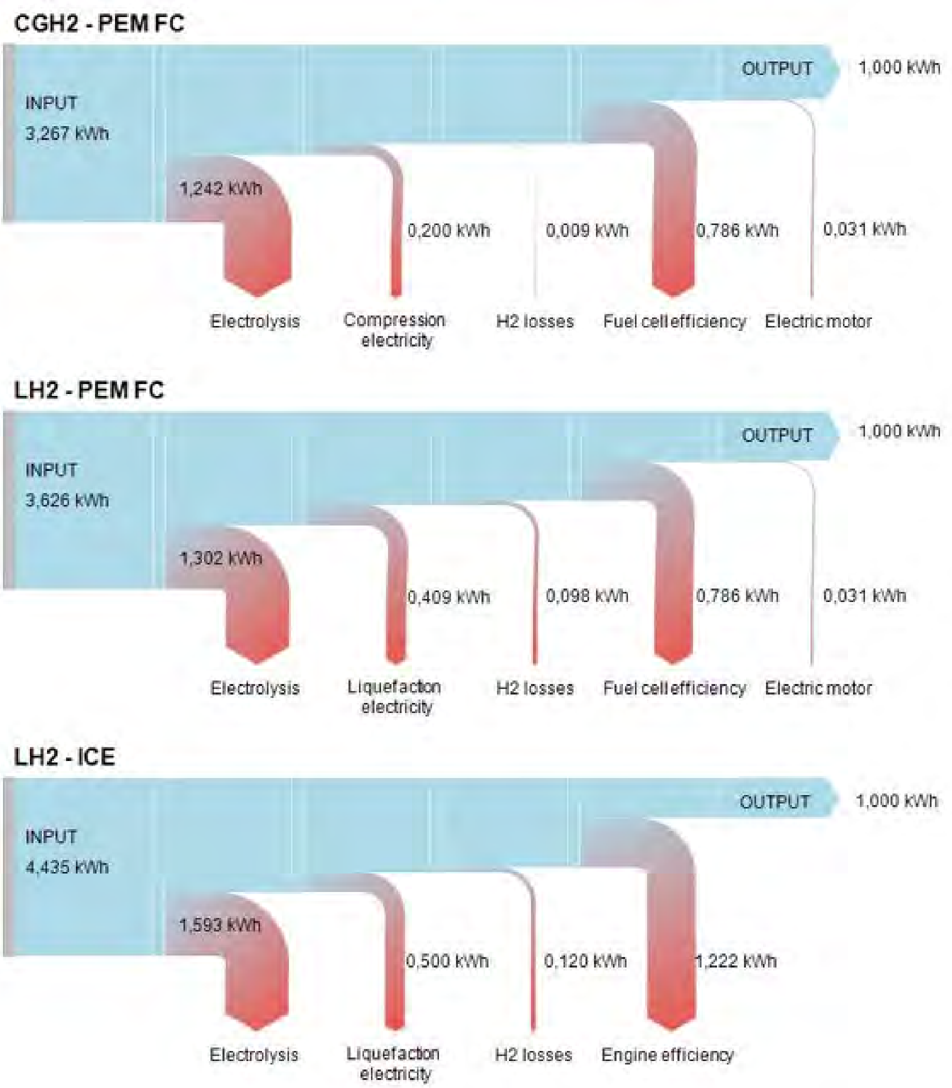
Another advantage of pure hydrogen options is the fact that neither requires any onboard reforming or cleaning before being used as fuel in a fuel cell or an internal combustion engine (ICE).

It should also be mentioned that it is also possible to use compressed hydrogen at different pressures – for example, 700 bar, as is the standard for passenger FCEV's, yet because of substantially higher costs than 350 bar, without high enough difference in energy density, this option was not included at this stage.

Another possible method cryo-compressed hydrogen storage, which is a mixture of compressed and liquid storage. The pressurized hydrogen is stored at temperatures above the boiling temperature at elevated pressure. It reaches its highest density at temperatures below -200 °C at pressures up to 1000 bar [47]. Since it is currently only in the prototype stage, it has not been included in the paper but will be considered in future updates of the analysis.

It is possible to use hydrogen in both fuel cells as well as combust it in an engine. From the energy efficiency point of view, PEM FC is the best option; they are also more mature and thus cheaper than the SOFC. SOFC's might still be a good option if the vessel has substantial heat requirements, e.g., for cruise ships. One of the advantages of fuel cells over combustion engines is the fact that the energy efficiency of fuel cells increases in partial load and can reach 60+%. Furthermore, the combustion of hydrogen in the air might result in the formation of NOx, which does not occur in fuel cells.

Figure 27. The energy efficiency of pure hydrogen options



Source: own elaboration.

5.2.2 Hydrogen carriers

Hydrogen is one of the most energy-dense fuels by mass but it is extremely light and so the volumetric energy density in standard conditions is very low. Conventional hydrogen delivery solutions solve this problem by either compressing and delivering a pressurised gas, or by liquefaction and delivery of a liquid. Alternative solutions include using hydrogen carriers.

Hydrogen carriers store hydrogen by hydrogenating a chemical compound at the site of production or onboard and then possibly dehydrogenating either at the point of delivery or potentially onboard the fuel cell vehicle for transport applications. They are largely at the research stage and have yet to be proven to be cost, energy/roundtrip efficient. They may include for example liquid organic hydrogen carriers (LOHCs) or inorganic hydrogen carriers (e.g. borohydrides, polysilane).

LOHCs are typically hydrogen-rich aromatic and alicyclic molecules, with high hydrogen absorption capacities. They include, in particular, carbazole derivative N-ethyl carbazole, but also toluene, which is converted to methylcyclohexane by hydrogenation, dibenzyl toluene, and others [25].

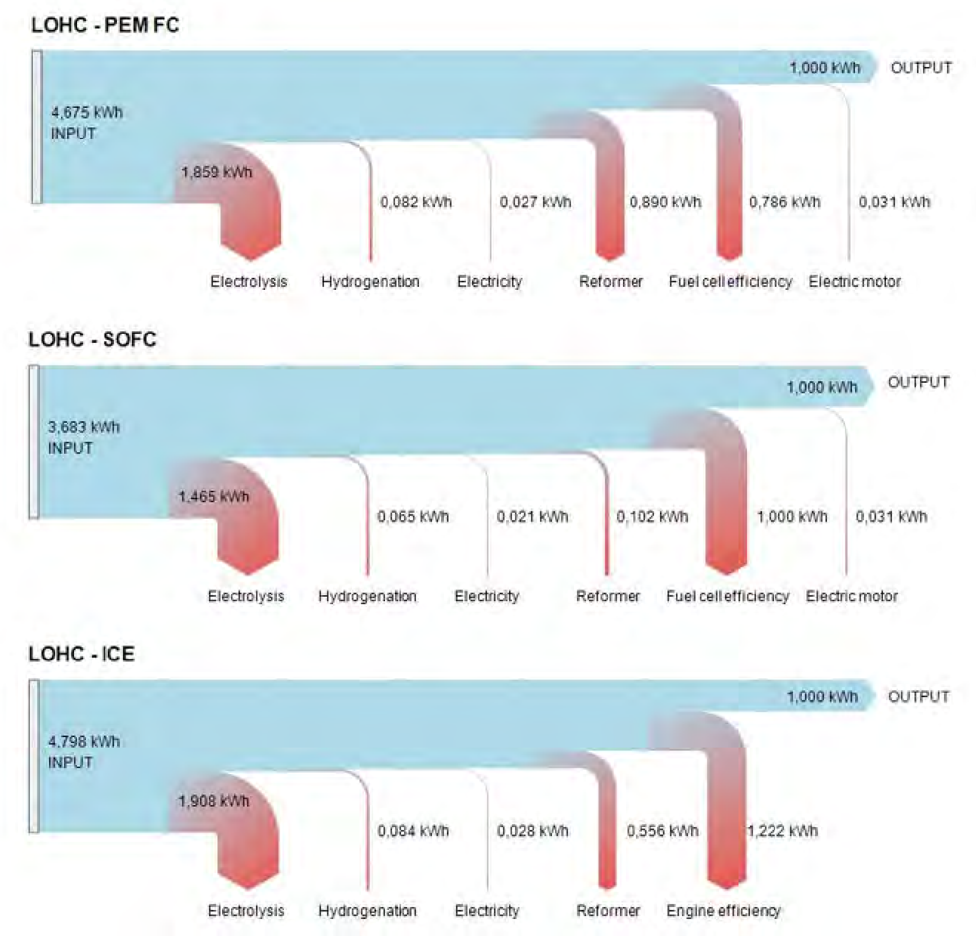
The hydrogenation reaction occurs at elevated hydrogen pressures of 10-50 bar and is exothermic, releasing about 9 kWh/kg H2, which can be used locally for heating or process purposes or must be otherwise dissipated.

Dehydrogenation is endothermic and occurs at low pressures between 1 and 3 bar. The unloaded carrier is returned to the production site for reloading with possible degradation of the carrier happening depending on chemistries, operating conditions, and the number of cycles. Dehydrogenation plays a key role in deciding the suitability of using LOHC as a fuel carrier for shipping applications. The necessity to extract hydrogen from LOHC before it can be used as a fuel requires additional equipment (dehydrogenation unit) to be carried on board, which diminished somewhat the energy density properties of the fuel itself. In addition to dehydrogenation, for use in PEM Fuel Cells (PEMFC), hydrogen extracted from LOHC would require additional purification step – although, when used with high-temperature solid oxide fuel cells (SOFC) or in an ICE, purification is not needed.

A further complication is related to the endothermic characteristic of the dehydrogenation process itself. If one would recover heat from the dehydrogenated liquid with an additional gas heater, about one-third of the energy stored in LOHC would be required to sustain the dehydrogenation reaction - further increasing the amount of fuel that would need to be stored onboard. This is less of a problem if LOHC would be used in combination with an ICE or SOFC, which could provide enough waste heat to maintain the dehydrogenation process.
In terms of volumetric energy density, one litre of LOHC contains around 1,32 kWh of hydrogen, which is higher than compressed hydrogen (0,81 kWh/l at 350 bar) but lower than liquefied hydrogen (2,359 kWh/l).

Its advantages come mostly from the ease of transport and storage. The hydrogenated carbazole derivative has comparable physicochemical properties to diesel fuel and can be stored and transported accordingly [25]. No pressurization or low temperature is needed. There are also no losses during storage. LOHC (both hydrogenated and dehydrogenated) is also non-toxic and inflammable. It can also be stored at ambient conditions in standard steel tanks used today to store other marine fuels. This opens the potential for LOHC to use existing bunkering infrastructure in ports.

Figure 28. The energy efficiency of LOHC options



Source: own elaboration.

Another group of hydrogen carriers, which are getting increased attention for maritime applications are metal hydrides. In metal hydride storage systems, hydrogen forms interstitial compounds with metals. Generally, similarly to LOHC, the "loading" of hydrogen onto the metal hydride is an exothermic process (releasing heat), while heat needs to be supplied to keep the dehydrogenation process going. Metal hydrides are based on elemental metals such as palladium, magnesium and lanthanum, intermetallic compounds, light metals such as aluminium, or certain alloys. Although this may differ depending on the specific metal hydride solution chosen. Palladium, for example, can absorb a hydrogen gas volume up to 900 times its volume [25] [47].

Two of the most promising solutions are based on using sodium borohydride ($NaBH_4$) or Mg-Al alloys as hydrogen carriers. Using metal hydrides for hydrogen storage can achieve volumetric density matching that of liquefied hydrogen.

The challenges are related to the low gravimetric energy density (hydrogen is only accounting for around 1-2% of the mass of the carrier) and the fact that the regeneration of the carrier after the dehydrogenation reaction is often extremely complex and costly.[19]

19 For more information on metal hydrides, their prospects and ongoing research see e.g. [84].

Advantages include the filter effect of metallic storage, allowing high-purity hydrogen to be discharged, and the low potential of accidental release [25].

Even though metal hydrides are potentially a very promising solution, as metal hydride storages are not yet available as a commercial product, they have been omitted from this analysis at this stage but will be included in future updates.

5.2.3 Ammonia

NH3 is a colourless inorganic compound that can be used in fuel cells or as a fuel for direct combustion in an ICE. It has a high hydrogen content but does not contain any carbon or sulphur molecules. As a result, the combustion of ammonia does not emit any carbon dioxide (CO2) or sulphur oxide (SOx). It is s a technically feasible solution for decarbonizing international shipping.

It has been estimated that depending on the used propulsion type and specific ammonia production method, ammonia fuelled ships could reduce GHG emissions by approximately 83.7–92.1% [48].

The exact emissions of NOx, as well as the global warming potential of ammonia slip and N2O emissions from ammonia combustion, require further research. Especially N2O requires significant attention as it is a GHG with almost 300 x higher global warming potential than CO2.

Ammonia is an interesting case among the synthetic e-fuels options not only because it is the only fuel that does not contain a carbon molecule but also because it is already produced globally in large volumes, which makes a fast transition towards decarbonization easier than with some alternatives.

Given ammonia's use as a fertilizer, it is a widely traded commodity with a volume of international trade of up to 20 million tonnes, with 17 Mt of that being sea trade. As a result, there are operating transportation and storage infrastructures as well as port infrastructure for shore-to-ship loading/unloading, handling experience, and safety know-how in the current supply chain.

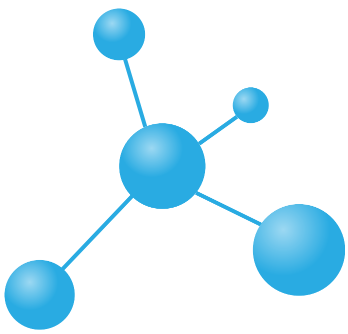
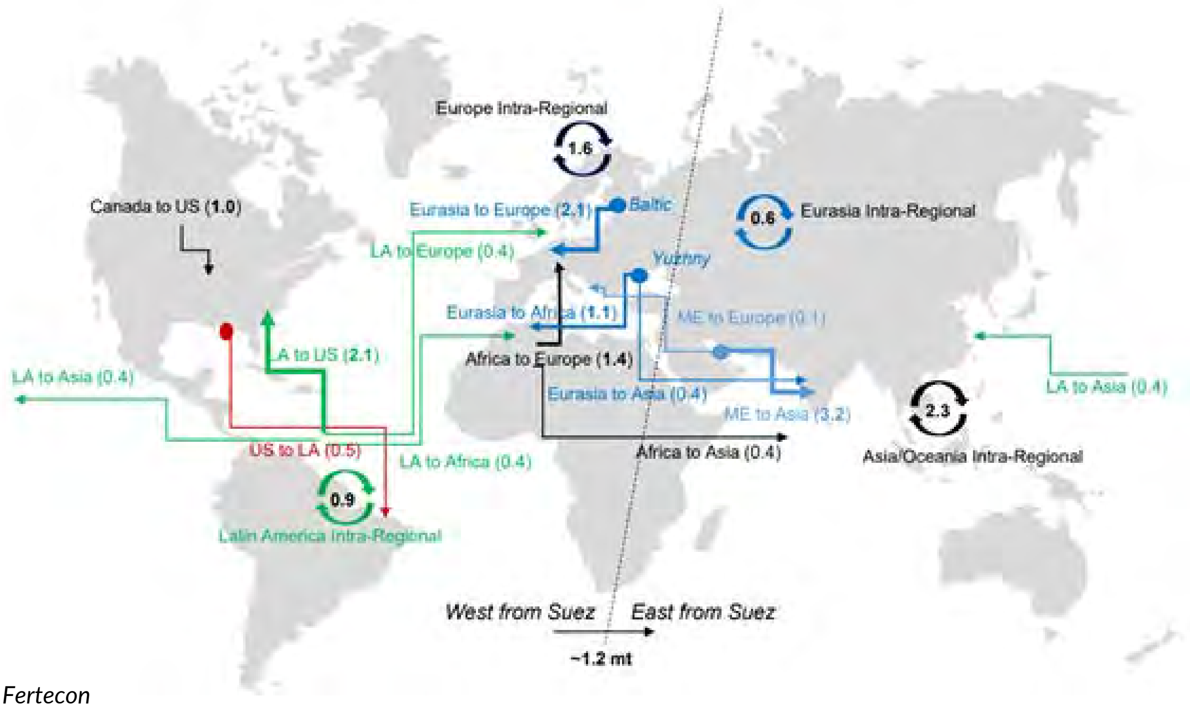


Figure 29. International trade flows of ammonia



Source: Fertecon

The Norwegian ammonia producer – Yara alone has 4 ammonia export plants in Europe with an export capacity of around 1 Mt and 2.7 Mt worldwide, together with an ammonia maritime transport capacity of more than 200 kt and 17 terminals with a storage capacity of 580 kt. Furthermore, as ammonia can be stored under similar conditions as LPG, it can also utilize the existing LPG fleet and LPG storage facilities.

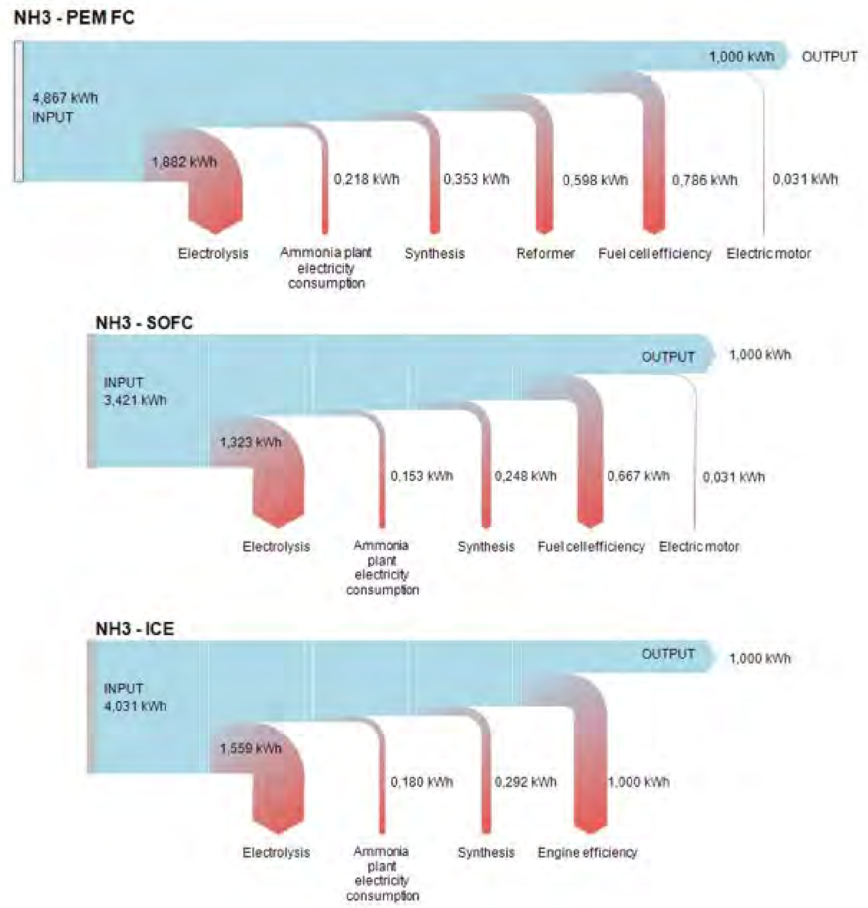
Very much like hydrogen, the deployment of ammonia as a marine fuel is still in the research and development phase. It is currently being tested for use in ships by various companies, including Wartsila and a consortium of Samsung Heavy Industries, MISC, Lloyd's Register (LR) and MAN Energy Solutions. [20], [49], [50].

Liquid ammonia's volumetric hydrogen content, at 14,500 MJ/kg, is 70% greater than liquid hydrogen's at 8500 MJ/kg. Liquid ammonia thus allows more energy storage per cubic meter than in liquid hydrogen and without the need for cryogenic temperature storage, as is the case of liquid hydrogen. This represents cost savings as storing ammonia at -33.4 C is technologically easier and cheaper than storing hydrogen at -252.9 C. [51]

Ammonias advantage also lies with the fact that its synthesis (via the Haber-Bosch process) is relatively energy efficient (around 14% energy loss), and contrary to hydrogen carriers, it can be used directly in a high-temperature fuel cell or burned in an ICE without the need for costly dehydrogenation step onboard (although this would not be possible for a low-temperature PEM fuel cell, which would require ammonia cracking and hydrogen purification).[20]

20 More information on ammonia as a fuel available at: [85], [86].

Figure 30. The energy efficiency of ammonia options



Source: own elaboration

In terms of risk of fire or explosion, it is safer than hydrogen or hydrocarbons, as it requires both higher ignition temperature and higher concentration in the air before the Air-NH3 mixture becomes flammable. The main disadvantage of ammonia is related to its toxicity, which makes its use on passenger ships especially challenging.

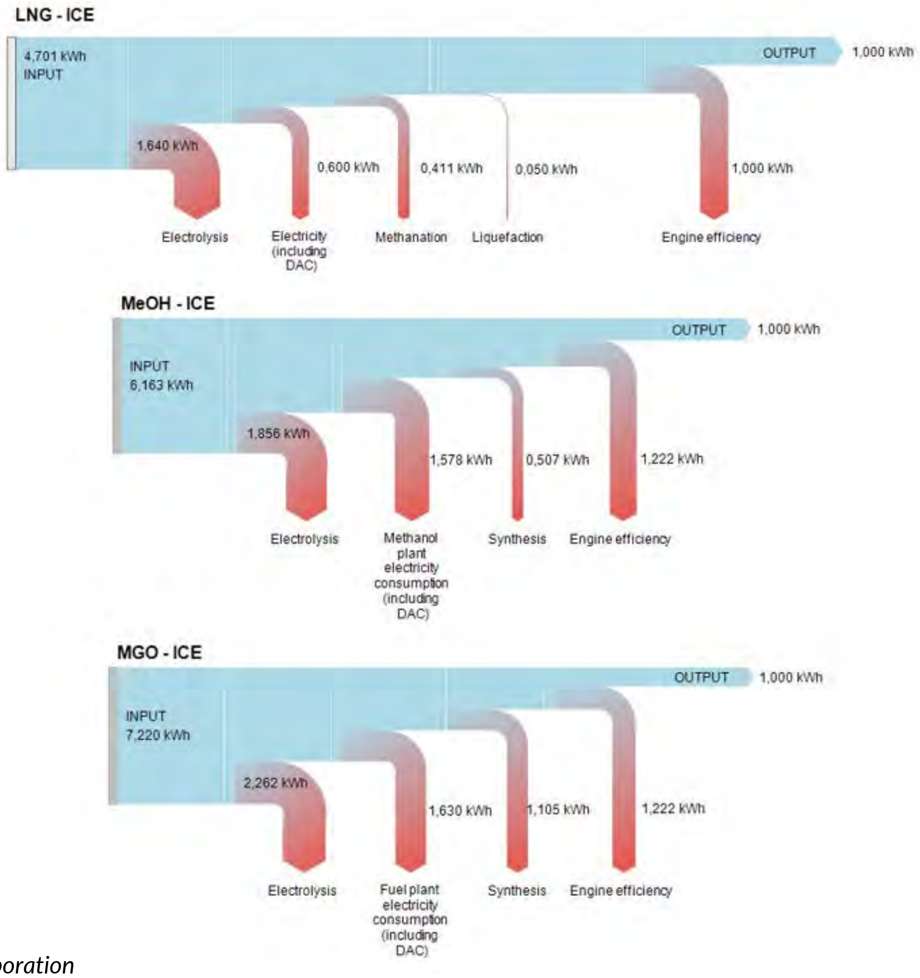
Although at the same time, the fertilizer industry has been working with ammonia for many decades and has developed standards and guidelines that can be followed to ensure safe usage of this chemical. Ammonia's strong smell makes it also easy to detect well before it reaches dangerous concentration levels.

It should also be mentioned that there already exists an IGC Code with requirements for carrying anhydrous ammonia in bulk, which can be used to guide non-gas carriers (IGF Code).

5.2.4 Other e-fuels

Synthetic e-fuels like methane, methanol or other hydrocarbons have higher energy density and are generally simpler to handle than ammonia or liquefied hydrogen. They also benefit from the fact that there is already storage and transportation infrastructure in place. This is, of course, most valid for synthetic diesel, but it is also the case for both LNG as well as methanol, which is already available at around 100 ports around the globe.

Figure 31. The energy efficiency of various e-fuel options



Source: own elaboration

Furthermore, the production of such carbon-based e-fuels will require a source of CO2, which will not only drive costs further up but has implications for the overall sustainability of those fuels.

By far, the cheapest source of CO2 would be to use the CO2 point captured from industrial processes or power plants, yet the long-term sustainability of this pathway is questionable. The CO2 saving credit can go either to the industry which has captured it or to the end-user (in this case, a ship); it can never go to both.

If it stays with the industry, then, from the point of view of GHG emissions, such synthetic fuel would be no better than its fossil fuel equivalent. If, however, the CO2 credit is attached to the e-fuel, then, while the fuel itself is climate neutral, the long term availability of CO2 is uncertain. If the ultimate goal of the EU is to become a fully decarbonized economy, the industry would have to decarbonize as well, meaning that, at some point, either the captured CO2 would have to be destined for permanent storage or the industry will transition to another zero-emission solution - either way, limiting the availability of CO2 for CCU. Furthermore, the use of CCU from fossil sources might potentially lead to the lock-in of fossil sources of CO2.

The use of point captured CO2 for the production of e-fuels can therefore be seen only as a transitional solution at best. For this reason, for this analysis, we have assumed that all CO2 used for e-fuels synthesis would come from Direct Air Capture (DAC).

5.3 Fuel production costs

Renewable hydrogen production costs for all options were estimated at 2.4 EUR/kg.

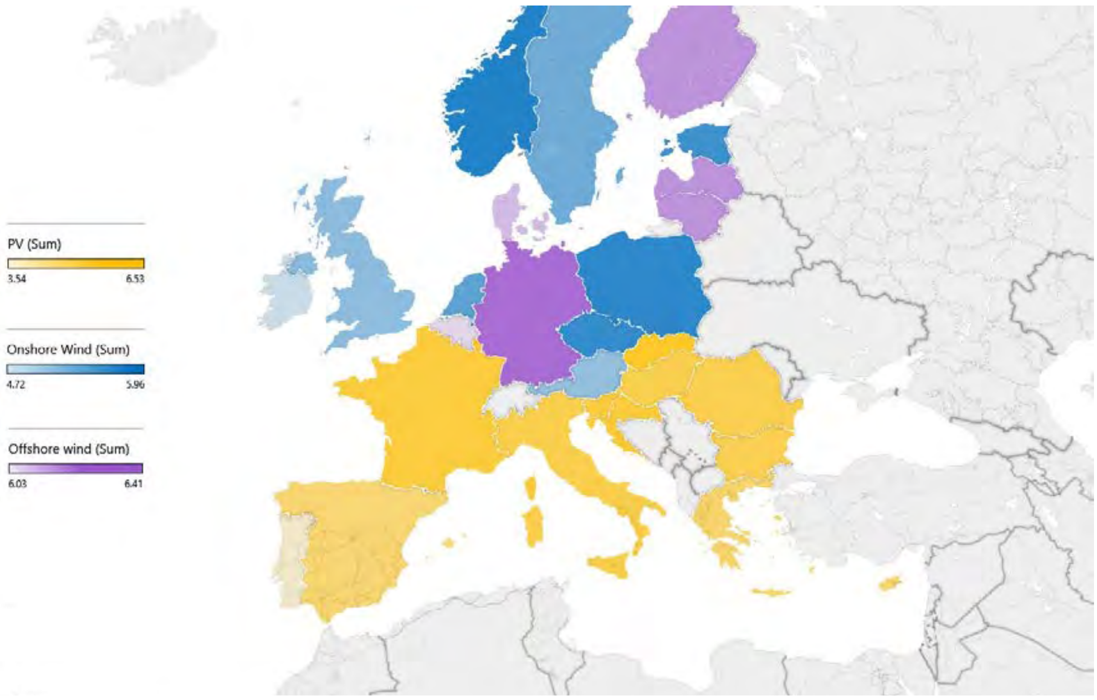
Even with such relatively low hydrogen production costs, all analysed alternative fuels would be significantly more expensive than the fossil fuel reference.

Hydrogen options, as well as LOHC, are substantially cheaper than all e-fuels - with green ammonia the cheapest among e-fuels.

Fuel production costs consist of combined costs of renewable hydrogen production and its transformation and conditioning required for it to reach its final form, which can be used as an energy carrier onboard ships.

Taking into account average solar irradiation and average wind conditions in the EU Member States, as well as Norway and the UK, estimated renewable hydrogen production costs with direct connection vary from €3.5/kg (from solar PV in Portugal) to €6.5/kg (from onshore wind in Luxemburg). In southern European countries, the cheapest pathway to green hydrogen production is solar PV, while for northern European countries, in most cases, the cheapest option is onshore wind, except for Belgium and Germany, where on average offshore wind is the cheapest option [24].

Figure 32. Lowest available green hydrogen production costs given average wind and solar conditions in the EU in 2019 (in € per kg)

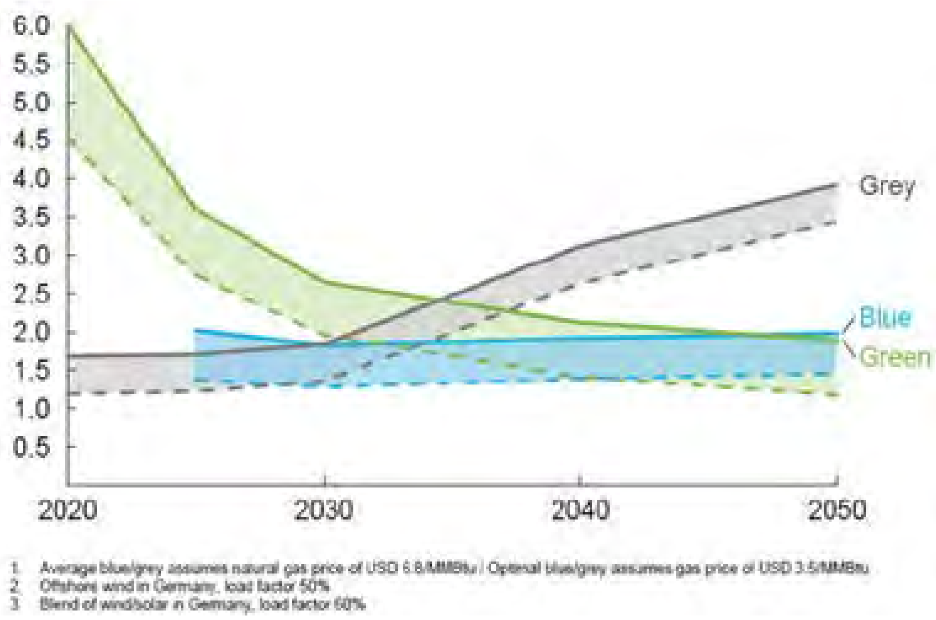


Source: [24].

Since this analysis is forward-oriented, we have decided to estimate the costs of hydrogen production also based on expected future electrolysis CAPEX as well as based on future renewable energy LCOE (40 EUR/MWh). Detailed techno-economic assumptions adopted to estimate different cost elements have been presented in detail in Annex 2. Based on those assumptions, renewable hydrogen production costs for all options were estimated at **2.4 EUR/kg.**

Such a price level, while below current production costs, is well within the range projected by McKinsey (see below) or the IEA (see [33]), IRENA and BNEF who project that by 2030, renewable hydrogen production costs will fall to **1.1-2.4 EUR/kg**. Such renewable hydrogen production costs are also in line with the EU Hydrogen Strategy goal of green hydrogen becoming cost-competitive with other forms of hydrogen production, including hydrogen from fossil fuels, which currently costs around 1.5 EUR/kg.

Figure 33. Production of hydrogen across different types of locations (in USD/kg)



Source: McKinsey.

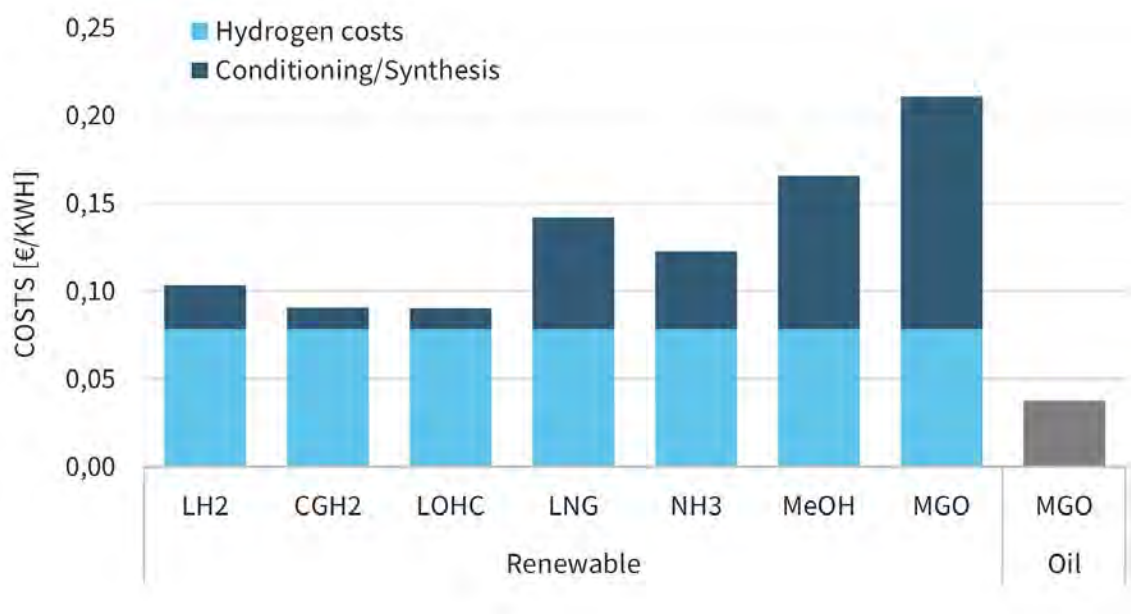
Even with such relatively low hydrogen production costs, assuming a marine gas oil (MGO) price of 500 USD/t, all analysed alternative fuels would be significantly more expensive than the fossil fuel reference.

The two most low-cost options in terms of fuel production costs would be compressed hydrogen (CGH2) and LOHC, with total estimated production costs at around 91 EUR/MWh, which more than twice that of MGO at around 38 EUR/MWh. Liquefied hydrogen is as expected a more expensive option compared to compressed hydrogen and LOHC with total estimated costs at 104 EUR/MWh (around 15% more than compressed hydrogen).

Yet, even so, both hydrogen options as well as LOHC, are substantially cheaper than all e-fuels, which is also not surprising considering the additional synthesis processes required to produce these fuels. The most expensive out of all the e-fuels is the synthetic MGO, which, at 211 EUR/MWh is 5.6 times more expensive than its fossil base equivalent.

Because of the lack of carbon molecules, green ammonia is significantly less expensive to produce than all other synthetic fuels. With production costs estimated at 123 EUR/MWh, it is 14% less expensive than its closer carbon-based e-fuel (e-LNG) and around 18% more expensive than liquefied hydrogen.

Figure 34. Estimated fuels production costs



Source: own elaboration.

5.4 Logistics costs

Compressed hydrogen is by far the most expensive option from the point of view of both transport and storage costs, which are around 42x higher than for MGO and 6x higher than for LNG. Liquid hydrogen logistics costs are around 15x higher than for MGO and twice as high as for LNG.

For bigger ports, it would be more economical to transport hydrogen to ports via pipeline and liquefy it on-site than to transport it in liquid form.

Logistics of alternative fuels pose a significant challenge, which would need to be overcome before any of the analysed options becomes universally adopted. For options like the LOHC or synthetic diesel, the challenges are less profound, as both of those options can use existing marine fuel transport, storage and bunkering infrastructures.

For synthetic LNG, ammonia and methanol, the challenges are greater but still, all of these options benefit from the fact that, as those are internationally traded commodities, there already is some infrastructure in place, which can be built upon. Due to similar storage requirements, ammonia could also use existing LPG storage facilities and transport ships.

By far, the biggest challenge of fuel logistics is faced by the pure hydrogen options. H2 presents unique challenges for transportation and distribution due to its low volumetric density. Furthermore, neither compressed nor liquefied hydrogen can benefit from any existing dedicated infrastructure of the same scale as some of the other options. On the other hand, in both of those cases, it is possible to reduce the time and cost necessary to put the transportation and storage infrastructure in place by retrofitting existing natural gas and LNG assets.[21]

Currently, the most commonly used hydrogen transportation methods include:

- **Road transport of gaseous hydrogen.** Most tube trailers in operation today deliver small quantities of compressed H2 gas at relatively low pressure (<200bar). At 200 bar, the density of hydrogen, under standard conditions, is around 15.6 kg hydrogen per cubic meter, meaning that a single tube trailer can carry only around 300 – 400 kg of hydrogen. The latest state of the art solution for road transport is 500 bar tube trailers. Under such pressure, hydrogen density would reach around 33 kgH2/m3, allowing to increase the capacity of a single truck up to 1,100kg H2. The ambition is to develop 700 bar tube trailers (c. 1,500kg) in the coming years.[22]

  Because of low amounts of hydrogen carried per truck, this option is relatively expensive for high quantities of hydrogen and long transport distances. However, compared to liquefaction or a pipeline network, there are virtually no fixed costs, so this is the best option for small amounts and short distances. It is also flexible since it is available for any route and at any time and is easily scalable. [25] [52]

- **Road transport of liquid hydrogen** – H2 in liquid form is the most conventional means of transporting bulk hydrogen on the road. The H2 is stored at -253°C in super-insulated 'cryogenic' tanks and can be safely transported by trucks over 4,000 km. However, liquefaction is energy-intensive, and storage/transport of the LH2 results in heat ingress and losses due to evaporation. "Boil-off" losses can be reduced by improved insulation concepts or, as demonstrated by NASA, by an integrated refrigeration and storage system. It should be noted that most of the boil-off happens during the transfer phase (Storage to Trailer, Trailer to local storage), far above the vaporisation inside storage tanks.

  Over the journey time, the cryogenic hydrogen heats up, causing the pressure in the container to rise. The evaporated hydrogen is extracted from the container, normally at the filling station, and supplied for another use or re-liquefied. Similar to lorry transport, LH2 can also be transported by ship or by rail, provided that suitable waterways, railway lines and loading terminals are available.

21 For more information on retrofitting natural gas infrastructure to hydrogen see the recent European Hydrogen Backbone report: [52].
22 See: Multiannual Work Programme of the Fuel Cell and Hydrogen Joint Undertaking (https://www.fch.europa.eu/) and the Strategic Research and Innovation Agenda of the proposed Clean Hydrogen for Europe partnership (available at https://hydrogeneurope.eu/clean-hydrogen-europe.eu).

In comparison to pressure gas vessels, more hydrogen can be carried with an LH2 trailer, as the density of liquid hydrogen is higher than that of gaseous hydrogen. At a density of 70.8 kg/m3, around 3,500 kg of liquid hydrogen or almost 40,000 Nm3 can be carried at a loading volume of 50 m3. Over longer distances, it is usually more cost-effective than transporting hydrogen in compressed gaseous form. The additional cost for hydrogen liquefaction is then offset by the lower trucking cost.

- **Pipelines** – for delivering large volumes of hydrogen over land, pipelines are by far the cheapest option. A pipeline network would be the best option for the comprehensive and largescale use of hydrogen as an energy source. However, pipelines require high levels of initial investment which may pay off but only with correspondingly large volumes of hydrogen. Nevertheless, one possibility for developing pipeline networks for hydrogen distribution is local or regional networks, known as micro-networks. These could subsequently be combined into transregional networks.

  Worldwide, there are already more than 4,500 km of hydrogen pipelines in total, the vast majority of which are operated by hydrogen producers. The longest pipelines are operated in the USA, in the states of Louisiana and Texas, followed by Belgium and Germany. In Europe, there is already >1000 km dedicated hydrogen pipelines serving the industry. This network should be expanded by newly build pure H2 pipelines.

  For the transport of very large hydrogen volumes, a comprehensive pipeline network is ideal. This option is dominated by the costs of building the pipeline infrastructure. Once it has been built, the increase in specific transport costs for larger volumes is negligible. A pipeline is thus the most cost-effective choice for large transport volumes, whereas for small amounts the fixed costs are very difficult to recover [25], [52], [53].

There also exists an option of blending hydrogen with natural gas. Blending hydrogen into natural gas pipeline networks has also been proposed as a means of delivering pure hydrogen to markets using separation and purification technologies downstream to extract hydrogen from the natural gas blend close to the point of end-use. As a hydrogen delivery method, blending can defray the cost of building dedicated hydrogen pipelines or other costly delivery infrastructure during the early market development phase. Until well into the 20th century, hydrogen-rich town gas or coke-oven gas with a hydrogen content above 50 vol% was distributed to households in e.g. Germany, the USA and England via gas pipelines – although not over long distances. Infrastructure elements that were installed at the time, such as pipelines, gas installations, seals, gas appliances etc., were designed for the hydrogen-rich gas and were later modified with the switch to natural gas. Many countries have looked at adding hydrogen into the existing natural gas networks. For the USA, it would be possible to introduce amounts from 5 vol% to 15 vol% hydrogen without substantial negative impact on end-users or the pipeline infrastructure.

At the same time, the larger additions of hydrogen would in some cases require expensive conversions of appliances. In Germany, this limit has been set somewhat lower, at up to 10 vol%. In principle, gas at concentrations of up to 10 vol% hydrogen can be transported in the existing natural gas network without the risk of damage to gas installations, distribution infrastructure, etc. However, a number of components have been listed that are still considered to be critical and to be generally unsuitable for operation with these hydrogen concentrations. For CNG vehicles, the currently authorized limit value for the proportion of hydrogen used is only 2 vol%, depending on the materials built-in.

The different hydrogen transport options each require specific infrastructure and involve a different combination of fixed and operating costs as well as varying levels of transport capacity. Depending on the amount of hydrogen to be transported and the distance over which it needs to be delivered, the most suitable option might change case by case.

As demonstrated in the following chart, because of the lowest investment cost and high variable costs, road transport of gaseous hydrogen is the cheapest option only for short distances and low amounts of hydrogen. The opposite is true for pipelines – fixed costs are driven by high investment costs. Once the pipeline is fully utilised, the variable costs are low. The road transport of liquid hydrogen option is optimal whenever the transportations distances are high but the volume of hydrogen is not sufficient to ensure high utilization of a pipeline.

Figure 35. The cheapest option for hydrogen transportation depending on distance and quantity

Distance in km

Quantity in kg per year	10	50	100	200	300	400	500	600	700	800	900	1,000	1,250	2,000	2,500
100,000	CH2	CH2	CH2	CH2	CH2	CH2	CH2	LH2	LH2	LH2	LH2	LH2	LH2	LH2	LH2
200,000	CH2	CH2	CH2	CH2	CH2	LH2	LH2	LH2	LH2	LH2	LH2	LH2	LH2	LH2	LH2
500,000	CH2	CH2	CH2	CH2	LH2	LH2	LH2	LH2	LH2	LH2	LH2	LH2	LH2	LH2	LH2
1,000,000	CH2	CH2	CH2	CH2	LH2	LH2	LH2	LH2	LH2	LH2	LH2	LH2	LH2	LH2	LH2
2,000,000	CH2	CH2	CH2	CH2	LH2	LH2	LH2	LH2	LH2	LH2	LH2	LH2	LH2	LH2	LH2
3,000,000	CH2	CH2	CH2	CH2	LH2	LH2	LH2	LH2	LH2	LH2	LH2	LH2	LH2	LH2	LH2
4,000,000	CH2	CH2	CH2	CH2	LH2	LH2	LH2	LH2	LH2	LH2	LH2	LH2	LH2	LH2	LH2
5,000,000	CH2	P	P	P	LH2	LH2	LH2	LH2	LH2	LH2	LH2	LH2	LH2	LH2	LH2
10,000,000	CH2	P	P	P	P	P	P	LH2	LH2	LH2	LH2	LH2	LH2	LH2	LH2
15,000,000	CH2	P	P	P	P	P	P	P	P	P	P	P	LH2	LH2	LH2
20,000,000	CH2	P	P	P	P	P	P	P	P	P	P	P	P	P	LH2
25,000,000	CH2	P	P	P	P	P	P	P	P	P	P	P	P	P	P
30,000,000	CH2	P	P	P	P	P	P	P	P	P	P	P	P	P	P
50,000,000	CH2	P	P	P	P	P	P	P	P	P	P	P	P	P	P
100,000,000	CH2	P	P	P	P	P	P	P	P	P	P	P	P	P	P
250,000,000	CH2	P	P	P	P	P	P	P	P	P	P	P	P	P	P
500,000,000	CH2	P	P	P	P	P	P	P	P	P	P	P	P	P	P
1,000,000,000	CH2	P	P	P	P	P	P	P	P	P	P	P	P	P	P
2,000,000,000	CH2	P	P	P	P	P	P	P	P	P	P	P	P	P	P

Source: own elaboration based on [33] [52] [53] [83] [84] [85].

NOTE: CH2 - Road transport of gaseous hydrogen, LH2 - Road transport of liquid hydrogen, P – pipelines

Translating those values into costs, one can see that for low amounts of hydrogen the costs of transportation alone can easily double the cost of hydrogen itself. On the other hand, transportation costs of large quantities over large capacity pipelines can be as cheap as 0.1-0.3 EUR/kg, i.e. even up to 10 times cheaper than transporting energy via electric cables.

It is also clear from the analysis that for the liquified hydrogen option, especially for large quantities, it might be more cost-effective to transport it from production site to port via hydrogen pipelines in gaseous form and liquefy it in port potentially limiting the storage requirements as well.

Figure 36. Costs of hydrogen transportation in EUR per kg as a function of quantity and distance

Quantity in kg per year \ Distance in km	10	50	100	200	300	400	500	600	700	800	900	1,000	1,250	2,000	2,500
100,000	2.021	2.021	2.021	2.021	2.021	2.335	2.817	3.299	3.299	3.299	3.299	3.299	3.299	3.299	3.633
200,000	1.213	1.213	1.213	1.370	1.852	2.273	2.273	2.273	2.273	2.273	2.273	2.273	2.440	3.156	3.633
500,000	0.728	0.728	0.888	1.370	1.658	1.658	1.725	1.820	1.915	2.011	2.106	2.202	2.440	3.156	3.633
1,000,000	0.567	0.646	0.888	1.370	1.534	1.629	1.725	1.820	1.915	2.011	2.106	2.202	2.440	3.156	3.633
2,000,000	0.486	0.646	0.888	1.370	1.534	1.629	1.725	1.820	1.915	2.011	2.106	2.202	2.440	3.156	3.633
3,000,000	0.459	0.646	0.888	1.370	1.534	1.629	1.725	1.820	1.915	2.011	2.106	2.202	2.440	3.156	3.633
4,000,000	0.453	0.646	0.888	1.370	1.534	1.629	1.725	1.820	1.915	2.011	2.106	2.202	2.440	3.156	3.633
5,000,000	0.453	0.613	0.765	1.299	1.534	1.629	1.725	1.820	1.915	2.011	2.106	2.202	2.440	3.156	3.633
10,000,000	0.453	0.461	0.459	0.688	0.968	1.260	1.558	1.820	1.915	2.011	2.106	2.202	2.440	3.156	3.633
15,000,000	0.453	0.410	0.358	0.484	0.662	0.853	1.049	1.247	1.447	1.648	1.849	2.051	2.440	3.156	3.633
20,000,000	0.453	0.384	0.307	0.382	0.509	0.649	0.794	0.942	1.091	1.241	1.391	1.542	1.924	3.069	3.633
25,000,000	0.453	0.369	0.276	0.321	0.418	0.527	0.642	0.759	0.877	0.997	1.117	1.237	1.542	2.459	3.069
30,000,000	0.453	0.359	0.256	0.281	0.357	0.446	0.540	0.636	0.735	0.834	0.933	1.033	1.288	2.051	2.560
50,000,000	0.453	0.348	0.234	0.238	0.292	0.360	0.433	0.508	0.585	0.662	0.740	0.819	1.020	1.623	2.025
100,000,000	0.453	0.345	0.228	0.225	0.273	0.334	0.400	0.469	0.539	0.611	0.682	0.754	0.939	1.494	1.863
250,000,000	0.453	0.323	0.184	0.136	0.140	0.157	0.179	0.203	0.229	0.256	0.283	0.311	0.385	0.607	0.754
500,000,000	0.453	0.319	0.176	0.120	0.117	0.125	0.139	0.156	0.174	0.193	0.213	0.233	0.287	0.450	0.559
1,000,000,000	0.453	0.319	0.176	0.120	0.117	0.125	0.139	0.156	0.174	0.193	0.213	0.233	0.287	0.450	0.559
2,000,000,000	0.453	0.315	0.168	0.104	0.092	0.092	0.098	0.106	0.116	0.127	0.138	0.150	0.184	0.285	0.352

Source: own elaboration based on [33] [52] [53] [83] [84] [85].

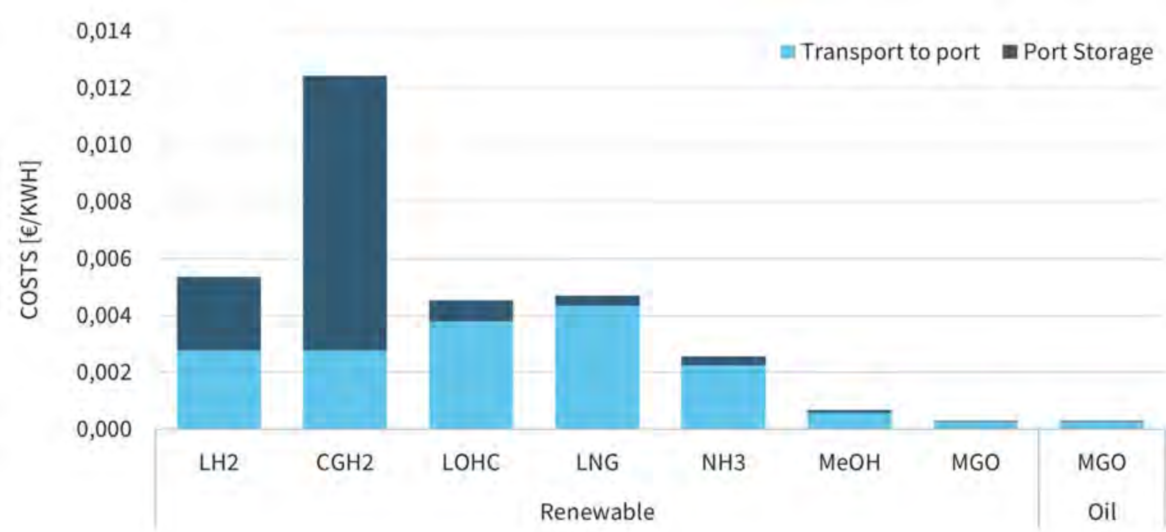
In this study, due to its long term outlook, we have calculated the transportation and storage costs with the assumption that the quantity of transported hydrogen (and other fuels as well) will be big enough to optimize the utilization of assets and reduce the costs. Furthermore, we expect that marine ports are very well suited as a potential location for local renewable hydrogen production – especially from offshore wind. This would greatly reduce the costs of hydrogen transportation. On average, we have assumed around a 50 km distance from fuel production site to port.[23]

Costs of storage were estimated with an assumption that the storage facilities in port would need to be able to hold an amount of fuel sufficient for 5 days of operation.

As can be seen in the graph below, compressed hydrogen is by far the most expensive option both from the point of view of transportation as well as storage and are around 42x higher than for MGO and 6x higher than for LNG. Liquid hydrogen logistics costs are around 15x higher than for MGO and twice as high as for LNG. On the other hand, these costs are a rather small part of the total costs of fuels and are not enough to reduce the overall cost advantage of pure hydrogen option versus synthetic fuels.

[23] For more information on retrofitting natural gas infrastructure to hydrogen see the recent European Hydrogen Backbone report: [52].

Figure 37. Costs of fuel logistics



Source: own elaboration based on [33] [52] [53] [83] [84] [85].

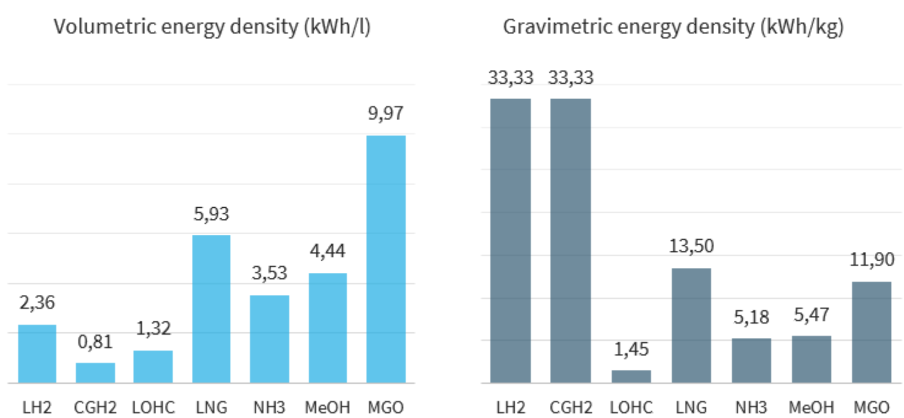
Note: Note that the costs of transportation in the chart below don't include costs of compression or liquefaction of hydrogen, as these costs were already accounted for in the previous step (but are shown in figure 33 for a better depiction of total costs).

5.5 Volume and weight considerations

Hydrogen has relatively lower volumetric density than all other options but while the costs of storage for compressed and liquefied hydrogen are the highest - for short sea shipping applications the additional costs versus e-fuels are manageable and do not outweigh lower production costs of hydrogen.

Other than fuel production costs, the energy density properties of various fuels are the most important factor determining the viability of different options for any given ship type. While the specific energy of hydrogen is almost 3 times higher than MGO's, in terms of energy density per unit of volume pure hydrogen has considerably worse properties than e-fuels.

Figure 38. The cheapest option for hydrogen transportation depending on distance and quantity



Source: own elaboration.

With a volumetric energy density of around 0,81 kWh/l, one cubic meter of hydrogen compressed at 350 bar contains 12 times less energy than a comparable volume of MGO and 7 times less than LNG. One cubic meter of liquid hydrogen contains over 4 times less energy than MGO and 2.5 times less than LNG. In the case of LOHC, while its volumetric energy density is higher than hydrogen at 350 bar, its specific energy is lower than that of all the other options.

Yet, just looking at the energy densities of various fuels does not give the complete picture.

For example, compressed hydrogen is usually stored in cylindrical containers, with relatively thick walls, required to withstand the high pressure, adding around 20% to the fuel volume. If one would consider storing compressed hydrogen in 40-foot containers, then the space lost in between multiple containers as well as the container frame itself would add further space requirements.

In the case of cryogenic fuels like LH2 or LNG, the tanks generally have a double hull design, with a vacuum between the inner and outer container. Besides that, the tanks are rarely filled-up completely in order to leave space for the boil-off gas.

LOHC comes with its own, unique challenges. It can be stored in standard marine fuel tanks but the “spent” carrier, once the hydrogen has been extracted, needs to be also stored onboard. In the case of metal hydrides depending on the reaction needed to extract hydrogen, the spent carrier can require even more space than the “loaded” one (e.g. sodium borohydride). Furthermore, as hydrogen needs to be extracted before it can be used, additional dehydrogenation equipment and hydrogen purification equipment needs to be accommodated as well. Similarly, to be able to use PEM FC in combination with any of the e-fuels, additional fuel reforming/cracking equipment would have to be included in the powertrain setup, increasing the overall space requirements of the system.

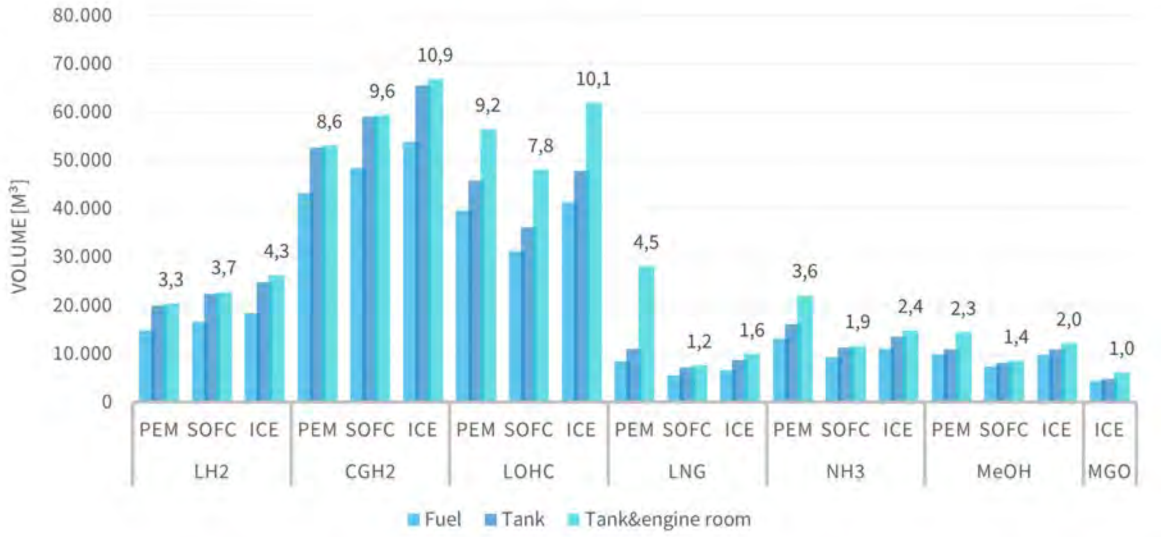
On the other hand, there are also potential gains from using fuel cells. Firstly, fuel cells themselves take up less space than an ICE of comparable power output. Furthermore, using hydrogen in combination with fuel cells allows eliminating the exhaust treatment system, which - especially in multi-deck vessels - might free up a substantial amount of space. Fuel cells are also more energy-efficient than an ICE, making it possible to carry less fuel on board, for the same final energy output. This effect would be further strengthened by the fact, that the efficiency of fuel cells increases in partial load.

All things considered, the exact impact of using alternative fuels on commercial space available on any given ship would need careful examination on a case-by-case basis. For this analysis, however, we have applied several general assumptions to take into account the different requirements of various technologies with regards to the fuel storage system and energy system (fuel reforming and engine or fuel cell) space requirements.[24]

The following figure presents the results of the calculations done for an 8,000–11,999 TEU Containership. The figure shows total space requirements for fuel both in terms of cubic meters as well as relative to an MGO + ICE.

[24] See Annex 4 for details.

Figure 39. Fuel volume (absolute & relative factor to MGO), example calculation for a 8,000–11,999 TEU Containership



Source: own elaboration.

As can be seen, in some cases, the additional space requirements are quite significant. For LOHC, one can see that, although the energy density of the LOHC itself is higher than that of hydrogen compressed to 350 bar, considering the additional buffer tank for dehydrogenated liquid as well as space for the dehydrogenation system, the final space demands are not much better than that of compressed hydrogen. On the other hand, when combining the LOHC with a SOFC, which allows for the possibility of using the fuel cell waste heat to maintain the dehydrogenation process, total space requirements for a system based on LOHC can be greatly reduced.

All options combining synthetic fuels with a PEMFC suffer from similar negative impact from extra space needed for the necessary fuel cracking/reforming/purification step – which is unnecessary for a combustion engine or a high-temperature SOFC, where it is possible to use those fuels directly without prior reforming. In addition to that, in the case of SOFC, using e-fuels instead of pure hydrogen also has benefits in the form of increased efficiency.

All things considered, it is clear, though, that for all options, a switch to alternative fuels will require more space dedicated to the fuel and energy systems that were the case with standard marine fuel oils. This will not only translate into costs of storage tanks and extra equipment but will also impact the ship's capacity to carry passengers and/or cargo.

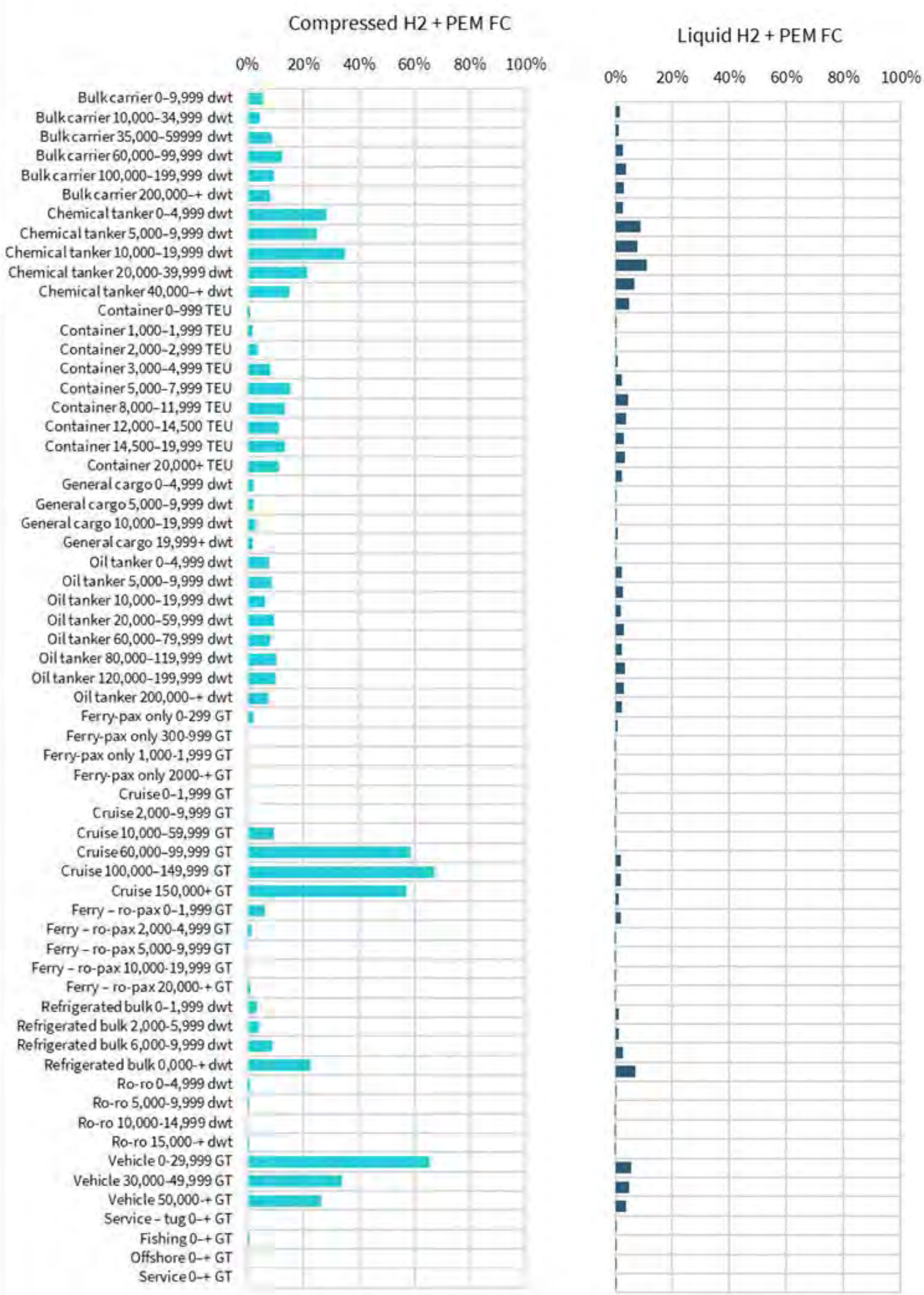
The severity of the impact will, of course, vary and will depend not only on the chosen technology but will also greatly depend on the ship's operational profile. It will be most felt in deep-sea shipping applications, where ships need to be able to travel thousands of nautical miles or for ships engaged in tramp trade without a fixed schedule, requiring additional fuel autonomy to ensure high operational flexibility, which is key for their business model. On the other hand, when ships operate on fixed and relatively short routes, then - even for quite large vessels, like ro-pax ferries – it is possible to use even compressed hydrogen as a solution.

The next graph shows the estimated loss of a ship's payload capacity for two alternative solutions:

- Compressed hydrogen combined with a PEMFC,
- Liquid hydrogen combined with a PEMFC.

It is clear that, compressed hydrogen is not viable for all applications as for most ship types, the loss of cargo is higher than 10-20%, and can be as high as >60%. On the other hand, for liquid hydrogen, in almost no cases is the loss of payload capacity higher than 10%.

Figure 40. The estimated lost payload capacity of ships due to increased volume of the fuel and energy systems.



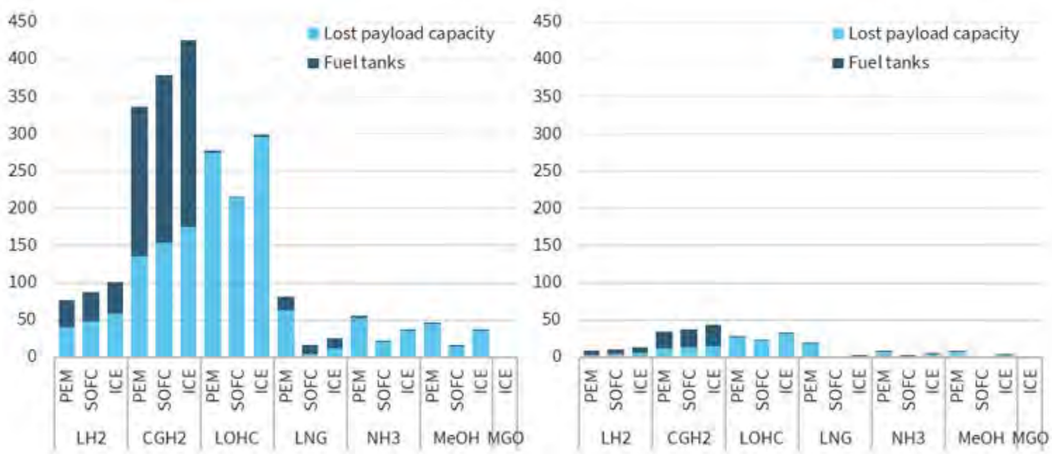
Source: own elaboration.

Consequently, the economic impact of the fuel storage on the total cost of ownership of various ship types will also differ dramatically, especially if one looks at the cost of equipment and tanks and the economic value of lost revenue generation potential.

Considering current freight rates per TEU on certain most common routes or charter rates per day per ship, we have estimated the potential revenue generation capacity per year for each ship type. With those estimations, the next step was to translate the lost payload capacity into lost revenues. This analysis has shown that for most of the ships, the economic impact from lost revenues outweigh the costs of the tanks – even in cases where the storage system is expensive (e.g. compressed and liquefied hydrogen).

At the same time, the analysis has also shown that, while the relative "position" of various options against each other remains the same, the monetary impact for short sea applications is much smaller. In other words, while the costs of storage for compressed hydrogen are always the highest for short sea shipping applications, the additional costs versus other options are much more manageable and do not outweigh the lower production costs of compressed hydrogen.

Figure 41. Estimated economic costs of the onboard energy storage system (in EUR/nm/ship), for an 8,000–11,999 TEU containership (left graph) and a 2000 – 2,999 TEU feeder vessel (right graph)



Source: own elaboration.

It should also be mentioned that there are still plenty of opportunities in the shipping sector to increase the energy efficiency of ships, thus reducing the amount of fuel that needs to be stored onboard and reduce the economic importance of fuel energy density. Technical and operational measures like:

- hull shape optimisation,
- use of lightweight materials,
- air lubrication,
- hull resistance reduction devices,

- ballast water reduction,
- hull coating improvements,
- speed and voyage route optimisation,

can increase the energy efficiency of ships by 20-30%.

Combined with other alternative power solutions like e.g. wind assistance, these measures can be therefore seen as enablers for clean sustainable fuels uptake in the maritime sector.

5.6 Energy conversion

The higher energy efficiency of fuel cells compared to internal combustion engines can partially offset its lower volumetric energy density.

The impact of fuel cells CAPEX on the Total Cost of Ownership is relatively small.

The energy conversion step includes both the fuel transformation/conditioning onboard (if needed) and the power generation.

Using LOHC (as well as metal hydrides) for energy storage onboard will require dehydrogenation equipment to first 'extract' hydrogen from the hydrogen carrier. This, of course, adds to overall costs but also contributes to higher space requirements – not only for the dehydrogenation unit but, in case of no waste heat being available, also for the extra fuel needed to maintain the dehydrogenation process. Similar problems occur for all synthetic fuel options if coupled with PEMFC, which require high purity grade hydrogen as a fuel. This makes high-temperature SOFC a preferable option for use with ammonia and other synthetic fuels.

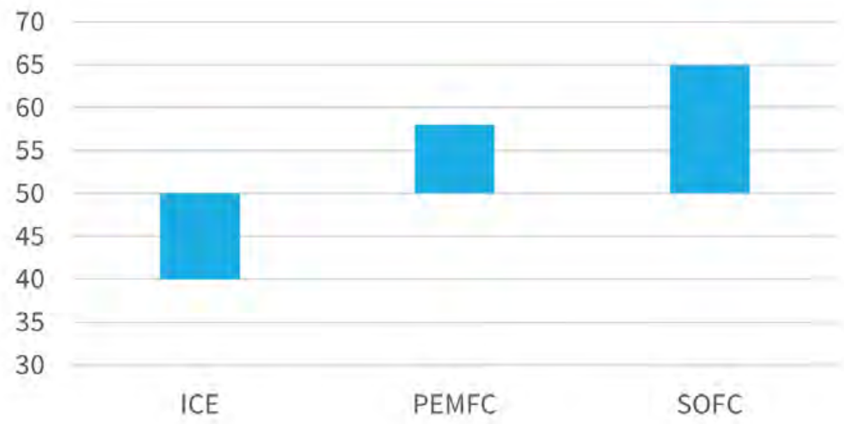
On the other hand, with their higher electrical efficiency when running on pure hydrogen, coupled with lower CAPEX, faster start and ramp-up time, PEMFC look set to be the optimal solution to be used with compressed and liquefied hydrogen.

For power generation, we include an internal combustion engine and two types of fuel cells: Polymer electrolyte membrane fuel cells (PEMFC) and Solid oxide fuel cells (SOFC). Fuel cells use the chemical energy of fuels such as hydrogen, ammonia or hydrocarbon gas to produce electricity and thermal energy. If fuel cells use hydrogen directly, the only emitted byproduct is water, i.e. there are no emissions of GHG or any air pollutants, such as NOx, SO2 or PM.

Fuel cells have a high electrical generation efficiency compared to most other generator technologies (reciprocating engines, gas turbines without combined condensing cycles). The efficiency of a gas-fueled internal combustion engine is around 42-45% for small units and up to 48-50% for large multi-MW engines, with a couple of percentage points lower efficiencies when fuelled with liquid fuel oils. The electrical efficiency of PEMFC is usually around 50-56%, and in the case of SOFCs electrical efficiencies of over 70% [25] on a stack level and over 60% on a system level has been demonstrated.

It should also be noted that, while internal combustion engine technology is mature and expected future efficiency improvements are limited, the efficiency of fuel cells is expected to go up considerably. According to the Strategic Research and Innovation Agenda of the foreseen Clean Hydrogen for Europe Partnership,[26] prepared by Hydrogen Europe and Hydrogen Europe Research, the target of research is to reach electrical efficiencies of 58% for PEMFCs and 65% for SOFCs by 2030. [57]

Figure 42. Electrical efficiency comparison of an internal combustion engine with PEMFCs and SOFCs



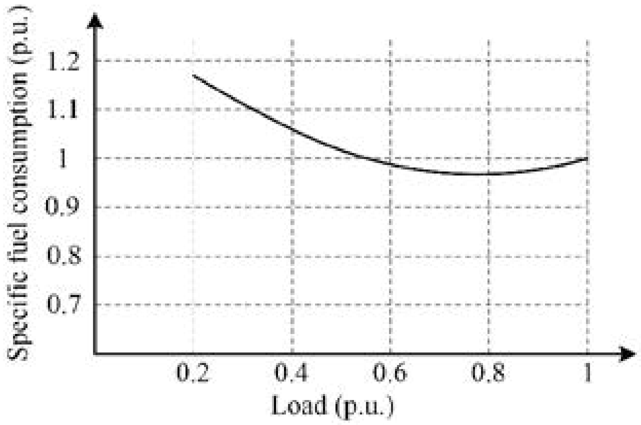
Source: own elaboration.

Yet, it needs to be remembered that fuel cells generate electricity directly, while internal combustion engines generate primarily mechanical energy. Therefore, whenever electricity is needed, ICE has to convert the energy in the fuel first into mechanical energy and then into electrical energy, further reducing the efficiency. This increases the efficiency advantage of fuel cells for use as a source of auxiliary power or as main power for large ships, which use diesel-electric powertrains (e.g. cruise ships). Conversely, for propulsion needs, the advantage of fuel cells would be slightly diminished by the need to convert electrical energy to mechanical energy via an electric motor.

Another difference in favour of fuel cells in the shape of the load-efficiency curve. The maximum efficiency is usually reached at around 0,7 – 0,85 of rated power for internal combustion engines, but at loads below 50%, the ICE efficiency starts to drop sharply.

25 https://www.fch.europa.eu/news/performance-sofc-stack-breaks-record-thanks-project-nellhi
26 The third EU public-private partnership, continuation of the FCH2JU. The Strategic Research and Innovation Agenda is made of a set of 21 roadmaps. This SRIA represents the view of the private partner and will be used as a basis to develop the Multi Annual Work Plan (MAWP) of the Clean Hydrogen for Europe partnership. The current version (July 2020) is the final draft that has been submitted to the European Commission and is available at https://hydrogeneurope.eu/clean-hydrogen-europe.

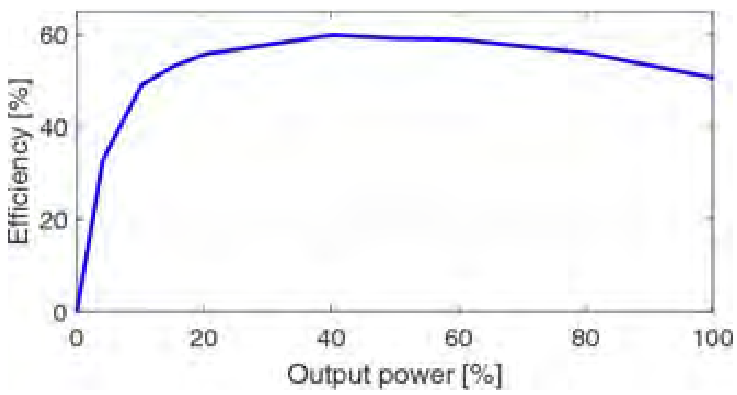
Figure 43. Typical specific fuel consumption curve of a marine diesel-engine



Source: [58].

This is not the case with fuel cells, which have a much flatter efficiency curve, which starts to drop below its level at maximum power only below 10% of load. Furthermore, within the entire load range between 20%-90% of rated power, the efficiency of a fuel cell is higher than at maximum power, which gives higher operational flexibility than an internal combustion engine.

Figure 43. Typical specific fuel consumption curve of a marine diesel-engine



Source: [59].

Fuel cells also have other advantages over combustion engines: they have no moving parts – as a result, they are quiet, require no oil changes and minimal maintenance. Fuel cells are also easily scalable, as individual cells can be stacked together to provide a wide range of power.

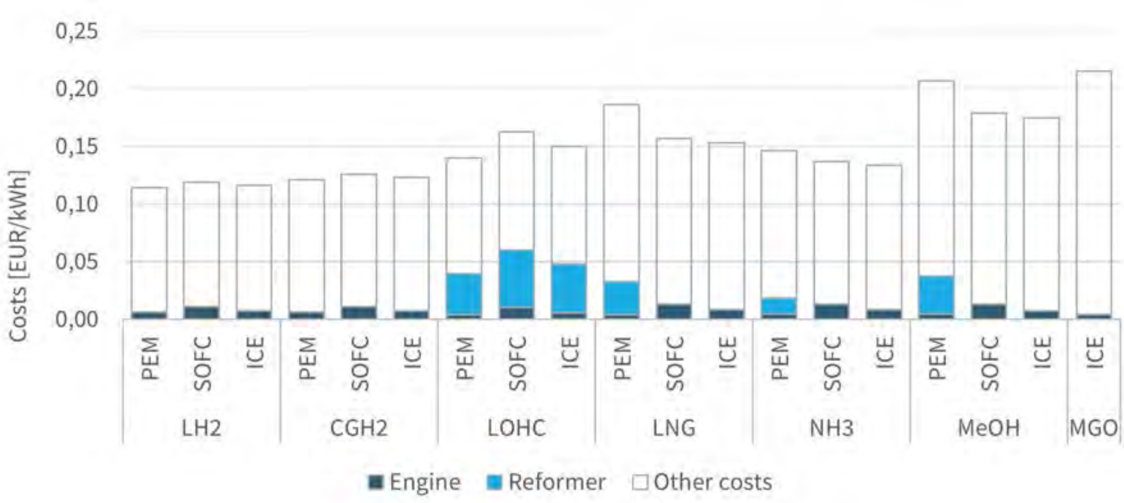
Another consideration is the heat supply. PEMFC typically operates at about 80°C, which is not high enough to provide a meaningful source of thermal energy. As a result, ships with significant heat demand would need an additional hydrogen boiler. SOFCs operate at much higher temperatures - typically 800°C to 1,000°C – and, as such, can cover the heating demand as well. On the other hand, high temperatures make rapid start-up challenging, while PEMFC can respond quickly to changing loads.

So far, fuel cells have been deployed mostly as small scale CHP or in road mobility applications. Researchers have developed these components to the point where they have the operational reliability to allow them to be deployed in small series production to mainstream vehicle customers (1,000s of units in the US and Asia); the main driver for fuel cell technology in Europe is heavy-duty applications (over 1,600 buses to be deployed). The fuel cell stacks operating in London's buses since 2010 have lasted for over 25,000 hours, thereby proving their possible longevity in a heavy-duty vehicle, at least for this specific usage.

The challenge now is to reduce cost through a combination of increased production volume as well as technology development to improve and automate production techniques, reduce material costs per unit of output (specifically, costs of precious metals used as catalysts in fuel cells and carbon fibre in tanks) and improve designs at stack (e.g. catalyst layers) and system BoP components level (e.g. air loop). Although, as demonstrated in the graph below, **the impact of fuel cell / ICE cost on the Total Cost of Ownership is rather small** in comparison to other elements, like fuel costs and cost of storage (including impact on ships' payload capacity).

The onboard fuel reforming system has a much higher impact on TCO than the engine/fuel cell. Even though the costs of those systems are likely to fall following an increase in production volume, they are likely going to remain relatively expensive because, unlike fuel cells, the demand for those systems outside of the maritime sector will most likely remain limited, and because of fuel cell losses, the fuel reforming system needs to have twice the power output than the fuel cell it used to supply fuel to.

Figure 45. Energy conversion system cost comparison.



Source: own elaboration.

5.7 Total costs of ownership comparison

Out of all analysed options, only three came out as the most cost-efficient: Compressed or liquefied hydrogen with PEMFC and ammonia with SOFC.

By far, the highest market share belongs to green ammonia with 91.4% with liquefied hydrogen's share at 8,6%, and compressed hydrogen's below 0.1%.

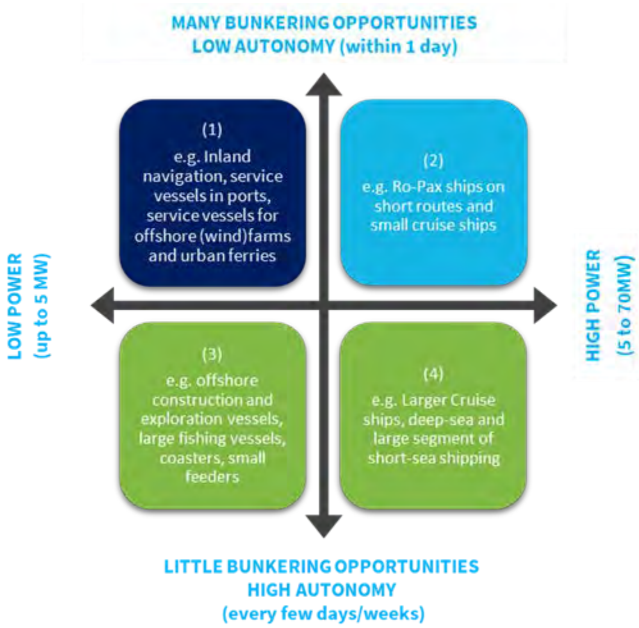
The current ETS carbon price would not be a high enough incentive for fuel switch.

The shipping sector involves a wide range of use cases, with both the autonomy and power requirements of small vessels and large cruise ships differing by three orders of magnitude. This highlights the importance of defining different strategies for zero-emission propulsion for each vessel type. For this analysis, we have distinguished four different groups of vessels based on their power requirement and refuelling frequency:

- **Type 1** – ships with both low power requirements (up to 5 MW) and many bunkering opportunities, resulting in low onboard energy storage demand, including (among others) inland ships, service vessels in ports, urban ferries, service vessels for offshore.
- **Type 2** – large vessels with substantial power requirements but operated on short routes with frequent refuelling possibilities, including (among others) RO-PAX ferries and small cruise ships.
- **Type 3** – relatively small vessels with limited power requirements but which operate on longer routes or as 'tramp trade' vessels and thus have limited refuelling opportunities. Includes (among others) offshore construction and exploration vessels, large fishing vessels, feeders.
- **Type 4** – large ships operating on long routes with both high power and energy storage requirements. This category includes (among others) large cruise ships and deep-sea shipping (VLCCs, VLBCs and large containerships).

Figure 46. Simplified segmentation of the maritime sector

Source: own elaboration.



The results of the analysis vary for each of the ship type group.

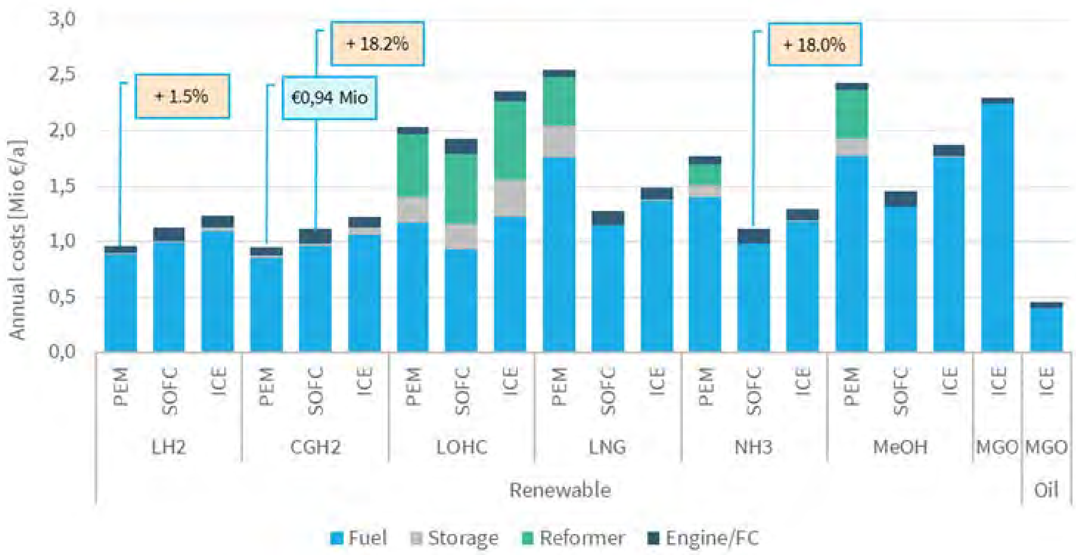
5.7.1 Type 1 – Low power and low energy storage requirements

The analysis shows that for **Type 1 ships compressed hydrogen option is the most cost-competitive.** This is not surprising as Type 1 covers small ships navigating on fixed routes and urban ferries with the possibility of relying on fixed bunkering points along their routes. Onboard, storage will not be an issue because of shorter/fixed routes. In many cases, onshore fuel cell technology and Hydrogen Refuelling Stations (HRS) can be used or adapted. Fuel distribution networks will enable the introduction of new and retrofitted ships. Also, service vessels in ports and vessels bringing the crew to offshore wind farms can be served with a dedicated "back to port" fuelling infrastructure and thus do not require large onboard energy storage.

It should also be noted that although compressed hydrogen is the cheapest option, its lower production costs are somewhat reduced by higher proportions than in other options costs of fuel logistics, and as a result, the costs of liquefied hydrogen are only slightly higher. Ammonia option is 18% more expensive and the cheapest of e-fuels (e-LNG) is 50% more expensive than pure hydrogen options. Even the cheapest hydrogen option is more than twice as expensive as MGO (at 500 USD/t).

As neither compressed nor liquefied hydrogen needs any reforming, PEMFC is the preferred energy converter due to its lower price.

Figure 47. TCO analysis (in M€ p.a.) for Type 1 vessel (e.g. 1,000-1,999 GT passenger ferry)



Source: own elaboration.

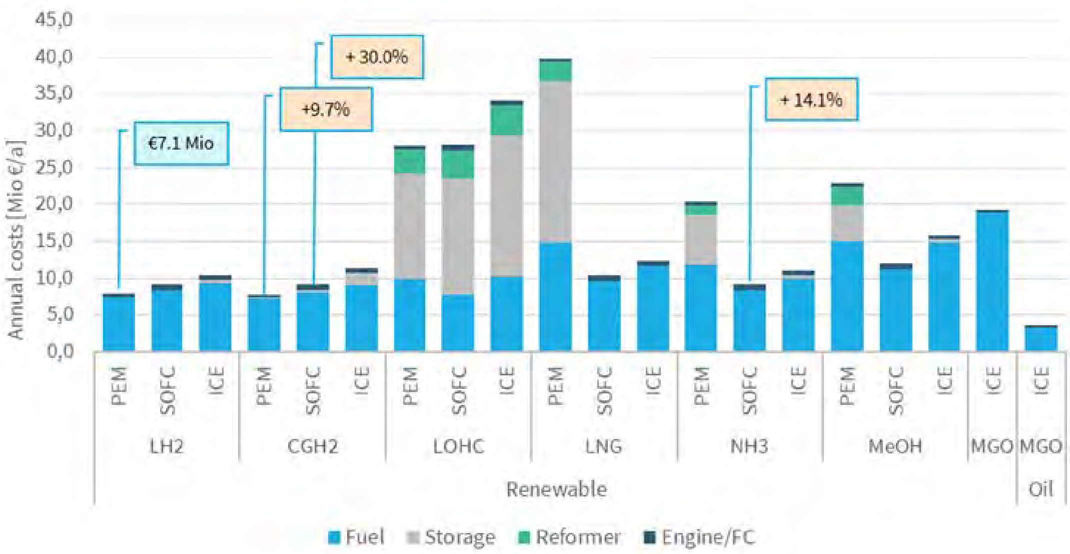
5.7.2 Type 2 – High power and high refuelling frequency

For Type 2 vessels, liquefied hydrogen is the most cost-competitive option by a significant margin. This category includes among others ROPAX (roll-on/roll-off passenger)[27] ships. Larger power generation units will be required (from 1MW to 15-25MW), however with limited autonomy, as these ships usually operate on a sea link between fixed two ports. This makes it relatively easy to provide the necessary bunkering infrastructure and will make these ships the likely first adopters (along with type 1 vessels), especially for liquefied hydrogen solutions.

In an example 10,000 – 19,999 GT Ro-Pax ferry, liquefied hydrogen is around 10% less expensive than the next best option (compressed hydrogen), 14% less expensive than ammonia and 30% less expensive than e-LNG. On the other hand, it is twice as expensive as MGO.

For this sector to start adopting hydrogen as a fuel, important regulatory issues still need to be addressed and upscaling to these high-power generation units will require new technology developments. Together with the fact that construction costs of these vessels can reach hundreds of million euros, unless heavily subsidized, the development of Type 2 hydrogen-powered vessels will probably be delayed until the barriers are removed and Type 1 vessels successfully demonstrate the reliability of hydrogen solutions, both ashore and onboard.

Figure 48. TCO analysis (in M€ p.a.) for Type 2 vessel (e.g. 10,000-19,999 GT RO-PAX ferry)



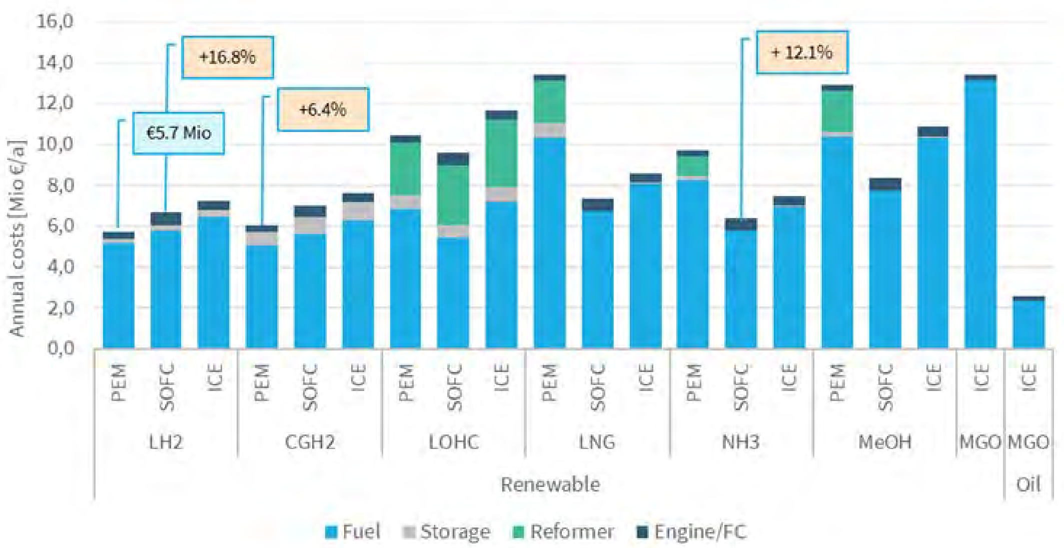
Source: own elaboration.

27 a RORO vessel built for freight vehicle transport along with passenger accommodation

5.7.3 Type 3 – Low power and high autonomy requirements

The results for type 3 vessels are not much different from type 2, with liquefied hydrogen the most cost-competitive zero-emission option. The example of a feeder vessel transporting containers over a predefined route regularly, shows LH2 being 6% less expensive than compressed hydrogen, 12% than ammonia, and more than 20% than e-LNG.

Figure 49. TCO analysis (in M€ p.a.) for Type 3 vessel (1,000 – 1,999 TEU feeder)



Source: own elaboration.

That being said, it should be noted that this category is quite diverse. It also includes offshore (exploration and construction) vessels, that are designed to serve operational purposes such as research and construction work at the high seas. These ships are generally characterized by reduced hull dimensions and a very high number of systems and equipment onboard. Power needs are therefore dominated by propulsion and the operation of onboard equipment. These vessels could be served in distinct clusters (e.g. from a fishing port) to minimize infrastructure costs. Nevertheless, these ships will still require considerable onboard energy storage, which – combined with limited space available for extra fuel storage, makes energy dense synthetic fuels an option – even if more expensive.

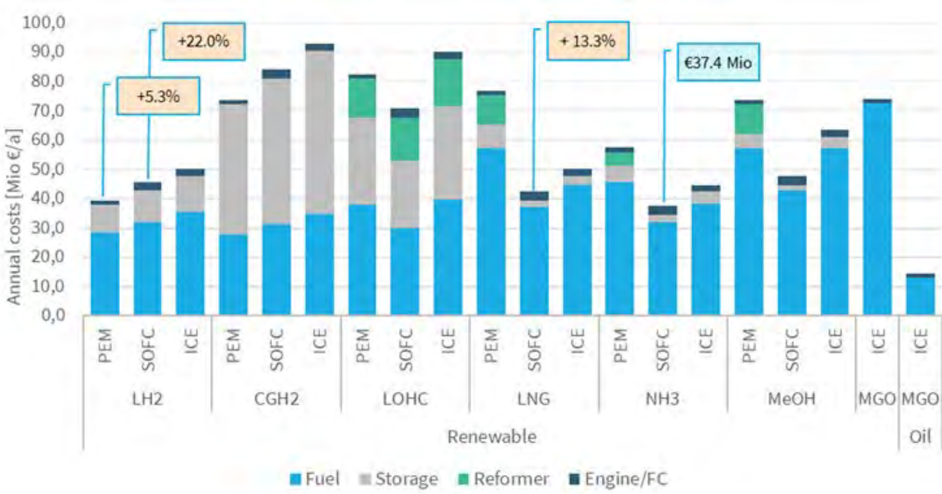
5.7.4 Type 4 – High power and high energy storage requirements

This category encompasses the entire deep-sea shipping sector, which is responsible for most of the maritime traffic and GHG emissions. These are ships requiring large power (up to 50-70MW) and large autonomy of up to two weeks, enabling them to cover 10,000 – 12,000 nautical miles on one tank.

They will be the most complex vessels to power with fuel cells, and initial development will focus on hotel loads, before increasing to partial power, these ships are likely to be one of the final adopters of a full technology switch in the maritime sector. There will need to be an international agreement with respect to fuel choice to ensure bunkering is available in all the ports served along the shipping routes.

This conclusion is further strengthened by the fact that for this type of vessels, the TCO analysis has shown that the most cost-effective option is ammonia coupled with SOFC, which are relatively low on TRL for maritime applications, especially in the power requirements are measured in tens of MWs.

Figure 50. TCO analysis (in M€ p.a.) for Type 4 vessel (20,000+ TEU container ship)



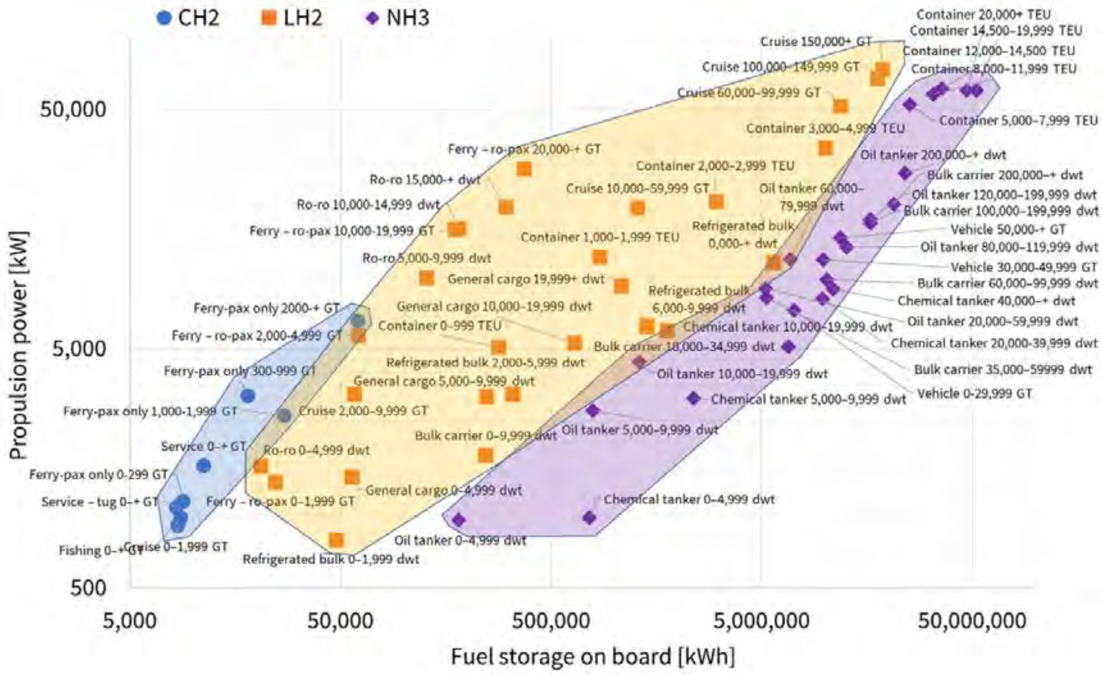
Source: own elaboration.

5.7.5 Summary

When repeating the exercise for all 61 ship types in the database, what the results show is that out of all analysed options, only three came out as the most cost-efficient:

- Compressed hydrogen with PEM FC for relatively small ships with an operational profile allows for frequent refuelling, limiting the required amount of fuel that needs to be stored onboard.
- Ammonia with SOFC for deep-sea shipping applications or smaller vessels with high-value cargo (e.g. chemical tankers), for which storing enough energy using low energy density fuels like compressed hydrogen is not possible, or the payload is so valuable that it is profitable to use a more expensive synthetic fuel to limit revenue loss.
- Liquefied hydrogen with PEMFC for every ship in between. This option seems to give the optimum balance between fuel cost and energy density, and as long as the impact of its relatively lower energy density versus synthetic fuels on payload capacity loss is not excessively high, it is the most cost-effective option for most ships.

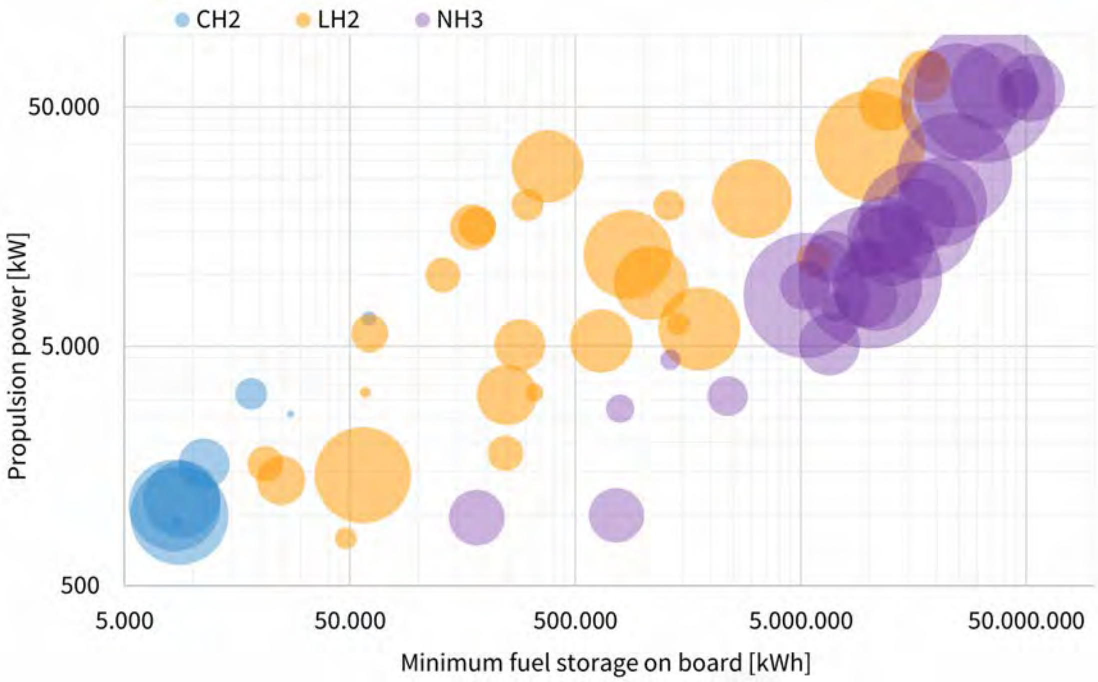
Figure 51. Optimum zero-emission option for various ship types



Source: own elaboration.

While liquefied hydrogen seems to be the optimal solution for most ships, in terms of total energy demand, both compressed and liquefied hydrogen are dwarfed by synthetic fuels (e-ammonia). 91.4% of all fuels would be used by ships running on e-ammonia with liquefied hydrogen's share at 8,6% and compressed hydrogen below 0.1%.

Figure 52. Optimum zero-emission option for various ship types and their relative total energy demand (size of the bubble)

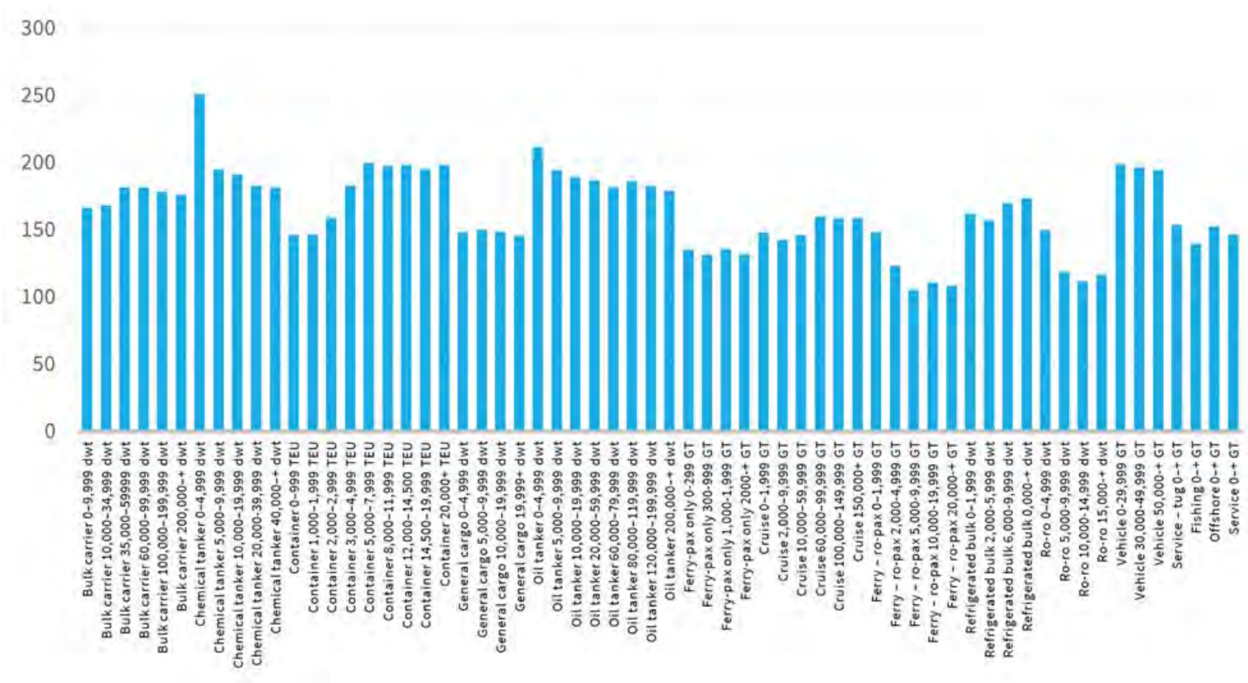


Source: own elaboration.

The overall costs of all options for every ship type are well above the fossil fuel option (MGO at 500 USD/t). This is of course not unexpected, given the low fossil fuels costs, supported by low to non-existent taxation on marine fuel oils. The cost difference is one of the key barriers that need to be tackled to see a real uptake of zero-emission fuels in the maritime sector, which would go beyond just demonstration projects, and could have a real impact on reducing the sector's GHG emissions. Some of the ways of overcoming the cost difference, currently under consideration in the EU, is to on one hand to impose a zero-emission obligation quota on ship operators or to impose a carbon price on marine fuels.

While this paper is not focusing on policy options but given the ongoing discussion about the possibility of including the maritime sector in the EU Emission Trading System, it is interesting to look at what would the carbon price needed for the zero-emission fuels to reach cost parity with conventional marine fuel oils. The results of this analysis are shown in the figure below.

Figure 53. Minimum CO2 price to reach a break-even point

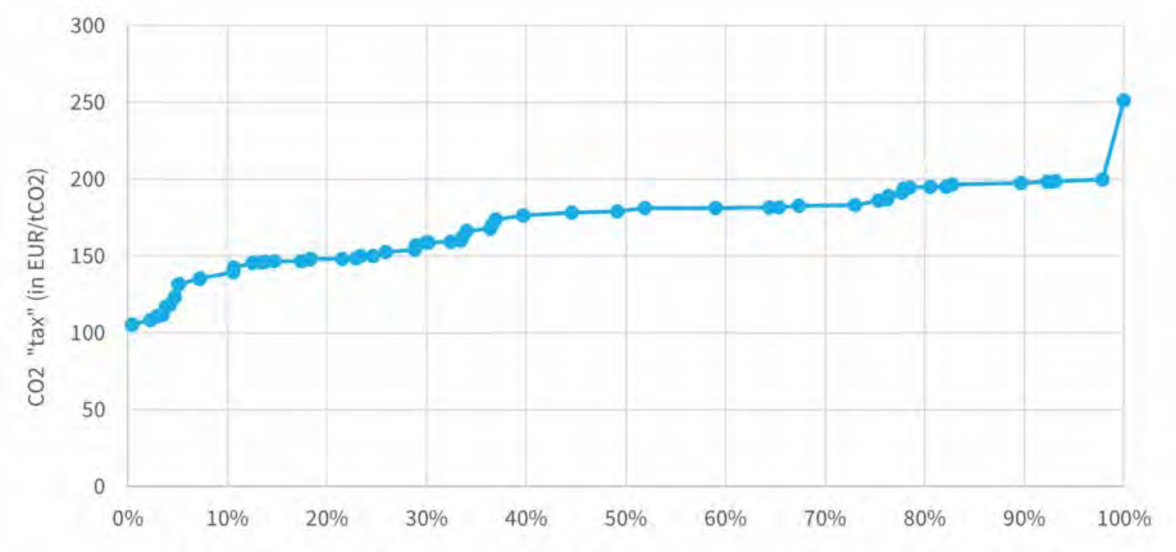


Source: own elaboration.

As the analysis shows, depending on ship type, for the CO2 price to provide a sufficient incentive to switch from fossil fuel oils to zero-emission fuels, it would have to be between EUR 100 per tonne of CO2 to EUR 250 per tonne of CO2. CO2 price of around EUR 150 per tonne would be needed for a fuel switch of ships responsible for around 25% of GHG emissions, while EUR 180 per tonne would be needed to achieve around 75% reduction. Given that one tonne of marine fuel oil, when combusted, emits around 3.1 tCO2, a carbon price of 180 EUR/tCO2 would mean extra fuel costs of around 560 EUR/t.

This is of course well above the current EU ETS CO2 emission allowance price of around EUR 25 per tonne of CO2 (78 EUR/t of fuel). As a result, the inclusion of the maritime sector in the ETS cannot be the only measure taken at the EU level to accelerate the decarbonisation of shipping.

Figure 54. Cumulated shipping CO2 emission savings as a function of the carbon tax



Source: own elaboration.

On the other hand, the EU ETS carbon price would still impose around a 40x higher carbon tax on fuels than the proposed R&D fund proposed by the International Council of Shipping, which assumes contributions of USD 2 per tonne of fuel consumed by every ship.

It should also be noted that such high costs of alternative fuels, equal to an increase in fuel costs of over 500 EUR/t, seem excessive, the impact on total costs of goods shipping will not be very drastic. In the case of a VLCC carrying coal from Australia to Europe, a switch to zero-emission fuels would translate into an increase in the costs of shipping by only 6,4 EUR/t. In the case of containerships carrying cell phones from China to Europe, this would add little more than 3 cents to the price of each phone. This demonstrates that a switch to zero-emission fuels is not only possible but does not seem likely to be detrimental to world trade.

6. Results sensitivity analysis

As is the case with every analysis of this kind, it is heavily influenced by a number of key assumptions, which bring a considerable amount of uncertainty to the results. In the following chapter, we have analysed the extent that those key assumptions can influence the results to reduce this uncertainty. The identified key risk factors include:

- Hydrogen production costs;
- Hydrogen liquefaction costs;
- Hydrogen logistics costs;
- The combined implementation of zero-emission fuel switch and measures reducing the overall ship energy demand (e.g. wind assistance).

6.1 Hydrogen production costs

Hydrogen production costs affect all options equally, so even a drastic change in production costs does not change the relative 'score' of various options but only impacts the cost gap compared to conventional fuels.

As mentioned before, this analysis assumes that hydrogen used as a fuel or as feedstock to produce e-fuels would be of renewable origin - produced via water electrolysis using renewable electricity, at the cost of around 2.4 EUR/kg. While this is a level that would be hard to achieve today in Europe, at least outside of a limited number of locations in Southern Europe with extremely good solar irradiation, by 2030, we expect that due to continuous technology developments leading to reduction of electrolyser CAPEX coupled with a continuation of the downwards renewable energy costs trend, this cost level to be attainable in most of the EU. More long-term, renewable hydrogen is expected to be cost-competitive, with even fossil fuel-based hydrogen reaching production costs of around 1.0 – 1.2 EUR/kg. The graph below shows the impact that a fall of electrolyser CAPEX and reduction of renewable energy LCOE would have on the production costs of hydrogen.

Figure 55. Renewable hydrogen production costs (in USD/kg) depending on CAPEX, electrolyser load factor and renewable energy LCOE

< USD 2/kg | USD 2-3/kg | USD 3-4/kg | > USD 4/kg | Viable medium-term (<2030)

LCOE \ Capex electrolyser	USD 750/kW					USD 500/kW					USD 250/kW				
UDD 0/MWh	5.7	2.8	1.9	1.4	1.1	4.2	2.1	1.4	1.1	0.9	2.8	1.4	0.9	0.7	0.6
USD 10/MWh	6.1	3.3	2.4	1.9	1.6	4.7	2.6	1.9	1.5	1.3	3.2	1.9	1.4	1.2	1.0
USD 20/MWh	6.6	3.8	2.8	2.4	2.1	5.2	3.0	2.3	2.0	1.8	3.7	2.3	1.9	1.6	1.5
USD 30/MWh	7.1	4.2	3.3	2.8	2.5	5.6	3.5	2.8	2.5	2.2	4.2	2.8	2.3	2.1	2.0
USD 40/MWh	7.5	4.7	3.8	3.3	3.0	6.1	4.0	3.3	2.9	2.7	4.6	3.2	2.8	2.6	2.4
USD 50/MWh	8.0	5.2	4.2	3.7	3.5	6.5	4.4	3.7	3.4	3.2	5.1	3.7	3.2	3.0	2.9
USD 100/MWh	10.3	7.5	6.5	6.1	5.8	8.9	6.7	6.0	5.7	5.5	7.4	6.0	5.6	5.3	5.2
Load factor	10%	20%	30%	40%	50%	10%	20%	30%	40%	50%	10%	20%	30%	40%	50%

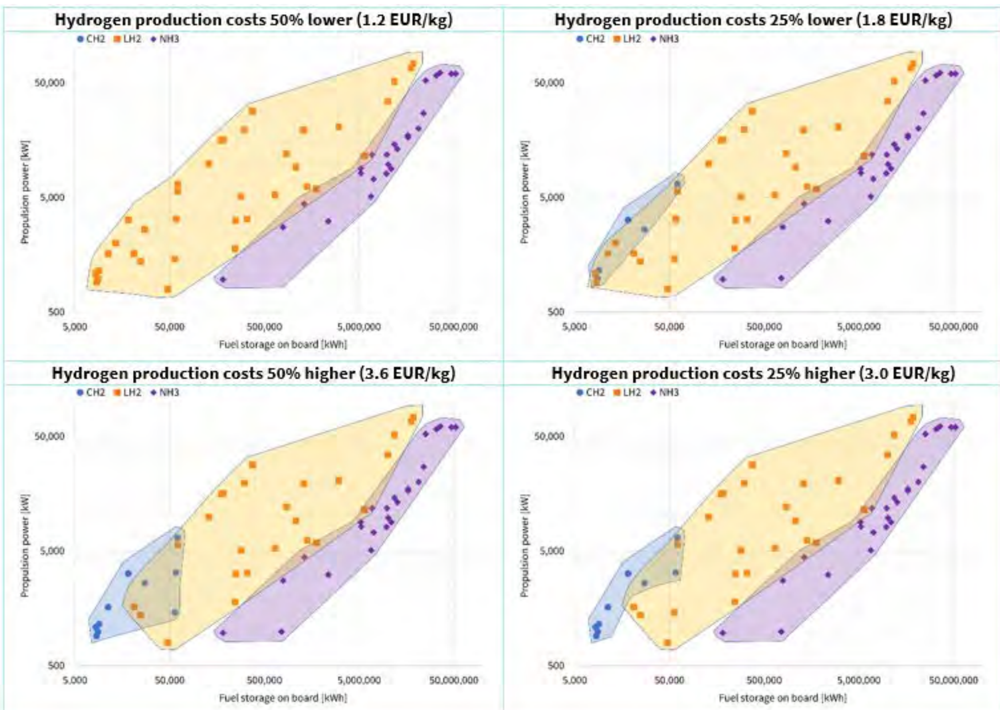
Source: [62].

Furthermore, there are many more ways of producing clean hydrogen, including steam or autothermal reforming of natural gas with carbon capture and storage, reforming of biogas/biomethane, gasification of biomass or waste, and water electrolysis using nuclear electricity. All those pathways have their own cost dynamic and may prove to provide an even cheaper hydrogen supply opportunity.

Considering all the above, we have done an analysis showing what the results of the analysis would be if hydrogen production costs would significantly differ from the one assumed in the base analysis.

Figure 56. The sensitivity of results to changes in hydrogen production costs

Source: own elaboration



As can be seen in the graphs above, even a dramatic fall or increase in clean hydrogen production costs would not change the results significantly. This is because hydrogen production costs affect all options to a similar degree. The only reason why there is any change at all, is mostly because - as electricity costs are the single most important factor deciding costs of renewable hydrogen - we have assumed that costs of electricity used in other steps of fuel production (e.g., compression, liquefaction etc.) would also change accordingly in each scenario. So, a drop in hydrogen production price is accompanied by a drop in hydrogen liquefaction costs, which makes it more cost-competitive versus compressed hydrogen.

But, while a change in hydrogen production costs would not have a big impact on the relative ‘score’ of each option, it would, of course, have a huge impact on the difference between the zero-emission options and conventional fuel oils. Hydrogen production costs at 3.6 EUR/kg would increase the break-even carbon price for 75% of ships from 180 to 250 EUR/t CO2, meaning an increase in fuel costs of around 750 EUR/t of MGO. At the same time, hydrogen production costs at 1.3 EUR/kg would decrease the break-even carbon price to around 80 EUR/t (extra fuel costs of 240 EUR/t), and for some ship types (e.g. Ro-Pax ferries) would be low enough to reach cost parity with fossil fuels without any subsidies or carbon price.

6.2 Hydrogen liquefaction costs

Increasing the size of liquefaction plants will lead to liquefaction cost reduction that would make it the most cost-efficient option for all short sea shipping applications and also be cost-competitive with green ammonia as a fuel for deep sea shipping.

As the market for liquefied hydrogen in the EU today is limited to a number of niche applications, all the hydrogen liquefaction facilities in Europe are of a rather small scale with a capacity of 5 – 10 tonnes per day (TPD). If there was a large scale demand for liquefied hydrogen from the maritime sector it would make it viable to construct liquefaction facilities with capacities of an order of magnitude larger. This would enable to not only reduce the CAPEX per unit of production but also would lead to a significant reduction in energy intensity of the liquefaction process bringing it down from around 10 kWh per kg of hydrogen to even 6 kWh per kg – leading to a decrease of specific liquefaction costs even by 2/3 compared to current state-of-art.

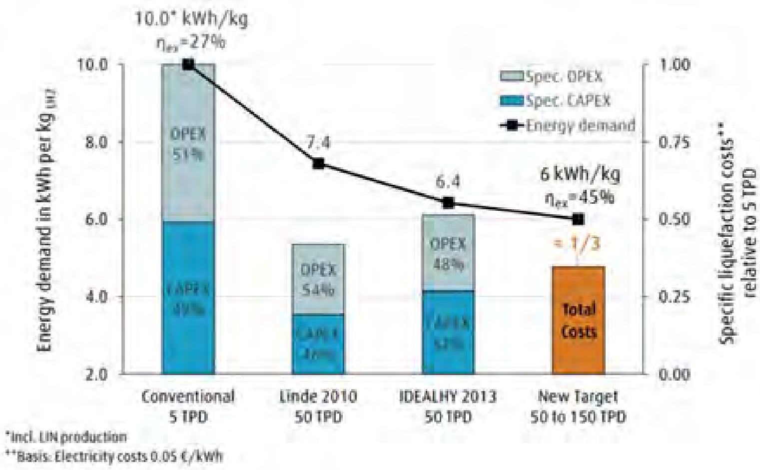
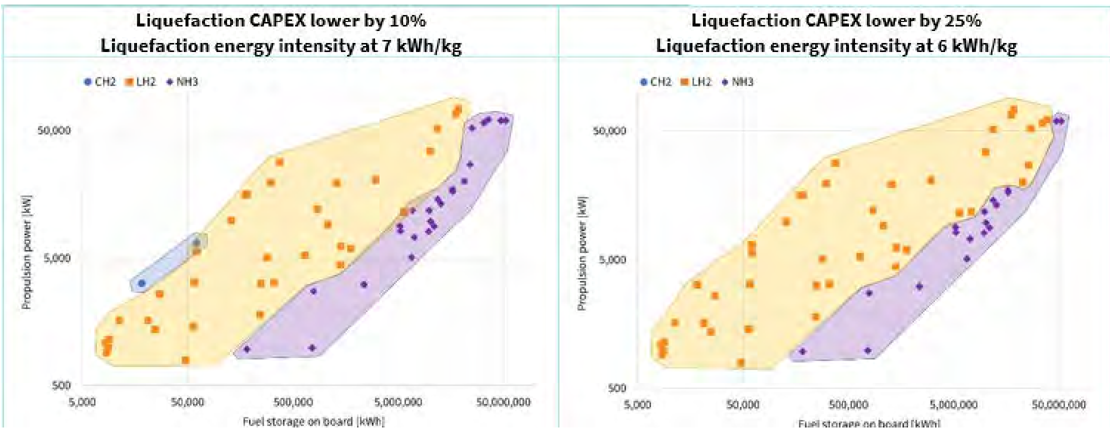


Figure 57. Current and projected liquefaction costs and efficiencies.

Source: [54].

As shown on the graphs below, this would make liquefied hydrogen the most cost-efficient option for all short sea shipping applications and also be cost-competitive with green ammonia as a fuel for deep sea shipping.

Figure 58. The sensitivity of results to changes in hydrogen liquefaction costs



Source: own elaboration.

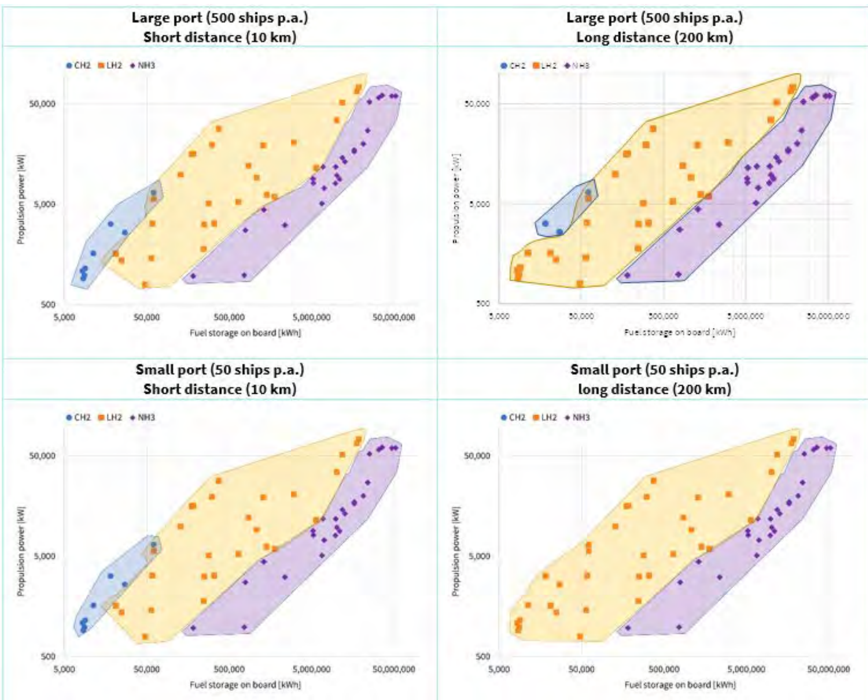
6.3 Logistics cost

Due to the relatively low volumetric energy density of hydrogen, costs of logistics will play a key role in deciding the viability of various business cases for the use of zero-emission fuels. As this analysis focuses on long term viability assessment, it was assumed that the fuel would be transported to ports over relatively short distances (50 km) and in high quantity, enabling economies of scale to bring costs down. But this will not be possible right from the start when demand will be low and renewable production sites scarce. This also will not be possible for every small port with a low number of waterborne traffic.

The figure below shows the impact on the analysis results from a change of both distances over which the fuels would have to be distributed as well as the quantity of transported fuel.

Figure 59. The sensitivity of results to changes in fuels logistics costs

Source: own elaboration



As shown in the graphs above, for compressed hydrogen to be a viable option for even short routes, hydrogen production needs to be relatively local. If the hydrogen production plant is remotely located then unless the demand for hydrogen is high, compressed hydrogen will not be cost-competitive with other options.

7. List of figures

8. List of tables

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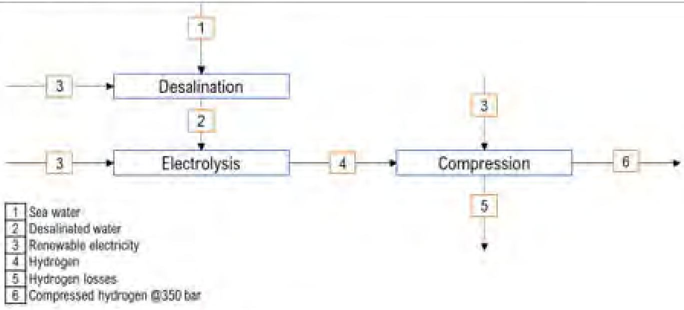
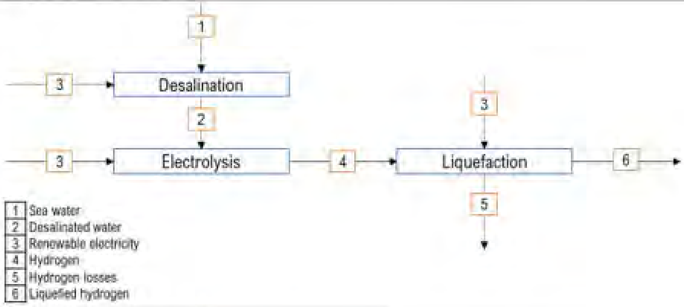
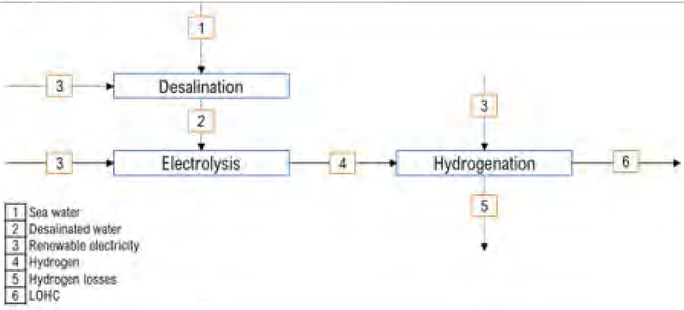
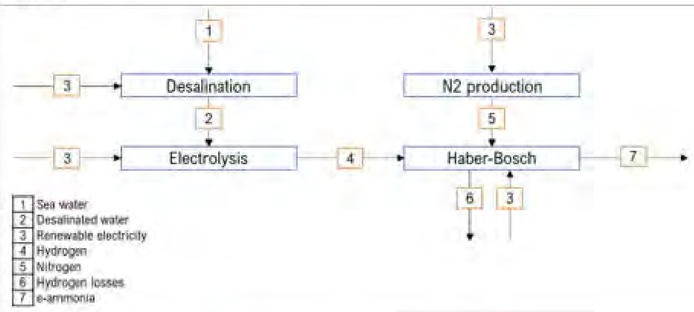
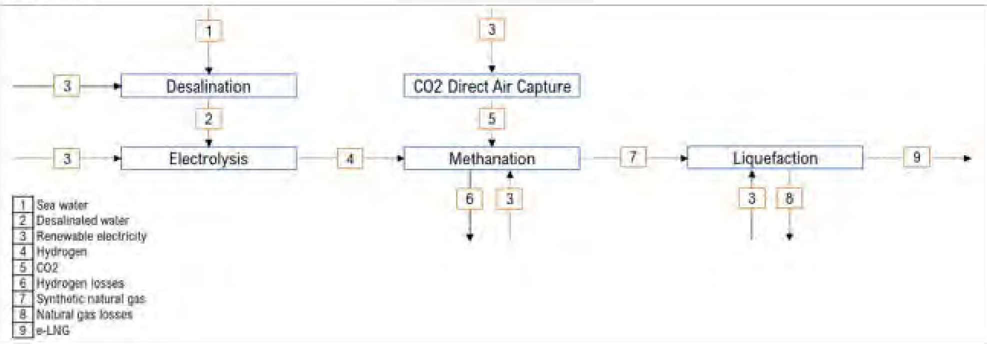
10. Annex

10.1 Annex 1: Fuel production pathways

Table 5. Fuel production process

#	Option	Process
1	Renewable compressed hydrogen	
2	Renewable liquified hydrogen	
3	Renewable hydrogen stored in LOHC	
4	Renewable e-ammonia	
5	Renewable e-LNG	

10. Annex

<table>
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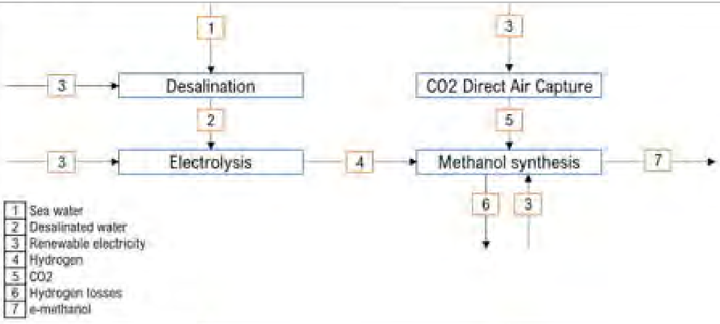
<tr><td>6</td><td>Renewable e-methanol</td><td>
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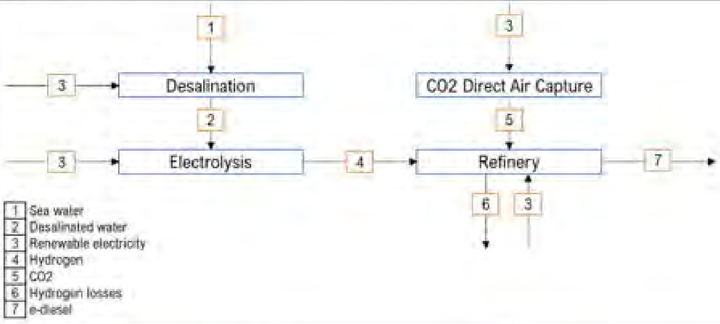
<tr><td>7</td><td>Renewable e-diesel</td><td>
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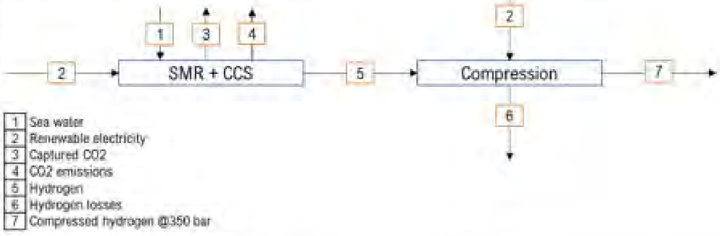
<tr><td>8</td><td>Low carbon compressed hydrogen</td><td>
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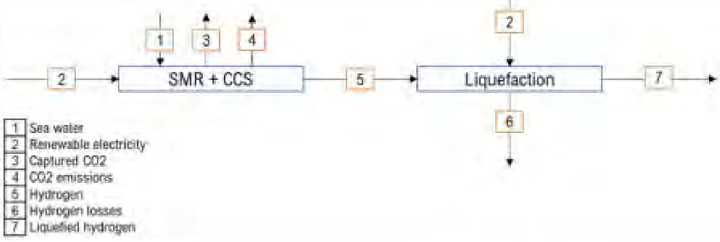
<tr><td>9</td><td>Low carbon liquified hydrogen</td><td>
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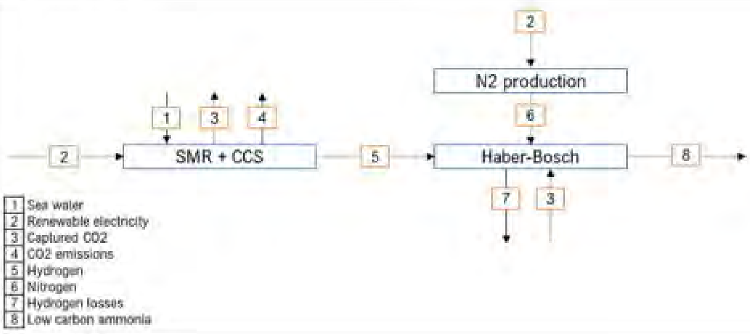
<tr><td>10</td><td>Low carbon ammonia</td><td>
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10.2 Annex 2: Assumptions for fuel production costs

Table 6. Assumptions for water desalination

Item	Value	Unit	Literature references
CAPEX	1,243	€/(m³/d)	[55]
OPEX	0.08	%/a of CAPEX	based on [55]
Lifetime	20	a	[55]
Annual full load hours	7,008	h/a	[56]
Electricity consumption per water output	3.00	kWh_e/m^3_{H2O}	[56]

Table 7. Assumptions for H2 production via water electrolysis

Item	Value	Unit	Literature references
CAPEX	400	$€/kW_{H2\ output}$	[56]
OPEX	0.03	%/a of CAPEX	[56]
Lifetime	20	a	[56]
Annual full load hours	4000	h/a	Own assumption
GHG emissions of fuel production	0	g_{CO2}/kWh_{fuel}	
Electricity consumption per hydrogen output	1.68	kWh_e/kWh_{H2}	[56]
Water consumption	0.270	kg_{H2O}/kWh_{H2}	Theoretical value

Table 8. Assumptions for H2 production via steam methane reforming

Item	Value	Unit	Literature references
CAPEX	913	$€/kW_{H2\ output}$	based on [57], p.387
OPEX	0.031	%/a of CAPEX	based on [57], p. 405
Lifetime	25	a	[58]
Annual full load hours	8000	h/a	
GHG emissions of fuel production	103.0	g_{CO2}/kWh_{fuel}	
Natural gas consumption per hydrogen output	1.365	kWh_{NG}/kWh_{H2}	[58]
CO_2 emission factor NG upstream only	45.7	g/kWh_{NG}	[59](NG pipeline for transport into the EU: 4000 km)
CO_2 emission factor NG incl. upstream	244.0	g/kWh_{NG}	[59] (NG pipeline for transport into the EU: 4000 km)
CO_2 capture rate	0.85		[58]

Table 9. Assumptions for H2 liquefaction

Item	Value	Unit	Literature references
CAPEX	1000	$€/kW_{H2}$	[60] based on [61], [62], [63]
OPEX	0.019	%/a of CAPEX	[60] based on [64]
Lifetime	30	a	[56]
Annual full load hours	7008	h/a	[56]
GHG emissions of fuel production	0	g_{CO2}/kWh_{fuel}	
Electricity consumption	0.225	kWh_e/kWh_{H2}	[56]
Hydrogen input per LH2 output	1.0541	kWh/kWh_{fuel}	[61]

Table 10. Assumptions for H2 compression

Item	Value	Unit	Literature references
CAPEX	250	$€/kW_{H2}$	based on [65]
OPEX	0.04	%/a of CAPEX	[65]
Lifetime	20	a	
Annual full load hours	4000	h/a	
GHG emissions of fuel production	0	g_{CO2}/kWh_{fuel}	
Electricity consumption	0.11	kWh_e/kWh_{H2}	LBST calculation based on [65]
Hydrogen input per CGH2 output	1.005	kWh/kWh_{fuel}	[66]

Table 11. Assumptions for LOHC production

Item	Value	Unit	Literature references
CAPEX	500	€/kW	[76]
OPEX	0.015	%/a of CAPEX	[76]
Lifetime	30	a	[76]
Annual full load hours	4000	h/a	Equal to electrolyser
GHG emissions of fuel production	0	g_{CO2eq}/kWh_{fuel}	
Electricity consumption	0.03	kWh_e/kWh_{fuel}	[76]
Hydrogen input per LOHC output	1.01	kWh/kWh_{fuel}	[76]

Table 12. Assumptions for e-LNG production

Item	Value	Unit	Literature references
Methanation			
CAPEX	1100	$€/kW_{CH4}$	[69] based on [77], [78], [79], [80], [71], [72]
OPEX	0.024	%/a of CAPEX	[69] based on [81], [77], [78], [79], [80], [71], [72]
Lifetime	20	a	
Annual full load hours	4000	h/a	
Electricity consumption	0.25	kWh_e/kWh_{fuel}	[69] based on [78]
Hydrogen input per CH_4 output	1.21	kWh/kWh_{fuel}	Based on chemical reaction
NG liquefaction			
CAPEX	300	$€/kW_{CH4}$	[82]
OPEX	0.04	%/a of CAPEX	[83]
Lifetime	30	a	Own assumption
Annual full load hours	4000	h/a	Own assumption
Electricity consumption	0.025	kWh_e/kWh_{fuel}	[84]

Table 13. Assumptions for e-ammonia production

Item	Value	Unit	Literature references
N2 production			
CAPEX	53.6	€/(kg/d)	[85]
OPEX	0.04	%/a of CAPEX	[65]
Lifetime	20	a	Own assumption
Annual full load hours	4000	h/a	Own assumption
Electricity consumption	0.108	kWh_e/kg_{N2}	based on [85]
Haber-Bosch			
CAPEX	762	$€/kW_{NH3}$	based on [85]
OPEX	0.04	%/a of CAPEX	[65]
Lifetime	20	a	Own assumption
Annual full load hours	4000	h/a	Own assumption
Electricity consumption	0.0786	kWh_e/kWh_{fuel}	LBST calculation
Hydrogen input per fuel output	1.146	kWh/kWh_{fuel}	Theoretical values
Nitrogen input per fuel output	0.16	kg/kWh_{fuel}	Theoretical values

Table 14. Assumptions for e-methanol production

Item	Value	Unit	Literature references
CAPEX	1800	$€/kW_{MeOH}$	[69] based on [86], [78], [79], [80], [71] [72], [87]
OPEX	0.023	%/a of CAPEX	[69] based on [81], [86], [78], [79], [80], [71], [72], [87]
Lifetime	20	a	Own assumption
Annual full load hours	4000	h/a	Own assumption
Electricity consumption	0.578	kWh_e/kWh_{fuel}	[69] based [86], [78], [79], [80]
Hydrogen input per fuel output	1.2283	kWh/kWh_{fuel}	[86]

Table 15. Assumptions for e-diesel production

Item	Value	Unit	Literature references
CAPEX	3000	€/kW	[69] based on [79], [80], [88], [89], [71], [72]
OPEX	1.8%	%/a of CAPEX	[69] based on [81], [79], [80], [88], [89], [71], [72]
Lifetime	20	a	Own assumption
Annual full load hours	4000	h/a	Own assumption
Electricity consumption	0.49	kWh_e/kWh_{fuel}	[69] based on [89], [78], [80]
Hydrogen input per fuel output	1.4972	kWh/kWh_{fuel}	[89]

10.3 Annex 3: Fuel logistics costs

Table 16. Assumptions for fuel logistics costs calculation

Category	Item	Value	Unit	Literature references
Trucks	Lifetime	12	years	[33]
	Truck CAPEX	165	kEUR	[33]
	Truck Annual OPEX	12	% CAPEX	[33]
	Driver cost	20.6	EUR/h	[33]
	Speed	50	km/h	[33]
	Effective working hours	2000	h/year	own calculation based on [33]
Trailers	CAPEX - CH_2 trailer	581	kEUR	[33]
	Net capacity - CH_2 trailer	670	kgH2	[33]
	CAPEX - LH_2 trailer	894	kEUR	[33]
	Net capacity - LH_2 trailer	4300	kgH2	[33]
	LH2 trailer boiloff rate	0.3	%/day	[56]
	CAPEX - LNG	235	kEUR	[57]
	Capacity - LNG	44	m3	own assumption
	LNG trailer boiloff rate	0.3	%/day	own assumption
	CAPEX - LOHC, MeOH, MGO	152	kEUR	[33]
	CAPEX - NH3	197	kEUR	[33]
	Capacity	55	m3	standard volume
	Annual OPEX - trailer	2	% CAPEX	[33]
CH2 pipeline – transmission pipeline	Lifetime	40	years	[33]
	Design throughput (large)	1,952	ktH2/y	[55]
	CAPEX	2.75	mEUR/km	[55]
	Utilization	5.000	h	[55]
	Annual OPEX	5	% CAPEX	[54]
CH2 pipeline – medium diameter	Lifetime	40	years	[33]
	Design throughput (large)	340	ktH2/y	[33]
	CAPEX	1.08	mEUR/km	[33]
	Utilization	0.75		[33]
	Annual OPEX	5	% CAPEX	[54]
	Mass losses	0.5	%	[58]
CH2 pipeline – Small diameter	Design throughput (small)	38	ktH2/y	[33]
	CAPEX	0.45	mEUR/km	[33]
	Annual OPEX	5	% CAPEX	[54]
	Mass losses	0.5	%	[58]
NG pipeline	Natural gas network costs in EU	0.00649	EUR/kWh	Eurostat
NH3 pipeline - transmission	Lifetime	40	years	[33]
	Design throughput (large)	1932	kt/y	[33]
	CAPEX	0.49	mEUR/km	[33]
	Utilization	0.75		[33]
	Annual OPEX	5	% CAPEX	own assumption
	Mass losses	0.5	%	own assumption
NH3 pipeline - distribution	Design throughput (large)	216	kt/y	[33]
	CAPEX	0.22	mEUR/km	[33]
	Annual OPEX	5	% CAPEX	own assumption
	Mass losses	0.5	%	own assumption
Other pipeline - transmission	Lifetime	40	years	[33]
	Design throughput (large)	12810	kt/y	[33]
	CAPEX	1.08	mEUR/km	[33]
	Utilization	0.75		[33]
	Annual OPEX	5	% CAPEX	own assumption
	Mass losses	0.5	%	own assumption
Other pipeline - distribution	Design throughput (large)	608	kt/y	[33]
	CAPEX	0.45	mEUR/km	[33]
	Annual OPEX	5	% CAPEX	own assumption
	Mass losses	0.5	%	own assumption
Storage	Capacity	5	days of storage	own assumption based on [54]
	Lifetime	40	years	own assumption
	CH2 CAPEX	9	EUR/kWhH2	[33]
	LH2 CAPEX	80.6	EUR/kgH2	[33]
	LNG CAPEX	4.6	EUR/kgLNG	[57]
Category	Item	Value	Unit	Literature references
	NH3 CAPEX	1.5	EUR/kgNH3	[33]
	Others CAPEX	0.5	EUR/kgfuel	[33]
	OPEX	2	% CAPEX	own assumption

10.4 Annex 4: Fuel onboard storage costs

Table 17. Assumptions for fuel onboard storage

Category	Item	Value	Unit	Literature references	Comments
LH_2	CAPEX	x	€/kWh	[90], [91], [92]	*f(y) = 13,974*storage(kg)^-0,206 + 100% markup for fuel handling system similar to LNG (crypumps, vaporizers, BOG handling system)*
	OPEX	0.0%	%/a of CAPEX		
	Lifetime	30	a		
	Fuel energy density by volume	2.359	kWh/l		
	Fuel energy density by weight	33.333	kWh/kg		
	Fuel density	0.071	kg/l		
	Tank: volumetric storage density	1.75	kWh/l	[69]	*Cylinder: approx. 30 m outer length, 6 m outer diameter; filling level: 90%; superinsulation*
	Tank (rectangular room): volumetric storage density	0.976	kWh/l	[69]	*Module of several cylinders*
	Tank: specific weight	x	kg/m3	[92]	*f(y) = 976 x volume ^-0,164 [kg/m3]*
CH2	CAPEX	9	€/kWh	[33]	
	OPEX	0.0%	%/a of CAPEX		
	Lifetime	30	a		
	Fuel energy density by volume	0.81	kWh/l		
	Fuel energy density by weight	33.333	kWh/kg		
	Fuel density	0.024	kg/l		
	Tank: volumetric storage density	0.66	kWh/l	[69]	*Cylinder: approx. 10,975 m outer length, 0.59 m outer diameter*
	Tank (rectangular room): volumetric storage density	0.34	kWh/l	[69]	*Module of several cylinders inside a container frame*
	Tank: specific weight	433	kg/m3	[92]	
LOHC	CAPEX	3.00	$€/kg_{tank}$		*same as standard marine fuel tank*
	OPEX	0.0%	%/a of CAPEX		
	Lifetime	30	a		
	Fuel energy density by volume	1.32	kWh/l	[76]	*LOHC unloaded: C21H20; loaded C21H38*
	Fuel energy density by weight	1.45	kWh/kg	[76]	
	Fuel density (H_2 loaded)	0.91	kg/l	[76]	*H2 content: 0.06245 kgH2/kgLOHC, loaded*
	Tank: volumetric storage density	1.14	kWh/l	[69]	*10 chambers (9 chambers for loaded LOHC at start of trip, one chamber empty; all chambers used for loaded and unloaded LOHC separately); assumption (4% space losses for piping etc.)*
	Tank (rectangular room): volumetric storage density	1.03	kWh/l	[69]	*Assumption*
	Tank: specific weight	47	kg/m3	[76] Engineeringtoolbox.com	*same as standard marine fuel tank*
LNG	CAPEX	x	€/kWh	[47] + own market analysis	*3385 EUR/m3 (tanks + fuel handling system)*
	OPEX	0.0%	%/a of CAPEX		
	Lifetime	30	a		
	Fuel energy density by volume	5.925	kWh/l		
	Fuel energy density by weight	13.5	kWh/kg	Engineeringtoolbox.com	
	Fuel density	0.44	kg/l		*@ 100 K; 0.1 MPa; https://www.engineeringtoolbox.com/methane-density-specific-weight-temperature-pressure-d_2020.html*
	Tank: volumetric storage density	4.525	kWh/l	[69]	*Same ratio as for LH2*
	Tank (rectangular room): volumetric storage density	2.524	kWh/l	[69]	*Same ratio as for LH2*
	Tank: specific weight	x	kg/m3	own market research	*weight = 1192*Volume^(-0,303)*
Ammonia	CAPEX	3.00	$€/kg_{tank}$		*Same as MGO per kg of tank mass*
	OPEX	0.0%	%/a of CAPEX		
	Lifetime	30	a		
	Fuel energy density by volume	3.532	kWh/l		*Density liquid (-33.3°C (239.85 K): 681.9 kg/m³; gaseous at STP (Standard Temperature and Pressure - 0°C (273.15 K) and 1 atm (101.325 kPa)): 0.769 kg/m3*
	Fuel energy density by weight	5.18	kWh/kg		
	Fuel density	0.6819	kg/l		
	Tank: volumetric storage density	2.891	kWh/l	[69]	*Assumption: cryogenic storage (-33°C @ 1 bar); similar to LH2 cylinder, but thinner insulation*
	Tank (rectangular room): volumetric storage density	1.613	kWh/l	[69]	
	Tank: specific weight	x	kg/m3	[own research]	*weight = 559,49*Volume^ (-0,207)*
Methanol	CAPEX	3.00	$€/kg_{tank}$		*Same as MGO per kg of tank mass*
	OPEX	0.0%	%/a of CAPEX		
	Lifetime	30	a		
	Fuel energy density by volume	4.44	kWh/l		
	Fuel energy density by weight	5.47	kWh/kg		
	Fuel density	1.232	kg/l		
	Tank: volumetric storage density	4.00	kWh/l	[69]	*Assumption*
	Tank (rectangular room): volumetric storage density	3.60	kWh/l	[69]	*Assumption*
	Tank: specific weight	x	kg/m3	Engineeringtoolbox.com	*Assumption - same as for fuel oil (374,27*volume$^{-0,226}$)*
MGO	CAPEX	3.00	$€/kg_{tank}$		*[CRIST 2019]*
	OPEX	0.0%	%/a of CAPEX		
	Lifetime	30	a		
	Fuel energy density by volume	9.97	kWh/l		*based on lower heating value (HI)*
	Fuel energy density by weight	11.9	kWh/kg		*based on lower heating value (HI)*
	Fuel density	0.838	kg/l		
	Tank: volumetric storage density	8.973	kWh/l	[69]	*Assumption*
	Tank (rectangular room): volumetric storage density	8.0757	kWh/l	[69]	*Assumption*
	Tank: specific weight	x	kg/m3	Engineeringtoolbox.com	*(374,27*volume$^{-0,226}$)*

10.5 Annex 5: Onboard reforming costs

Table 18. Assumptions for onboard fuel reforming

Category	Item	Value	Unit	Reference	Comments
LOHC dehydrogenation & cleaning	CAPEX (per kW output)	1100	€/kW	[93]	
	OPEX	0,03	%/a of CAPEX	[93]	
	Lifetime	20	a	[93]	
	GHG emissions per hydrogen output		kg_{CO2}/kWh_{H2}		
	LOHC input per hydrogen output - LT FC	1,49	kWh/kWh_{H2}	[93]	*Without heat integration*
	LOHC input per hydrogen output - ICE	1,25	kWh/kWh_{H2}	[93]	*With engine heat integration*
	LOHC input per hydrogen output - HT FC	1,05	kWh/kWh_{H2}	[93]	*With FC heat integration*
	PM emissions	0,000	g/kWh_{H2}		*Heated with H2 which has hydrocarbon content except traces of HC from side reactions*
	NOx emissions	0,005	g/kWh_{H2}	[94], [95], [96]	*From hydrogen combustion for heat supply; NOx [95] [96] Heat input [94],*
	SOx emissions	0,000	g/kWh_{H2}		*Heated with tail gas without sulphur*
	NMVOC emissions	0,000	g/kWh_{H2}		*Heated with H2 which has hydrocarbon content except traces of HC from side reactions*
	CO emissions	0,000	g/kWh_{H2}		*Heated with H2 which has hydrocarbon content except traces of HC from side reactions*
	LOHC reformer specific weight	17,000	kg/kW_{output}	[93]	
	LOHC reformer specific volume	0,100	m^3/kW_{H2}	[93]	
LNG reformer	CAPEX (per kW output)	935,9	€/kW	[97]	*exchange rate GBP EUR: 1.10*
	OPEX	0,02	%/a of CAPEX	assumption	
	Lifetime	20	a	assumption	
	GHG emissions per hydrogen output		kg_{CO2}/kWh_{H2}		
	LNG input per hydrogen output	1,44	kWh/kWh_{H2}	[97] + [98]	*79.5% related to the HHV => 1.1/1.182*79.5% = 74.0% related to the LHV*
	PM emissions	0,000	g/kWh_{H2}	[99]	*Derived from PAFC with steam reformer*
	NOx emissions	0,005	g/kWh_{H2}	[99]	*Derived from PAFC with steam reformer (0.9 mg per MJ of NG input)*
	SOx emissions	0,000	g/kWh_{H2}	[99]	*Derived from PAFC with steam reformer*
	NMVOC emissions	0,002	g/kWh_{H2}	[99]	*Derived from PAFC with steam reformer (0.3 mg per MJ of NG input)*
	CO emissions	0,009	g/kWh_{H2}	[99]	*Derived from PAFC with steam reformer (1.7 mg per MJ of NG input)*
	LNG reformer specific weight	27,3	kg/kW_{output}	[98]	
	LNG reformer specific volume	0,16	m^3/kW_{H2}	[98]	
Ammonia cracker	CAPEX (per kW output)	423,5	€/kW	[97], [100]	*exchange rate GBP EUR: 1.10 cracker + evaporator (@110 EUR/kW$_{NH3}$)*
	OPEX	0,02	%/a of CAPEX	assumption	
	Lifetime	20	a	assumption	
	GHG emissions per hydrogen output		kg_{CO2}/kWh_{H2}		
	NH_3 input per hydrogen output	1,329	kWh/kWh_{H2}	[101]	*Calculation base on inputs and outputs indicated in [101]*
	PM emissions	0,000	g/kWh_{H2}		*Heated with tail gas without hydrocarbons*
	NOx emissions	0,004	g/kWh_{H2}	[99]	*Derived from PAFC with steam reformer (0.9 mg per MJ of NG input)*
	SOx emissions	0,000	g/kWh_{H2}		*Heated with tail gas without sulphur*
	NMVOC emissions	0,000	g/kWh_{H2}		*Heated with tail gas without hydrocarbons*
	CO emissions	0,000	g/kWh_{H2}		*Heated with tail gas without hydrocarbons*
	NH_3 cracker specific weight	11,2	kg/kW_{output}	[102]	
	NH_3 cracker specific volume	0,05	m^3/kW_{H2}	[102]	
Methanol reformer	CAPEX (per kW output)	936	$€/kW_{H2}$		*Assumption: equal to LNG reformer*
	OPEX	0,02	%/a of CAPEX		
	Lifetime	20	a		
	GHG emissions per hydrogen output		kg_{CO2}/kWh_{H2}		
	MeOH input per hydrogen output	1,2500	kWh/kWh_{H2}	[103]	*Onboard methanol reformer for low temperature PEMFC*
	PM emissions	0,0000	g/kWh_{H2}	[99]	*Derived from PAFC with steam reformer*
	NOx emissions	0,0001	g/kWh_{H2}	[104]	*Catalytic burner, traced back to H2 output*
	SOx emissions	0,0000	g/kWh_{H2}		*No sulphur in the fuel*
	NMVOC emissions	0,0060	g/kWh_{H2}	[104]	*Catalytic burner, traced back to H2 output*
	CO emissions	0,0057	g/kWh_{H2}	[104]	*Catalytic burner, traced back to H2 output*
	MeOH reformer specific weight	16,8	kg/kW_{output}	own estimation based on [105] and [106]	
	MeOH reformer specific volume	0,03	m^3/kW_{H2}	own estimation based on [105] and [106]	

10.6 Annex 6: Fuel cells and engines

Table 19. Assumptions for fuel cells and engines

Category	Item	Value	Unit	Literature references	*Comments*
PEM	CAPEX	250	€/kW	[107], [108]	
	OPEX	2%	%/a of CAPEX	[107], [109]	
	Lifetime	20	a	[107]	
	Efficiency	56%	%	[107], [110]	
	PM emissions	0	g/kWh_e		
	NOx emissions	0	g/kWh_e		
	SOx emissions	0	g/kWh_e		
	NMVOC emissions	0	g/kWh_e		
	CO emissions	0	g/kWh_e		
SOFC-H2	CAPEX	500	€/kW	[107], [109]	*SOFC using H2*
	OPEX	2%	%/a of CAPEX	[107], [109]	
	Lifetime	20	a	[107]	
	Efficiency	50%	%	[107], [111]	
	PM emissions	0	g/kWh_e		
	NOx emissions	0	g/kWh_e		
	SOx emissions	0	g/kWh_e		
	NMVOC emissions	0	g/kWh_e		
	CO emissions	0	g/kWh_e		
SOFC-ir	CAPEX	500	€/kW	[107], [109]	*SOFC with internal reforming (MeOH, LNG, NH3)*
	OPEX	2%	%/a of CAPEX	[107], [109]	
	Lifetime	20	a	[107]	
	Efficiency	60%	%	[111]	
	PM emissions	0	g/kWh_e		*Air pollutant emissions for NG SOFC with internal reforming (assumption: same emissions as for NG MCFC); Methanol SOFC probably similar, no NMVOC and CO in case of NH3, maybe NH3 slip and different NOx in case of NH3*
	NOx emissions	0.0017	g/kWh_e	[112]	
	SOx emissions	0	g/kWh_e		*No SOx because no sulphur in the fuel*
	NMVOC emissions	0.0008	g/kWh_e	[112]	
	CO emissions	0.0017	g/kWh_e	[112]	
ICE-H2	CAPEX	425	€/kW	assumptions: equal to LNG	*ICE running on hydrogen*
	OPEX	1%	%/a of CAPEX	assumption: equal to LNG	
	Lifetime	20	a	assumption	
	GHG emissions per mechanical output		g_{CO2}/kWh_{mech}		*see calculation in "Calculation engine"*
	Efficiency	45%	%	assumption: equal to MGO	
	PM emissions	0	g/kWh_{mech}		
	NOx emissions	2.6	g/kWh_{mech}	[113]	*Assumption: H2-ICE equal to LNG-ICE; IMO Tier III: 1 January 2016 and operating in the North American ECA and the United States Caribbean Sea ECA, 1 January 2021 and operating in the Baltic Sea ECA or the North Sea ECA; engines with n < 130 rounds/min*
	SOx emissions	0	g/kWh_{mech}		
	NMVOC emissions	0	g/kWh_{mech}		
	CO emissions	0	g/kWh_{mech}		
ICE-LNG	CAPEX	425	€/kW	[57]	*ICE running on methane incl. SCR*
	OPEX	1%	%/a of CAPEX	[114]	
	Lifetime	20	a		
	GHG emissions per mechanical output		g_{CO2}/kWh_{mech}		*see calculation in "Calculation engine"*
	Efficiency	50%	%	[115]	
	S content pilot diesel fuel	0.001			
	Share pilot diesel fuel	0.06		[116]	
	PM emissions	0.1	g/kWh_{mech}	[116]	*Air pollutant emissions (2-stroke, dual fuel)*
	NOx emissions	2.6	g/kWh_{mech}	[T&E 2016], [116], [113]	*IMO Tier III: 1 January 2016 and operating in the North American ECA and the United States Caribbean Sea ECA, 1 January 2021 and operating in the Baltic Sea ECA or the North Sea ECA; engines with n < 130 rounds/min*
	SOx emissions	0.020	g/kWh_{mech}	[116]	*No sulphur in the (main) fuel, but sulphur in pilot diesel fuel*
	NMVOC emissions	0.1	g/kWh_{mech}	[116]	*Assumption: 80% fo VOC consists of CH4*
	CO emissions	0.3	g/kWh_{mech}	[116]	
ICE-NH3	CAPEX	425	€/kW	assumptions: equal to LNG	*ICE running on ammonia*
	OPEX	1%	%/a of CAPEX	assumptions: equal to LNG	
	Lifetime	20	a	assumptions	
	GHG emissions per mechanical output		g_{CO2}/kWh_{mech}		*see calculation in "Calculation engine"*
	Efficiency	50%	%	[115]	
	S content pilot diesel fuel	0.001			
	Share pilot diesel fuel	0.06			
	PM emissions	0	g/kWh_{mech}		*Air pollutant emissions (2-stroke, dual fuel)*
	NOx emissions	3.4	g/kWh_{mech}	[113]	*IMO Tier III: 1 January 2016 and operating in the North American ECA and the United States Caribbean*

Category	Item	Value	Unit	Literature references	*Comments*
	SOx emissions	0.0200	g/kWh$_{mech}$	[116]	*No sulphur in the (main) fuel, but sulphur in pilot diesel fuel*
	NMVOC emissions	0	g/kWh$_{mech}$		
	CO emissions	0	g/kWh$_{mech}$		
ICE-MeOH	CAPEX	425	€/kW	assumptions: equal to LNG	*ICE running on methanol*
	OPEX	1%	%/a of CAPEX	assumptions: equal to LNG	
	Lifetime	20	a		
	GHG emissions per mechanical output		g$_{CO2}$/kWh$_{mech}$		*see calculation in "Calculation engine"*
	Efficiency	45%	%	assumptions: equal to MGO	
	S content pilot diesel fuel	0.001			
	Share pilot diesel fuel	0.06			
	PM emissions	0.01	g/kWh$_{mech}$	[114]	*Air pollutant emissions (2-stroke, dual fuel)*
	NOx emissions	3.4	g/kWh$_{mech}$	[114] [113]	*IMO Tier III: 1 January 2016 and operating in the North American ECA and the United States Caribbean Sea ECA, 1 January 2021 and operating in the Baltic Sea ECA or the North Sea ECA; engines with n < 130 rounds/min*
	SOx emissions	0.022	g/kWh$_{mech}$		*No sulphur in the (main) fuel, but sulphur in pilot diesel fuel*
	NMVOC emissions	0.5	g/kWh$_{mech}$	assumption: equal to diesel (VOC has low CH4 content)	
	CO emissions	0.3	g/kWh$_{mech}$	assumption: equal to LNG	
ICE-MGO	CAPEX	244	€/kW	[57]	*ICE running on MGO*
	OPEX	1%	%/a of CAPEX	assumption	
	Lifetime	20	a	assumption	
	GHG emissions per mechanical output		g$_{CO2}$/kWh$_{mech}$		*see calculation in "Calculation engine"*
	Efficiency	45%	%	[115]	
	S content	0.001		[113]	*IMO: Sulphur content of fuel in SECA areas: max. 0.1% S or SO2 scrubbers required*
	PM emissions	0.269	g/kWh$_{mech}$	[116]	*Air pollutant emissions (2-stroke); PM emissions partly depend on the S content of the fuel (see equation)*
	NOx emissions	3.400	g/kWh$_{mech}$	[116] [113]	*Similar to diesel according to: [de Vries 2019]*
	SOx emissions	0.371	g/kWh$_{mech}$	[116]	*IMO: Sulphur content of fuel in SECA areas: max. 0.1% S; sulphur content of PtL is 0!*
	NMVOC emissions	0.500	g/kWh$_{mech}$	[116]	*VOC mainly consists of NMVOC in case of diesel engines*
	CO emissions	0.350	g/kWh$_{mech}$	[116]	*2-stroke: 0.35 g/kWh; 4-stroke: 0.5 g/kWh*

Table 20. Assumptions for fuel cells and engines mass and space requirements

Category	Item	Value	Unit	Reference
Fuel cell	Mass (in kg) - slope	3.7871	x power [kW]	[117]
	Mass (in kg) - intercept	-29.147		[117]
	Calculated mass of the FC system	F(x)	kg	Calculated F(x) = ax + b no less than 1 tonne
	Volume (in m3) - slope	0.0067	x power [kW]	[117]
	Volume (in m3) - intercept	-0.0714		[117]
	Calculated volume of the FC system	F(x)	m3	Calculated F(x) = ax + b no less than 20m3
ICE	Mass (in kg) - slope	13.783	x power [kW]	[Wartsila, MAN product catalogues]
	Mass (in kg) - intercept	-5865.4		[Wartsila, MAN product catalogues]
	Calculated mass (in kg) of the ICE System	F(x)	kg	Calculated F(x) = ax + b no less than 1 tonne
	Volume (in m3) - slope	0.0229	x power [kW]	[Wartsila, MAN product catalogues]
	Volume (in m3) - intercept	-20.628		[Wartsila, MAN product catalogues]
	Calculated volume (in m3)) of the ICE System	F(x)	m3	Calculated F(x) = ax + b no less than 20m3

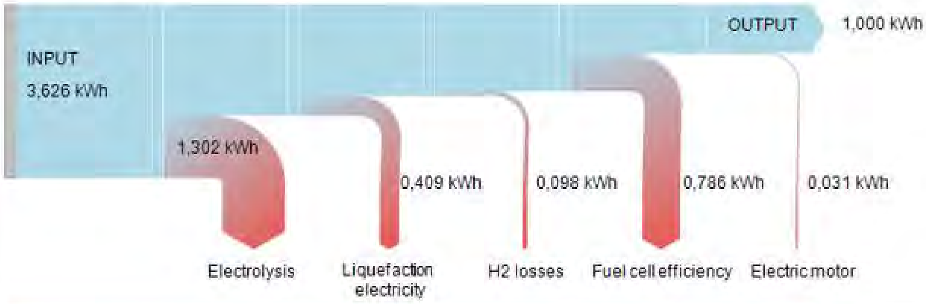
10.7 Annex 7: Ships operational profiles

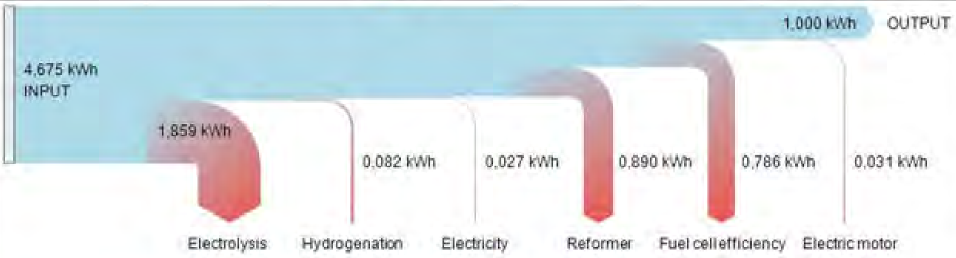
Ship Type	Size	Size unit	Number active	Avg. deadweight tonnes)	Avg. GT	Avg TEU	AE power (120% MCR) [kW]	Avg. propulsion power (kW)	Avg. design speed (knots)	Avg. days at sea	Avg. days at berth	Voyage distance [nm]	Payload value	Payload value unit	Avg.* sea speed (knots)	Average at-sea main engine load factor	Ratio of average at-sea speed to design speed	Auxiliary engine load (kW)			
																		At berth	At anchorag e	Manoeuvr ing	At sea
Bulk carrier	0–9,999	dwt	1.446	4.271	2.104		600	1.796	11,8	178	182	1152	4.014,89	US D/24h	9,4	0,52	0,80	110	180	500	190
Bulk carrier	10,000–34,999	dwt	2.014	27.303	17.301		600	5.941	13,8	177	183	2650	8.087,57	US D/24h	11,4	0,60	0,83	110	180	500	190
Bulk carrier	35,000–59999	dwt	3.391	49.487	30.582		816	8.177	14,3	184	176	6650	10.123,22	US D/24h	11,8	0,57	0,83	150	250	680	260
Bulk carrier	60,000–99,999	dwt	3.409	76.147	41.538		1.320	9.748	14,4	214	146	11500	11.911,66	US D/24h	11,9	0,54	0,83	240	400	1100	410
Bulk carrier	100,000–199,999	dwt	1.242	169.868	88.277		1.320	16.741	14,5	252	108	11500	16.125,59	US D/24h	11,7	0,50	0,81	240	400	1100	410
Bulk carrier	200,000–+	dwt	516	251.667	130.223		1.320	20.094	14,6	258	102	11500	18.705,12	US D/24h	12,2	0,56	0,84	240	400	1100	410
Chemical tanker	0–4,999	dwt	6.067	4.080	1.392		240	987	12,2	168	192	6650	9.513,31	US D/24h	9,8	0,57	0,80	110	170	190	200
Chemical tanker	5,000–9,999	dwt	862	7.276	4.854		696	3.109	12,9	185	175	6650	9.877,34	US D/24h	10,6	0,61	0,82	330	490	560	580
Chemical tanker	10,000–19,999	dwt	1.088	15.324	9.751		696	5.101	13,8	190	170	11500	10.794,00	US D/24h	11,7	0,67	0,85	330	490	560	580
Chemical tanker	20,000-39,999	dwt	706	32.492	23.223		1.080	8.107	14,7	202	158	11500	12.749,44	US D/24h	12,3	0,64	0,84	790	550	900	660
Chemical tanker	40,000–+	dwt	1.289	48.796	36.808		1.080	8.929	14,6	201	159	11500	14.606,46	US D/24h	12,3	0,65	0,84	790	550	900	660
Container	0–999	TEU	1.027	8.438	6.452	602	948	5.077	16	196	164	673	0,13	US D/TEU/nm	12,4	0,48	0,78	370	450	790	410
Container	1,000–1,999	TEU	1.271	19.051	15.019	1.409	2.100	12.083	19	210	150	1000	0,13	US D/TEU/nm	13,9	0,46	0,73	820	910	1750	900
Container	2,000–2,999	TEU	668	34.894	27.756	2.545	2.280	20.630	21,1	220	140	2650	0,13	US D/TEU/nm	15	0,39	0,71	610	910	1900	920
Container	3,000–4,999	TEU	815	52.372	42.867	4.117	3.000	34.559	23,1	246	114	6650	0,13	US D/TEU/nm	16,1	0,33	0,70	1100	1350	2500	1400
Container	5,000–7,999	TEU	561	74.661	68.337	6.033	3.360	52.566	24,6	258	102	11500	0,13	US D/TEU/nm	16,3	0,34	0,66	1100	1400	2800	1450
Container	8,000–11,999	TEU	623	110.782	100.228	9.258	3.480	57.901	23,9	261	99	11500	0,13	US D/TEU/nm	16,3	0,40	0,68	1150	1600	2900	1800
Container	12,000–14,500	TEU	227	149.023	145.455	13.562	3.900	61.231	23,8	246	114	11500	0,13	US D/TEU/nm	16,1	0,41	0,68	1300	1800	3250	2050
Container	14,500–19,999	TEU	101	179.871	177.304	17.410	4.320	60.202	20,2	250	110	11500	0,13	US D/TEU/nm	14,8	0,56	0,73	1400	1950	3600	2300
Container	20,000+	TEU	44	195.615	217.850	21.568	4.320	60.210	20,3	210	150	11500	0,13	US D/TEU/nm	15	0,51	0,74	1400	1950	3600	2300
General cargo	0–4,999	dwt	13.296	2.104	1.206		216	1.454	11,1	170	190	300	3.073,25	US D/24h	8,7	0,53	0,78	90	50	180	60
General cargo	5,000–9,999	dwt	2.245	6.985	4.894		588	3.150	12,7	176	184	673	4.834,16	US D/24h	10,1	0,55	0,80	240	130	490	180
General cargo	10,000–19,999	dwt	1.054	13.423	9.444		1.740	5.280	14	192	168	1000	6.186,03	US D/24h	12	0,69	0,86	720	370	1450	520
General cargo	19,999+	dwt	793	36.980	22.424		1.740	9.189	15	197	163	1000	9.068,93	US D/24h	13	0,71	0,87	720	370	1450	520
Oil tanker	0–4,999	dwt	9.692	3.158	1.181		450	966	11,4	135	225	1784	6.646,46	US D/24h	8,7	0,46	0,76	250	250	375	250
Oil tanker	5,000–9,999	dwt	779	6.789	4.570		672	2.761	12,1	142	218	2650	7.662,00	US D/24h	9,1	0,49	0,75	375	375	560	375
Oil tanker	10,000–19,999	dwt	235	14.733	9.985		828	4.417	12,9	136	224	2650	9.185,00	US D/24h	9,6	0,54	0,74	690	500	580	490
Oil tanker	20,000–59,999	dwt	615	43.750	27.500		864	8.975	14,6	166	194	6650	14.000,00	US D/24h	11,7	0,51	0,80	720	520	600	510
Oil tanker	60,000–79,999	dwt	429	72.826	41.863		924	11.837	14,8	194	166	6650	16.000,00	US D/24h	12,2	0,53	0,82	620	490	770	560
Oil tanker	80,000–119,999	dwt	1.029	109.262	60.338		1.092	13.319	14,8	195	165	11500	22.500,00	US D/24h	11,6	0,48	0,78	800	640	910	690
Oil tanker	120,000–199,999	dwt	597	155.878	82.393		3.000	17.446	15,1	220	140	11500	26.000,00	US D/24h	11,7	0,48	0,77	2500	770	1300	860
Oil tanker	200,000–+	dwt	755	307.866	160.060		3.000	27.159	15,5	252	108	11500	38.000,00	US D/24h	12,5	0,48	0,81	2500	770	1300	860

Ship Type	Size	Size unit	Number active	Avg. deadweight tonnes)	Avg. GT	Avg TEU	AE power (120% MCR) [kW]	Avg. propulsion power (kW)	Avg. design speed (knots)	Avg. days at sea	Avg. days at berth	Voyage distance [nm]	Payload value	Payload value unit	Avg.* sea speed (knots)	Average at-sea main engine load factor	Ratio of average at-sea speed to design speed	Auxiliary engine load (kW)			
																		At berth	At anchorag e	Manoeuvr ing	At sea
Ferry-pax only	0-299	GT	10.680	65	185		228	1.152	19,3	162	198	100	358,61	US D/24h	15,44	0,56	0,80	190	190	190	190
Ferry-pax only	300-999	GT	666	102	543		228	3.182	26,2	161	199	100	1.052,57	US D/24h	20,96	0,56	0,80	190	190	190	190
Ferry-pax only	1,000-1,999	GT	51	354	1.421		228	2.623	14,5	135	225	100	2.754,52	US D/24h	11,6	0,56	0,80	190	190	190	190
Ferry-pax only	2000-+	GT	55	1.730	6.443		624	6.539	16,2	199	161	250	12.488,55	US D/24h	12,96	0,56	0,80	520	520	520	520
Cruise	0–1,999	GT	812	241	906		696	911	12,7	93	267	100	1.755,34	US D/24h	8,8	0,38	0,69	450	450	580	450
Cruise	2,000–9,999	GT	110	867	5.008		696	3.232	13,8	148	212	200	9.706,80	US D/24h	9,9	0,42	0,72	450	450	580	450
Cruise	10,000–59,999	GT	105	4.018	31.105		6.600	19.378	19	206	154	1000	60.295,33	US D/24h	13,8	0,43	0,73	3500	3500	5500	3500
Cruise	60,000–99,999	GT	98	8.249	79.947		17.880	51.518	21,8	256	104	4000	154.971,88	US D/24h	15,7	0,42	0,72	11500	11500	14900	11500
Cruise	100,000–149,999	GT	61	10.935	123.801		17.880	67.456	21,3	250	110	4000	239.980,80	US D/24h	16,4	0,50	0,77	11500	11500	14900	11500
Cruise	150,000+	GT	21	13.499	174.893		17.880	73.442	22	236	124	4000	339.019,57	US D/24h	16,93897	0,50	0,77	11500	11500	14900	11500
Ferry – ro-pax	0–1,999	GT	2.854	309	669	13	126	1.383	13	165	195	100	3,00	US D/TEU/nm	8,4	0,70	0,80	105	105	105	105
Ferry – ro-pax	2,000-4,999	GT	400	832	3.053	19	396	5.668	17,4	167	193	150	3,00	US D/TEU/nm	13,9	0,70	0,80	330	330	330	330
Ferry – ro-pax	5,000-9,999	GT	227	1.891	7.171	43	804	12.024	21,6	155	205	150	3,00	US D/TEU/nm	17,28	0,56	0,80	670	670	670	670
Ferry – ro-pax	10,000-19,999	GT	231	3.952	14.123	84	1.320	15.780	20,3	190	170	150	3,00	US D/TEU/nm	16,24	0,56	0,80	1100	1100	1100	1100
Ferry – ro-pax	20,000-+	GT	282	6.364	31.985	168	2.340	28.255	22,6	219	141	150	3,00	US D/TEU/nm	18,08	0,56	0,80	1950	1950	1950	1950
Refrigerated bulk	0–1,999	dwt	1.371	2.409	651		684	793	12,1	147	213	673	3.234,39	US D/24h	13,4	0,56	0,80	520	570	560	570
Refrigerated bulk	2,000-5,999	dwt	213	3.986	3.388		1.440	3.223	14,7	149	211	1000	3.911,57	US D/24h	11,76	0,56	0,80	1100	1200	1150	1200
Refrigerated bulk	6,000-9,999	dwt	182	7.476	7.151		1.980	6.206	17,4	150	210	2650	4.959,74	US D/24h	13,92	0,56	0,80	1500	1650	1600	1650
Refrigerated bulk	0,000-+	dwt	157	12.612	11.727		3.720	11.505	20,2	218	142	6650	6.042,19	US D/24h	16,16	0,56	0,80	2850	3100	3000	3100
Ro-ro	0–4,999	dwt	2.174	1.406	3.847	63	1.560	1.618	11,2	129	231	100	3,00	US D/TEU/nm	8,8	0,53	0,79	750	430	1300	430
Ro-ro	5,000-9,999	dwt	202	6.955	11.524	125	2.520	9.909	17,6	201	159	150	3,00	US D/TEU/nm	14,2	0,58	0,81	1100	680	2100	680
Ro-ro	10,000-14,999	dwt	135	12.101	25.131	254	3.240	15.939	19,6	218	142	200	3,00	US D/TEU/nm	15,68	0,56	0,80	1200	950	2700	950
Ro-ro	15,000-+	dwt	89	27.488	51.780	359	3.240	19.505	19,1	199	161	200	3,00	US D/TEU/nm	15,28	0,56	0,80	1200	950	2700	950
Vehicle	0-29,999	GT	168	5.151	20.693		1.320	7.264	17,3	213	147	11500	107.982	US D/24h	14,2	0,60	0,82	800	500	1100	500
Vehicle	30,000-49,999	GT	189	13.571	32.433		1.680	11.831	19,4	254	106	11500	155.992	US D/24h	15,5	0,56	0,80	850	550	1400	510
Vehicle	50,000-+	GT	487	20.947	46.667		1.680	14.588	19,9	281	79	11500	214.200	US D/24h	15,92	0,56	0,80	850	550	1400	510

10.8 Annex 8: Energy efficiency comparison

Table 21. Fuel production process

#	Option	Energy efficiency
1	LH2 - PEM FC	
2	LH2 - SOFC	
3	LH2 - ICE	
4	CGH2 - PEM FC	
5	CGH2 - SOFC	

#	Option	Energy efficiency
6	CGH2 - ICE	
7	LOHC - PEM FC	
8	LOHC - SOFC	
9	LOHC - ICE	
10	LNG - PEM FC	
11	LNG - SOFC	

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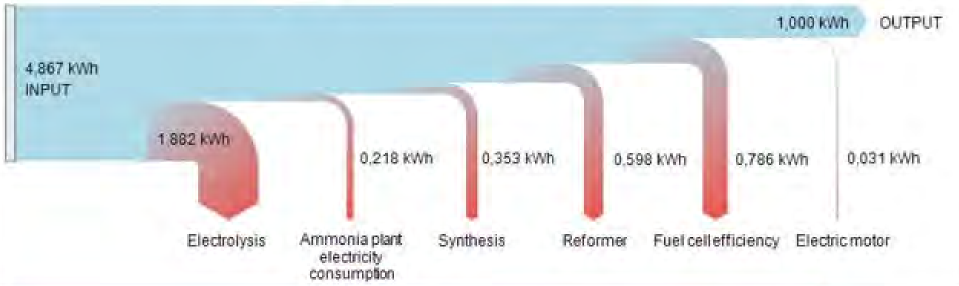
<tr><td>12</td><td>LNG - ICE</td><td>
</td></tr>
<tr><td>13</td><td>NH3 - PEM FC</td><td>
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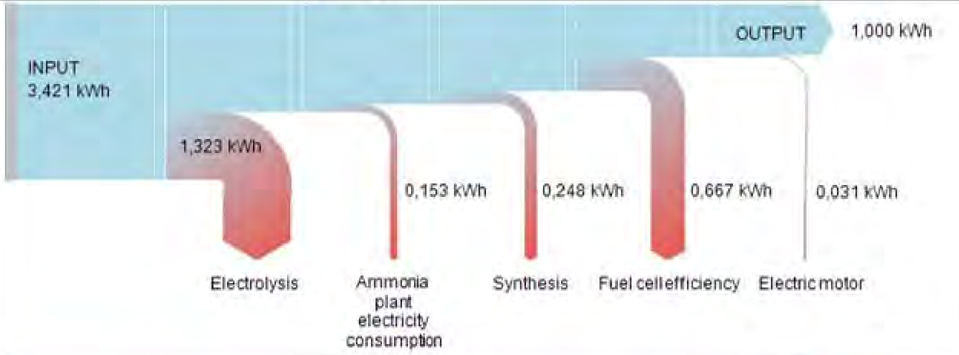
<tr><td>14</td><td>NH3 - SOFC</td><td>
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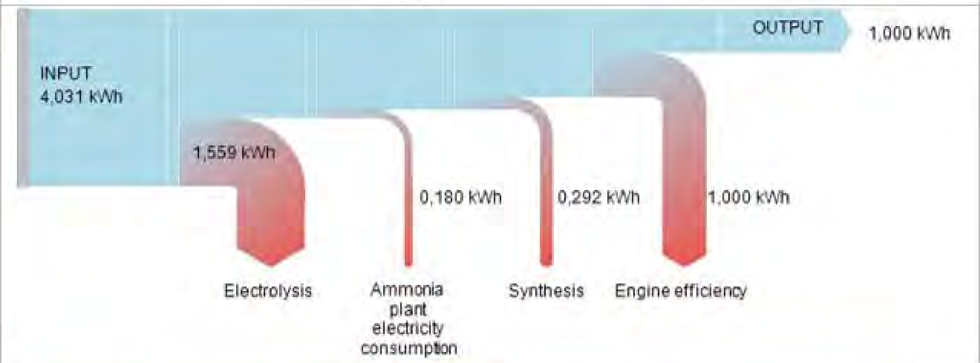
<tr><td>15</td><td>NH3 - ICE</td><td>
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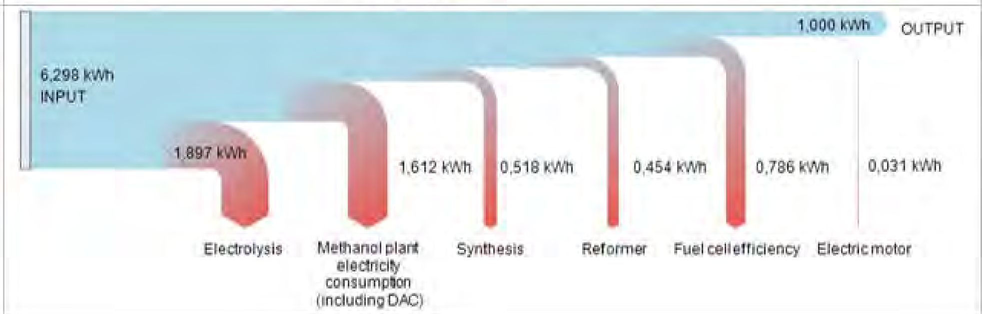
<tr><td>16</td><td>MeOH - PEM FC</td><td>
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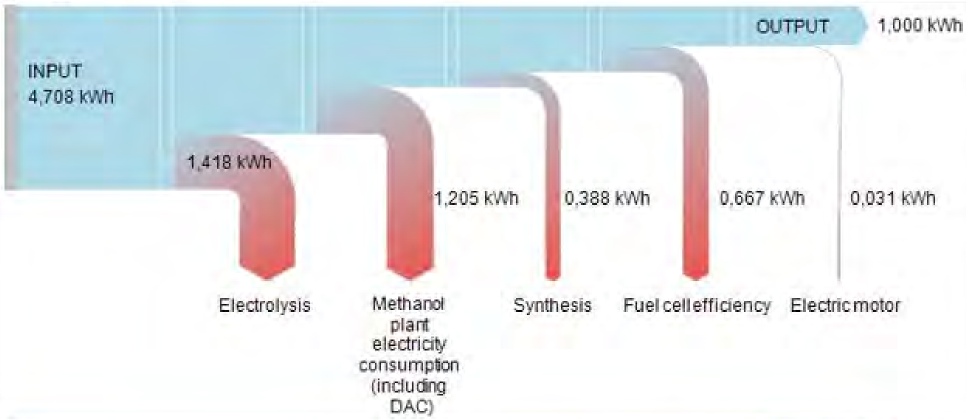
<tr><td>17</td><td>MeOH - SOFC</td><td>
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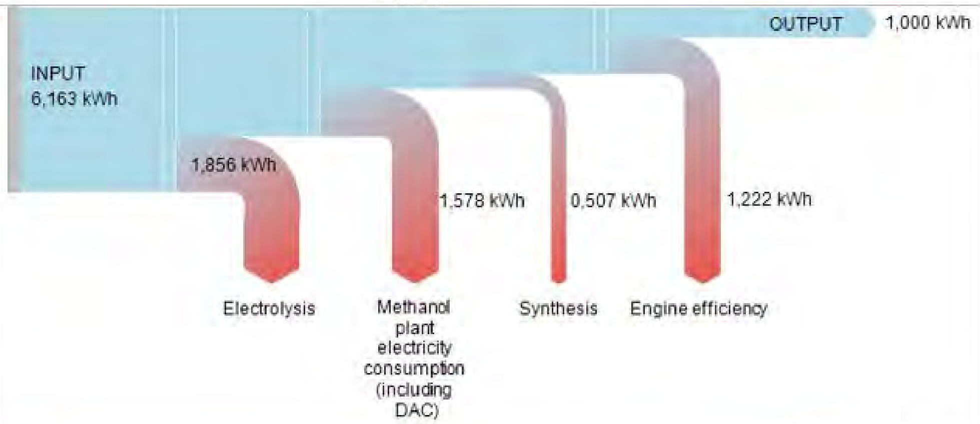
<tr><td>18</td><td>MeOH - ICE</td><td>
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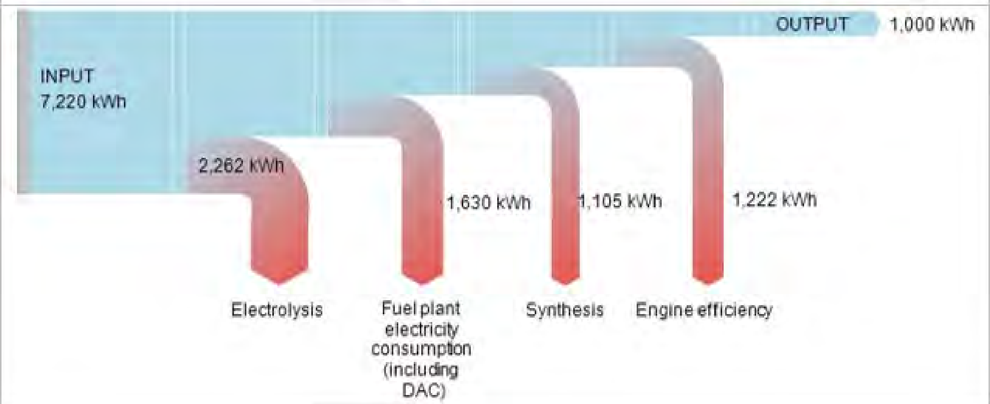
<tr><td>19</td><td>MGO - ICE</td><td>
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