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Can hydrogen storage in metal hydrides be economically competitive with compressed and liquid hydrogen storage? A techno-economical perspective for the maritime sector

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HIGHLIGHTS

- The case of refueling a small hydrogen-powered vessel is considered.
- Hydrogen storage in metal hydrides is compared with compressed and liquid hydrogen.
- The techno-economic evaluation includes hydrogen production, handling, and storage.
- Component dimensioning is based on dynamic mass flow, pressure variation modelling.
- The simplified infrastructure for refueling metal hydride tanks can reduce costs.

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ABSTRACT

The aim of this work is to evaluate if metal hydride hydrogen storage tanks are a competitive alternative for onboard hydrogen storage in the maritime sector, when compared to compressed gas and liquid hydrogen storage. This is done by modelling different hydrogen supply and onboard storage scenarios and evaluating their levelized cost of hydrogen variables. The levelized cost of hydrogen for each case is calculated considering the main components that are required for the refueling infrastructure and adding up the costs of hydrogen production, compression, transport, onshore storage, dispensing, and the cost of the onboard tanks when known. The results show that the simpler refueling needs of metal hydride-based onboard tanks result in a significant cost reduction of the hydrogen handling equipment. This provides a substantial leeway for the investment costs of metal hydride-based storage, which, depending on the scenario, can be between 3400 - 7300 EUR/kg_{H2} while remaining competitive with compressed hydrogen storage.

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1. Introduction

Hydrogen is expected to play a central role in the transition to a climate neutral economy [1] and it seen as the ideal energy vector to decarbonize hard-to-electrify transport segments and achieve zero-emission mobility [2,3].

One of the barriers limiting green hydrogen to offset fossil energy carriers is its high cost of production, distribution, and storage. This barrier becomes even more challenging for transport applications where the demand is geographically distributed and, at least in an initial market stage, limited to small-to-medium volumes [4]. Indeed, for a volume-limited distributed demand, hydrogen might be produced locally thus losing the benefits of the economy of scale [5], while higher quantities produced at a centralized remote location must be transported to the end-use location [6]. Both alternatives increase the price of the supplied hydrogen. In addition, significant costs stem from the need to efficiently store hydrogen. Typical approaches to address such a need are hydrogen compression, liquefaction, or transformation to other hydrogen-containing compounds, such as ammonia and methanol, all of which add extra energy consumption, costs, and complexity to the fuel supply [7].

Hydrogen can also be efficiently stored when hydrogen reacts with selected metals or alloys and forms metal hydrides (MHs) [8–10]. The reaction is exothermic and, when reversible, allow the use of MHs as "sponges", desorbing hydrogen when heated and absorbing hydrogen when exposed to hydrogen and cooled. However, this storage method has not yet found practical uses for mobile applications due to the high gravimetric density of MH-based tanks [11]. This disadvantage can be offset, at least partially, when using it in maritime applications as the added weight could theoretically be a part of the ships fixed ballast weight. An additional complication is the need of integrating MH-based hydrogen storage with a heat management system, preferably based on a waste heat stream [12] to allow the hydrogen to be desorbed from the MH. Promising modelling results for MH storage tanks thermally integrated with a Polymer Electrolyte Membrane Fuel Cell (PEM-FC) under selected maritime operational profiles have been reported by Cavo et al. [13]. It is shown there that the thermal power required for the desorption of the hydrogen needed for the operation of the PEM-FC is about 25% of the heat produced by the PEM-FC system. The thermal integration adds additional complexity and, in turn, capital expenditure (CAPEX) for the installation. The latter, which must also include the initial cost of the hydrogen absorbing material, is typically much higher than the CAPEX for a compressed hydrogen storage tank. Such a drawback severely limits the introduction and implementation of hydrogen storage solutions based on MH.

Levelized cost calculations are a well-established techno-economic method to compare economically competing options when delivering a given commodity. The method provides a cost per commodity delivered, considering the assets lifetime as well as including both the investment and operating costs. It is broadly used when comparing electricity production costs, but it can also be used for many other commodities. In this work, the levelized cost of hydrogen (LCOH) is considered for different refueling and storage alternatives within the maritime transport sector.

The LCOH is a powerful tool to decompose the hydrogen costs per component and understand the important cost drivers. For instance, by employing LCOH calculations, refueling was identified as a major cost driver for light duty fuel cell vehicles equipped with 700 bar storage tanks serviced by a small refueling station with a daily demand of 100 kg_{H2}, contributing almost 10 USD_{2017}/kg_{H2}. More than half of such cost is attributed to hydrogen compression, while hydrogen refrigeration is the second largest cost item [14].

Additionally, in a recent assessment by Ku et al. [15] reviewing refueling 350 bar tanks on vans, buses and trucks the cost of the refueling infrastructure was shown to be as low as 0,5 USD_{2022}/kg_{H2} at an infrastructure utilization rate of 83%. A more representative utilization rate of 12,5%, results in a cost of the refueling infrastructure spanning between 3 and 4,5 USD_{2022}/kg_{H2}. The same work concluded that the cheapest refueling alternatives are compression and regasification of liquified hydrogen. It is worth noting that the two studies mentioned above did not consider costs for hydrogen production, liquification and transport.

Another parameter to consider when evaluating LCOHs is the utilization rate. Some studies have focused on the benefits of increased utilization rate with limited number of vehicles and slower refueling rates over longer time periods for public bus fleets [16].

Ulleberg & Hancke [17] confirmed that utilization rate and dispensing pressure are important cost contributors. Their analysis was extended also to include the production facility and shows the advantage of local hydrogen production at low daily demands.

The maritime sector is identified as one of the more difficult sectors to decarbonize. Even if compressed hydrogen storage is too bulky for deep sea shipping, it can play an important role in coastal shipping [18]. This is demonstrated by the initiation of several demonstration projects, such as: Sea Change, a passenger ferry in San Francisco (USA) [19], FPS Maas, an inland container vessel in Belgium [20], and With Orca, a bulk ships for operation in Norway [21]. Additionally, Mojarrad et al. recently reported on a techno-economic model for a zero-emission hydrogen ferry, which compares the operating expenses (OPEX) for compressed or liquid hydrogen, including the case for a superconducting propulsion system [22].

While there is very limited knowledge regarding the refueling of maritime vessels, it is reasonable to assume that the refueling infrastructure will be an important cost driver just as for road transport and that limiting its cost can be beneficial for accelerating the implementation of hydrogen-powered vessels.

One way to limit the cost of the refueling infrastructure is to find ways to compress the hydrogen more efficiently, either by innovative non mechanic compression technologies, such as electrochemical or adsorption compressors [23], or produce hydrogen at higher pressures with, for instance, high-pressure PEM electrolyzer [24]. Alternatively, storing hydrogen onboard at significantly lower pressures in MH-based tanks can simplify the hydrogen handling onshore and with that reduce the costs of the refueled hydrogen. While the latter is an attractive possibility, it is still unclear whether the reduced costs of a simplified refueling infrastructure can counterbalance the typically high CAPEX of a hydrogen storage solution based on MH.

1.1. *Objectives and novelty*

The aim of this work is to consider the case of a small hydrogen powered maritime vessel and estimate the CAPEX limit for a MH storage and its auxiliary systems within which it can be economically competitive with more established storage methods such as compressed and liquid hydrogen. This is done through a novel approach and by including both the onshore infrastructure and the onboard tank in a techno-economic two-step workflow. First, a mass flow model is used to dimension the onshore refueling equipment needed to refuel compressed hydrogen and MH tanks. Then, to evaluate different refueling scenarios, the LCOH is calculated considering hydrogen production, the operation of the main components that are required for the onshore refueling infrastructure (hydrogen compressors, onshore hydrogen storage, and dispensers), as well as the onboard hydrogen storage tanks. Where required, hydrogen transport cost between production and refueling facilities are included. Different sizes of the components are also considered depending on low- and higher daily demand scenarios. Eventually, the LCOH for each scenario is used to extrapolate the cost below which MH-based tanks are the most economically favorable onboard hydrogen storage solution.

The results should provide a good indication on the targets, in terms of costs, that researchers, developers and producers of metal hydride tanks should aim to make hydrogen storage in metal hydrides a solution worth considering from an economical perspective. To the best of our knowledge, this is the first time that a LOCH calculation has been applied for evaluating a refueling scenario that includes hydrogen storage in metal hydrides. Even if the case considered in this work is limited to a very specific segment of the maritime sector, this approach can be extended and applied to other cases including different transport sectors.

2. Refueling scenarios

The main aim of this techno-economic analysis is to quantify how the cost of the different hydrogen supply alternatives varies depending on how hydrogen is stored onboard a small vessel. The comparison includes the necessary steps to produce, handle and transfer hydrogen onboard, as well as the cost of the compressed hydrogen onboard tank and its integration costs.

The approach considers three onshore supply alternatives for three onboard tank types (Fig. 1). The supply alternatives are local production of compressed hydrogen gas (Case A), centralized production and transport of compressed hydrogen gas (Case B) and central production and transport of liquid hydrogen (Case C). The onboard storage alternatives are hydrogen in a metal hydride (MH), compressed hydrogen gas (CGH2) and liquid hydrogen (LH2). This set of scenarios for maritime transport applications is chosen among the many different combinations of how hydrogen can be produced, transported, and refueled.

Two different supply alternatives representing low- (100 kg_{H2}/day) and high-volume demand (1500 kg_{H2}/day) are discussed. All the hydrogen is refueled within 4 h during the night. Such a refueling pattern is meant to reflect the

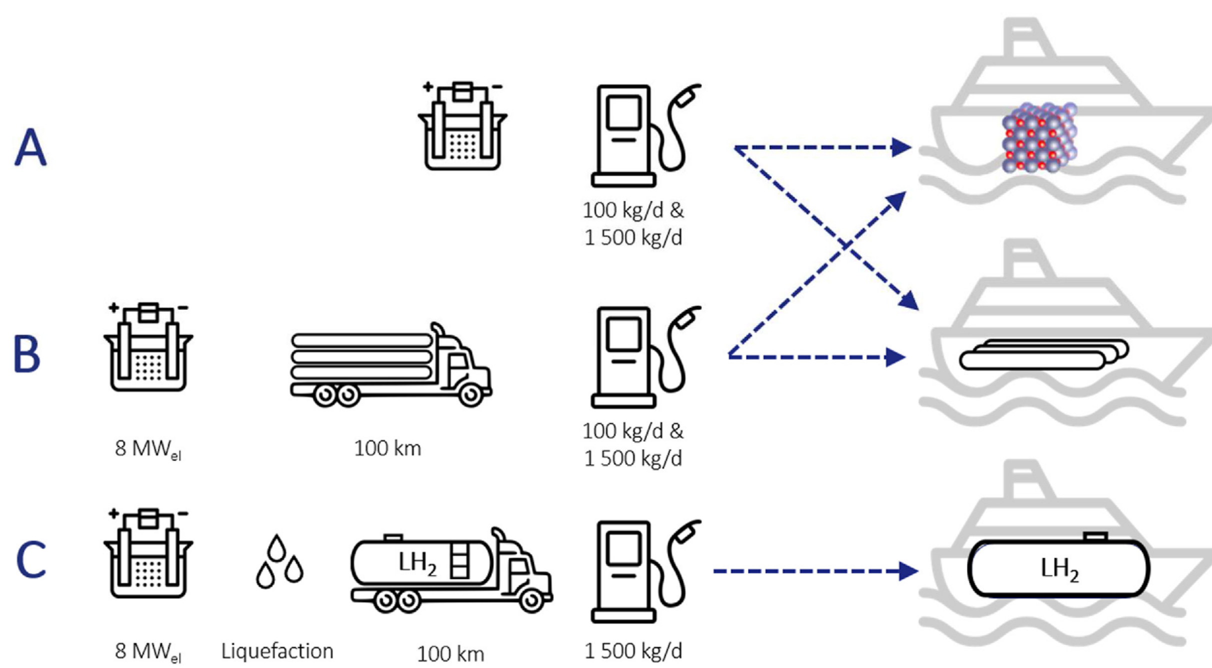

Fig. 1 – Simplified overview of hydrogen supply alternatives (Case A, B and C) for the five high-volume (1500 kg_{H2}/day) and four low-volume (100 kg_{H2}/day) scenarios which are considered in this work. Compressors and onshore hydrogen storage are not included in the figure.

operation of small vessels which sail during the day and are moored at port during the night. This leads to refueling rates of 0.42 and 6.25 kg_{H2}/min for 100 kg_{H2} and 1500 kg_{H2} demands, respectively. The low volume demand is assumed for a single, small vessel, while the high-volume demand is assumed for three larger vessels which refuel simultaneously. The demand is assumed to be satisfied 5 days a week for 50 weeks a year, which sums up to a yearly demand of 25 ton_{H2}/year and 375 ton_{H2}/year for the low and high demand scenario, respectively.

To simplify the analysis, hydrogen production was considered to be only by water electrolysis operating at a constant power price. In addition, the analysis does not consider the interaction between the onboard storage and the powertrain, except with the assumption that a sufficient waste heat supply is available to release hydrogen from the metal hydride storage via the endothermic desorption reaction. This results into no additional operational costs for the metal hydride storage in comparison with compressed hydrogen storage.

The cost of MH-based and LH2 onboard tanks is not included in the analysis, due to the limited number of such solutions available on the market and the consequent challenge to set a representative price. In addition, MH tanks can be based on different metals and alloys which can have different prices and operate at very different temperatures and hydrogen pressures. This significantly affects the final cost of the MH-based tank, as well as the cost of the tank heat management system. The metal hydride tanks considered in this work are based on material, such as TiFe-based alloys, that can reversibly store hydrogen in a temperature range between 0 and 50 °C and can absorb hydrogen at pressures lower than 50 bar.

2.1. *Local production of compressed hydrogen (case A)*

The local production of compressed hydrogen at the harbor is shown as case A in Fig. 1 and can supply both a MH and a CGH2 onboard storage tank. The onshore equipment considered in this scenario includes an electrolyzer, a compressor, onshore hydrogen storage units, and a dispenser per vessel. The electrolyzer has a capacity of either 0.2 MW_{el} or 3.4 MW_{el} for the low-demand or high-demand scenario, respectively, while the dimensioning of other components varies depending on the capacity and the onboard storage solution.

To refuel an onboard CGH2 storage tank, cascade filling is assumed. A more detailed description of cascade filling will be given in Section 3 *Model assumptions and Methods*.

A drawback for a local production unit is the smaller size of the installation, which cannot take advantage of the economy of scale associated with electrolyzers. In this case, it is assumed that there is easily accessible power grid, water and space to install the electrolyzer, compressor and buffer storage at or nearby the dock.

2.2. *Central production of compressed hydrogen (case B)*

Hydrogen can be produced remotely on a larger scale, possibly at more feasible conditions, and then transported to the refueling location in compressed form. Such alternative is explored in this work by large-scale production of hydrogen with an 8 MW_{el} (electric power) electrolyzer, equivalent to 3.6 ton hydrogen per day. Hydrogen from this central production location is compressed at the production facility to 350 bar and transported for 100 km by a truck equipped with a transport module. The concept is illustrated as case B in Fig. 1. The possibility to install the electrolyzer in a more convenient location with locked-in cheap electricity or the possibility to offset the bi-products from the electrolyzer in the form of oxygen and waste heat, can be additional drivers to choose a production location which is not nearby the harbor.

An important prerequisite for this scenario is that there is other hydrogen demand nearby which motivates the construction of such a large production facility and that the plant operators find it feasible to sell smaller hydrogen volumes for a secondary demand such as the vessels considered in this work.

For Case B, it is assumed that hydrogen is delivered to the port by the same hydrogen transport module when refueling both MH and CGH2 onboard storage tanks. However, the harbor refueling infrastructure will differ for the two onboard storage alternatives.

To refuel the MH onboard storage, the transport module can be directly connected to (or equipped with) a suitable dispenser which safely empties the transport module into the MH onboard storage until reaching close to the pressure parity with the operating pressure of the metal hydride tank.

As for refueling the CGH2 onboard storage tank, a part of the hydrogen in the transport module can be refueled in the same manner as for MH onboard storage. However, as the pressure decreases in the transport module and increases in the onboard storage, the pressure will equilibrate when the transport module is partially emptied, and onboard storage only partially filled. Therefore, additional refueling components are required. This work explores the options for cascade refueling and booster compressor.

With a cascade system the hydrogen from the transport module is reconsolidated into a cascade storage system with the help of an onsite compressor before it is transferred to the onboard CGH2 storage through a dispenser. This means that the dispenser needs to manage higher pressures as well as a more sophisticated control system to efficiently use a combination of direct overflow from the transport module and switching between the cascade tanks.

Alternatively, a booster compressor can be used to directly withdraw hydrogen from the transport module and fill the onboard storage. By increasing the compressor size, the entire step of pressure consolidation in a cascade storage can be skipped.

2.3. *Central production of liquified hydrogen (case C)*

In this scenario, liquid hydrogen is both produced and liquified at a remote production site and transported to the harbor (Case C in Fig. 1). For the sake of simplicity, the same size of electrolyzer and distance from harbor as in Case B is chosen for the analysis. It is assumed that the capacity of the liquefier matches the hydrogen production volume, which makes it of modest size considering the liquefiers installed during the recent years [25].

3. Model assumptions and methods

3.1. *Modelling framework and tools*

The scope of this work is to estimate how the operation of the different components of the refueling infrastructure affect the LCOH for the different scenarios. Therefore, a simplified modelling approach, which assumes a mass balance throughout the system, is chosen. The temperature of the hydrogen gas is assumed to be constant at 15 °C, allowing for the omission from the model of several thermodynamic effects, for instance the Joule-Thomson effect. With such assumptions in place, Microsoft® Excel® was used to calculate the hydrogen mass and pressure variation for each component at 1 min resolution, as well as to calculate the LCOH of the system. The correlation between hydrogen pressure and density is calculated using the Engineering Equation Solver (ESS) software.

3.2. *Refueling solutions*

To fill an onboard CGH2 tank, the source of hydrogen must always be at a pressure higher than the hydrogen pressure in the onboard tank. This work explores the options of using a cascade system or a booster compressor to achieve this requirement.

The main principle of cascade-type refueling is that hydrogen is refueled in series from several buffer tanks at the hydrogen refueling station (HRS). When an equilibrium is approaching between one of the onshore cascade tanks and the onboard tank, the refueling is switched over to the next cascade tank which has higher pressure, to maintain a pressure difference and by that a mass flow. Thus, the cascade system always requires a base volume of hydrogen and storage size just to build-up the pressure inside the tanks.

Instead of a cascade system, the possibility of using a larger booster compressor is explored for refueling a compressed storage tank in the case B. The booster compressor should be able to deliver the required refueling speed also during the most demanding condition of an almost empty transport module. That is, compressing hydrogen from pressures as low as 50 bar, to an onboard tank max pressure of 350 bar.

Type III or IV tanks with an upper temperature safety limit of 85 °C are typically used for onboard storage of compressed hydrogen. For fast refueling of road vehicles (down to 3 min for a passenger car), precooling of hydrogen is required to ensure that the tank temperature is held within its safety limits. Pre-cooling becomes even more critical for storage at 700 bar as the pressure difference is the driving factor for heat development. There is a scarcity of studies for refueling hydrogen volumes suitable for maritime vessels and a lack of information on when precooling is necessary. Considering that the refueling evaluated in this work is done at 350 bar and during a time window of 4 h, it is assumed that no precooling is required to keep the onboard tank temperature limits. A scenario which includes precooling would significantly increase the costs of the refueling infrastructure [14].

For MH tanks the refueling solution is a simplified version of a cascade system. The similarity is that onshore storage is still done with compressed hydrogen, however during refueling the onboard pressure remains low. Thus, a single buffer tank in which the pressure decreases close to the refueling pressure of the MH onboard storage is enough. For such a buffer tank, the pressure is limited to 200 bar so that the compressor capacity is minimized.

In this work, it is assumed that the metal-hydride storage system is based on an alloy, such as TiFe, which efficiently absorbs hydrogen at 40 bar. This allows a more efficient utilization of the onshore infrastructure compared to onboard storage of compressed hydrogen, as the onshore buffer storage can be emptied to a larger extent and can operate at lower pressures. With reduced pressures and a single tank, the system becomes simpler, with less sophisticated components and a more straightforward control system.

3.3. *Component dimensioning and efficiencies*

When dimensioning the onshore refueling system, the compressor capacity and the onshore storage size are adjusted through iterations to find a suitable component size. This is done by gradually decreasing the component sizes, while ensuring that i) the system can provide enough hydrogen for successfully completing refueling and ii) the hydrogen compression capacity is enough to replenish the buffer/cascade storage system within a day and be ready for a new refueling event the following day.

When storing CGH2 in Case B, where hydrogen is delivered by truck, the delivery of a new hydrogen transport module is assumed to happen simultaneously as the refueling started. For low demand, the pressure levels in the cascade system at the initial state are matched with the level after emptying the transport module at the end of the third day, while for high demand the cascade system is assumed totally full at the beginning of the modelling cycle and aimed to be replenished at the end of it. The transport module is sized to provide a delivery large enough for 3 days when demand is 100 kgH2/day, that is 300 kg_{H2} net (365 kg_{H2} gross) in total. Alternatively, two transport modules carrying 750 kg_{H2} net (910 kg_{H2} gross) each are used when the demand is 1500 kgH2/day. The transport module is considered empty when the pressure reaches 50 bar.

By delivering a new transport module at the start of the refueling, the cascade systems tanks are kept to a minimum size as the greatest volume of hydrogen from the transport module can be used for direct overflow into the onboard storage. In addition, the on-site compressor has the largest time span to empty the previous transport module into the cascade system thus maximizing its utilization rate.

Regardless which onboard storage system is refueled, there will be a pressure drop over the valves and piping during the refueling event. In this work, it is assumed that at least a 10 bar pressure difference is required between the onshore buffer tanks and the onboard tank to ensure the desired refueling speed.

The alkaline electrolyzer including all auxiliary infrastructure is assumed to have an efficiency of 62% and provide 15 bar output pressure after initial compression [5].

The liquification efficiency, considering the plant size, is set to 12 kWh_{el}/kg_{H2} [26].

3.4. Compressor

A central cost driver for the hydrogen supply is the compressor and reducing the maximum operating pressure of the onboard storage solution can significantly contribute to decrease the hydrogen supply cost. It is also a dynamic component where effort needs to be made to model it correctly. Below are laid out the main assumptions and simplifications made in this work for the modelling the compressor.

Hydrogen compressor modelling is based on the work reported in Ref. [27] and is expressed as

$$Power = Z\, \dot{m}\, R\, T\, n \left(\frac{1}{\eta}\right)\left(\frac{k}{k-1}\right)\left(\left(\frac{P_{outlet}}{P_{inlet}}\right)^{\left(\frac{k-1}{n\,k}\right)} - 1\right) \quad (1)$$

where the power demand is given in kJ/s and is calculated based on the mean compressibility factor throughout the compression (Z), mass flow ($\dot{m}$) given in kg-mole/s, the universal gas constant (R), the inlet gas temperature (T) in Kelvin. The power demand accounts for compression over several stages (n) with intercoolers between stages, which cool the hydrogen to the inlet gas temperature (T). The mean compressibility factor is set to 1.07. The inlet gas temperature (T) is set to a constant of 15 °C (288.15 K). The isentropic efficiency (η) is set to 0.89 and the ratio of specific heats (k) to 1.4. P_{Inlet} and P_{outlet} refers to the compressor's inlet and discharge pressures.

The number of stages will vary depending on the design of the suction and discharge pressure and which pressure ratios (P_{out}/P_{in}) a compressor can provide. In this work, it is assumed that all compression work will be done with a diaphragm type compressor. The pressure ratio for this type of compressor varies between 5 and 10 per stage according to established compressor suppliers [28–30]. In this work, a pressure ratio of 7 is assumed.

Diaphragm compressors, together with other types of displacement type compressors, have the characteristic of displacing a constant volume. This means that their mass flow capacity will be directly affected by the suction pressure [31]. This characteristic becomes important to consider when compressor needs to consolidate the pressure from a buffer tank where pressure decreases over time.

Equation (1) considers only the isentropic efficiency. However, in addition, each compression stage results also in mechanical efficiency losses, which typically vary between 2% and 5% per compression stage [32,33].

As the compressor is a crucial part of the refueling system and prone to fail, a redundancy of 3 × 50% compressors in parallel is modelled. For the smallest compressors it was more suitable to select a 2 × 100% compressor set up due to the economy of scale.

3.5. Techno economic method and input values

The techno-economic analysis of the production technologies carried out in this work was done based on the levelized cost of hydrogen (LCOH). It is defined by Ref. [34] as

$$LCOH = \frac{\sum_{t=1}^{n} \frac{I_t + M_t + E_t}{(1+r)^t}}{\sum_{t=1}^{n} \frac{H_t}{(1+r)^t}} \quad (2)$$

where I_t is the initial investment in year t, M_t is the operations and maintenance costs, E_t is the fuel costs, H_t is the hydrogen produced in the year t, r is the discount rate and n defines the system lifetime.

The LCOH is calculated for each component separately depending on its lifetime and usage frequency and stapled upon each other to obtain the final cost of hydrogen. It is a strongly simplified approach as the different components need to work together in a system, but it avoids the challenges connected to determine a suitable system lifetime and the complexity of considering reinvestment of certain components and estimating savage costs for components with long lifetime.

The calculations are made in Euros and the input data is normalized to 2019 rates (inflation and exchange rates). The discount rate is set to 8%. The power price is based on the price level in the NO1 (Oslo) power price area in Norway in 2018, which was in average 44 EUR/MWh [35]. This is representative of the yearly power price during the period 2003–2022, despite the drastic price changes observed in 2022 because of reduced gas supply from Russia to Europe. Indeed, the average yearly power price for the NO1 region over the period 2003–2022 is 43.66 EUR/MWh. In addition, grid investment and its monthly fees needs to be included. Large electrolyzers are assumed to have more opportunities to offset this cost through co-location with power production facilities or other big consumers at beneficial locations relative to the grid, as well as higher capacity factor. On the other hand, smaller actors are more exposed to relatively larger grid investments and/or fees as well as reduced capacity factor. This is accounted for by an additional grid fee of 10 EUR/MWh for centralized electrolyzer and 25 EUR/MWh for local production facility.

The costs of electrolyzers and compressors are differentiated based on size and are taken from Refs. [5,36], respectively. The cost of liquefier is taken from Ref. [37].

The electrolyzers have a significant investment cost. For this reason, it is assumed that high-capacity factors are desirable to enable cost recovery over large volumes of produced hydrogen. This aspect is included in the analysis by assuming that the centralized electrolyzer has a capacity factor of 90%, while the local electrolyzer is operating continuously for the days when the demand is present and is in stand-by the remaining days. It is therefore possible to further reduce the production costs of the local electrolyzer, by increasing its capacity factor, but this was not considered in this work.

The assumed costs of storage and dispenser solutions are shown in Table 1, where the investment costs for the transport storage unit are also indicated. However, this costs only represent the vessels where hydrogen is stored. The costs of truck, fuel and driver salary come on top and they are calculated based on Norwegian cost levels for driving a semi-trailer set-up of a fuel truck [38]. The truck costs include the round-trip and vary depending on how much hydrogen is transported by a single truck.

Table 1 – Costs of storage and dispenser.

Item	Type	Cost [EUR/kg_{H2}]	Ref.
Onshore storage	<350 bar	400	[39]
	<500 bar	729	[39]
Dispenser	<125 kg/h compressed hydrogen	200'000 EUR/unit	[a]
	<125 kg/h metal hydride	100'000 EUR/unit	[a]
H_2 transport module	<350 bar	600	[39]
	Liquid H_2	336	[37]
Onboard storage	<350 bar	720	[40]
	Integration costs of compressed hydrogen tank	720	[40]

[a] Estimated values.

All the equipment has different lifetimes and maintenance costs, which are presented in Table 2. For some of the components, no unambiguous values are found in literature. Therefore, estimated values were used. For example, hydrogen compressors with rotating and bending (diaphragm) are more exposed to failure than, for example, hydrogen storage tanks. This is reflected in both a shorter lifetime and higher maintenance costs compared to other system components. The lifetime of electrolyzer is based on 90 000 operational hours, the lifetime for the remote electrolyzer being shorter due to the higher capacity factor.

For all stationary installations, a cost for engineering, installation and start-up as a share of equipment costs are also added, as done by Chardonnet et al. [41]. It is 50% of the electrolyzer costs for low demand with local production, while it is reduced to 30% for large demand at local and remote, centralized production.

Table 2 – The lifetime and maintenance costs of the different components used in the tecno-economic analysis.

Component	Lifetime [years]	Maintenance costs [% of equipment costs]	Ref.
Electrolyzer - local	15	3%	[42]
Electrolyzer - remote	11	3%	[42]
Liquifier	40	1%	[37]
Compressor	8	6%	[a]
Onshore storage	30	2%	[43]
Dispenser	15	2%	[a]
Onboard storage	30	2%	[43]

[a] Estimated values.

4. Results

4.1. *Mass flow modelling*

Table 3 summarizes the results of the mass flow modelling. For all cases with remote production (Case B) a central compressor and the use of a transport module to deliver the hydrogen to the harbor are included. The central compressor is assumed to compress all the hydrogen produced, requiring a relatively high-power output (112 kW_{el}).

The detailed results for Case A (local H_2 production) and B (remote H_2 production and transport) are presented below. The description is for the low 100 kg_{H2}/day demand. The dynamics remains the same with larger hydrogen demand except for Case B where twice as many hydrogen deliveries are made for a single-day demand instead of a single delivery serving a three-day demand. The modelling results for all the high demand scenarios as well as a case using a booster compressor are shown if Figs. S1–S6 in the Supplementary Information (SI).

4.1.1. *Case A – local production*

The dynamics of an onshore refueling system with local hydrogen production (Case A) is relatively simple when a MH-based onboard storage needs to be refueled (see Fig. 2). A high-pressure buffer tank with a volume of 8.2 m^3 filled with 117 kg_{H2} at 200 bar can be used. Refueling 100 kg_{H2} in 4 h requires a

Table 3 – Summary of modelling results.

Daily demand	Case	Onboard storage type	Compressor HRS			High Pressure onshore storage [kg_{H2}]
			Pressure in - out [bar]	Size [kW_{el}]	Energy [kWh_{el}/day]	
100	A	MH	15–200	6	107	117
100	A	CGH2	15–450	8	181	270
100	B1	MH	–	–	–	–
100	B2	CGH2	50–450	2	14	231
100	B Booster	CGH2	50–350	29	18	–
1500	A	MH	15–200	88	1603	1750
1500	A	CGH2	15–450	126	2725	4110
1500	B1	MH	–	–	–	–
1500	B2	CGH2	50–450	21	250	3000
1500	B Booster	CGH2	50–350	434	288	–

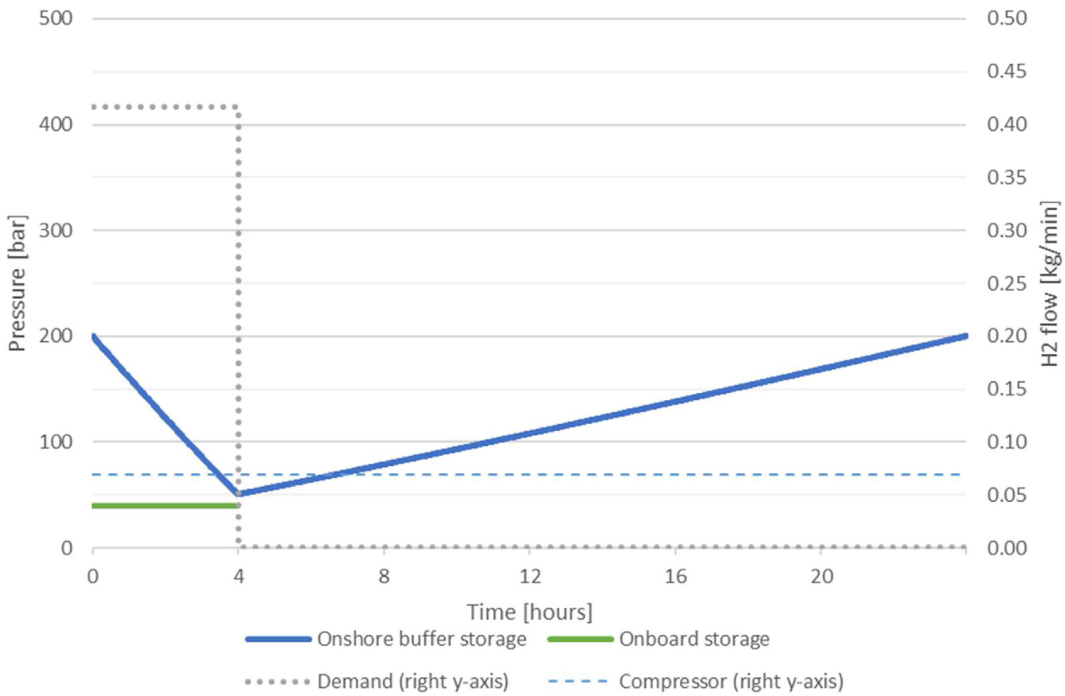

Fig. 2 – Pressure variation and mass flows in the onshore buffer tank for 24 h when dispensing 100 kg_{H2}/day to a metal hydride onboard tank in case A.

constant hydrogen flow from the buffer tank to the onboard MH tank of 0.42 kg_{H2}/min. During the refueling procedure, the onshore buffer tank is progressively emptied and, in order to maintain the pressure inside the buffer tank above the minimum pressure at which the metal hydride onboard storage can absorb hydrogen (about 40 bar), a constant H_2 flow of 0.07 kg_{H2}/min from the compressor to the buffer tank is needed. The pressure inside the buffer tank reaches 50 bar at the end of the refueling operation and, by maintaining the H_2 flow from the compressor to the buffer tank constant at 0.07 kg_{H2}/min, it increases back to 200 bar after 20 h, when a new refueling can be performed. During one such 24-h cycle, the total energy used by the compressor is 107 kWh.

The refueling of the onboard CGH2 tank is more complex, as an onshore cascade storage tank solution is needed. Fig. 3 shows the results from the modelling where all the three cascade tanks are at maximum pressure (450 bar) at the start of the refueling event and are refilled constantly from the local electrolyzer via the compressor throughout the day. When refueling starts, hydrogen flows from the first onshore high-pressure buffer tank to the onboard CGH2 tank at a constant rate of 0.42 kg_{H2}/min, as was the case for the refueling of the metal hydride storage tank. After 133 min (a bit more than 2 h), the pressure in the first onshore buffer tank decreases to 203 bar, while the pressure in the onboard CGH2 tank reaches 193 bar. To fill the onboard tank further, hydrogen must be supplied from a second full onshore buffer tank while the first onshore buffer tank is being refilled. After 199 min from the start of refueling (a bit more than 3 h), the pressure in the second onshore buffer tank decreases to 296 bar, while the pressure in the onboard CGH2 tank reaches 290 bar. The refueling can then be continued with hydrogen supplied from a third full onshore buffer tank and is completed when the pressure in the onboard CGH2 tank reaches 350 bar. The residual pressure in the third onshore buffer tank is 357 bar. When the refueling of the onboard CGH2 tank is concluded, the constant hydrogen flow from the compressor to the first onshore buffer tank is continued. It takes about 11 h (665 min) to refill it completely, after which the second and third onshore buffer tanks are refilled successively, taking 408 and 233 min, respectively. All three onshore buffer tanks will be at full capacity again and ready for a new refueling event 20 h after the previous refueling was completed. The total energy used by the compressor over this 24-h cycle is 181 kWh.

4.1.2. *Case B – centralized production and transport*

Like case A, the refueling of onboard MH tank is relatively simple as the hydrogen transport module is simply drained of hydrogen directly to the onboard storage as can be seen in Fig. 4. As mentioned above, the size of the transport module is large enough to provide hydrogen for 3 days (72 h) in the low demand scenario (100 kgH2/day). The pressure inside the hydrogen transport module is 350 bar at the start of the first refueling (day 1). It decreases to 244 bar at the end of the 4-h refueling and stays constant until the second refueling is started on day 2. The pressure then decreases to 144 bar at the end of the second refueling and to 51 bar at the end of the third refueling (day 3). Since the pressure inside the hydrogen transport module is always above the minimum pressure at which the onboard MH storage can absorb hydrogen, the operation of a compressor is not required during refueling.

As for the refueling of the onboard CGH2 tank in case B, two alternatives are considered. One uses a cascade system, that is one compressor and three onshore buffer tanks, like that considered in case A, while the other alternative uses only a booster compressor.

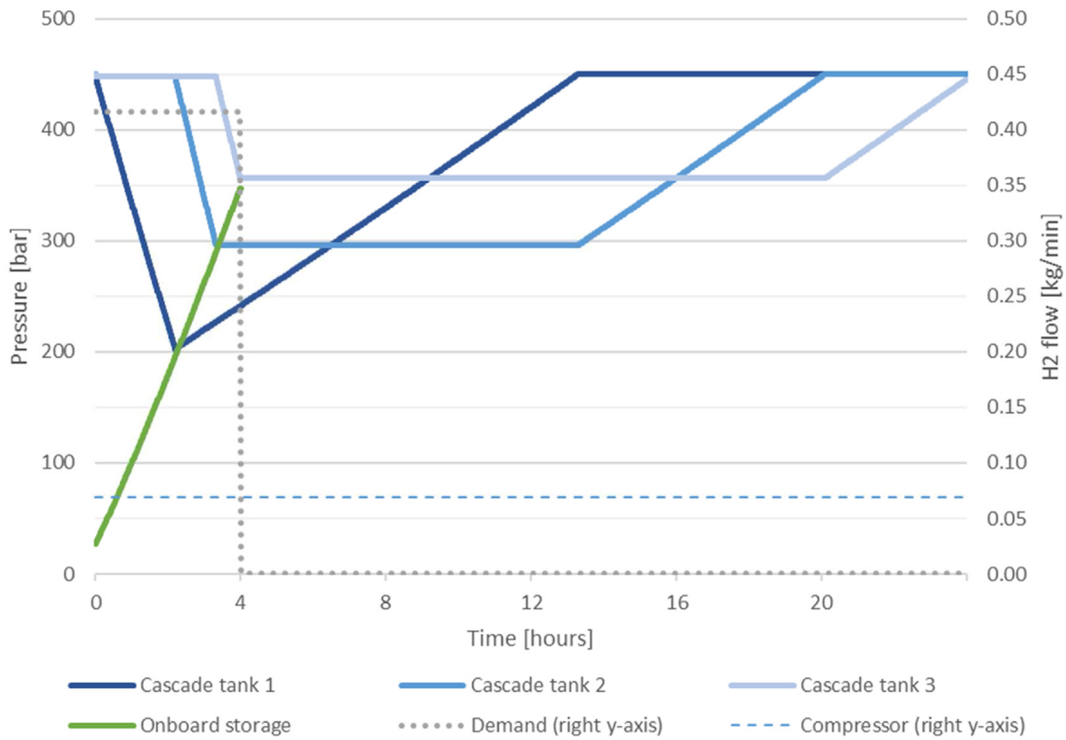

Fig. 3 – Pressure variation and mass flows of a cascade system for 24 h when dispensing 100 kg_{H2}/day to a compressed hydrogen onboard tank in case A.

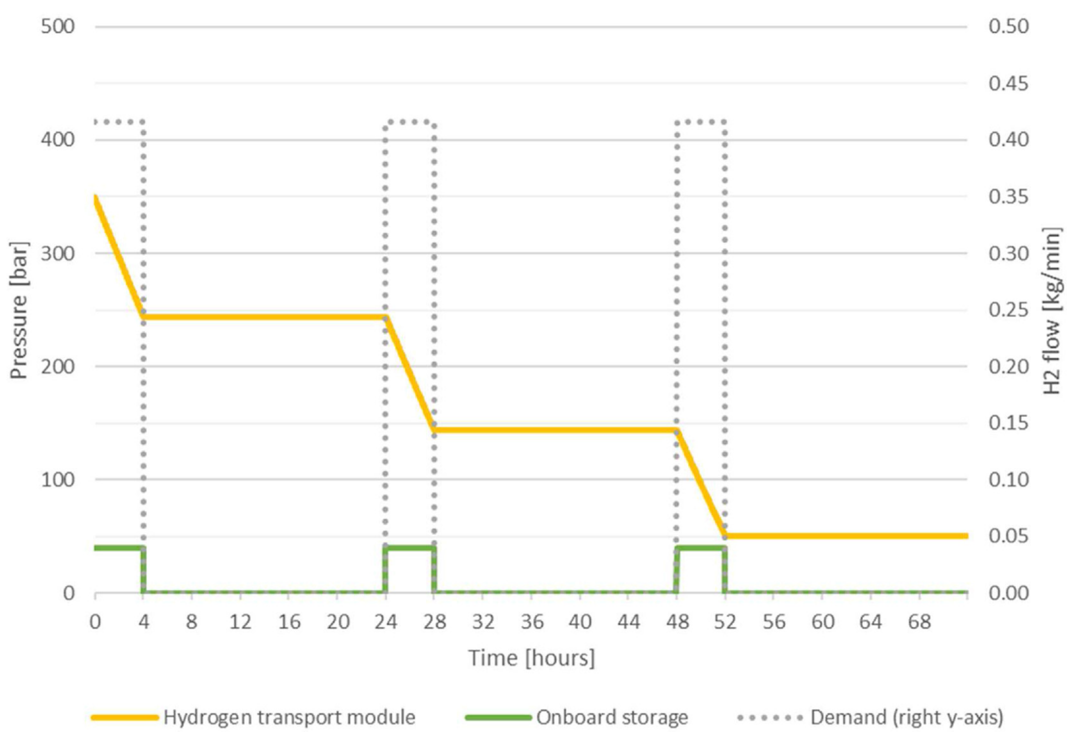

Fig. 4 – Pressure variations and mass flow of the hydrogen transport module for 72 h when dispensing 100 kg_{H2}/day to a metal hydride onboard tank in case B.

The operations with a cascade system become even more complex compared to case A since the mass flow capacity of recuperating compressors (piston or diaphragm type) depends on the supply pressure, which for the hydrogen transport module, decreases over time. This results in a reduction of the compressors capacity as the pressure decreases in the hydrogen transport module. This is shown in Fig. 5, which plots the changes of pressure for the transport module, the three high-pressure onshore buffer tanks of the cascade system, and the onboard CGH2 storage tank. The pressure data is given as a function of time over the course of the 72 h serviced by the transport module and is shown together with the hydrogen flow from the compressor connecting the transport module with the three onshore buffer tanks.

The initial hydrogen pressure inside the three onshore buffer tanks is 450, 360 and 300 bar, respectively. These pressure levels are chosen so that they match the pressure and mass balance in the tanks reached at the end of the previous 72-h cycle as the remaining useable amount of hydrogen in the preceding transport module is transferred via the compressor.

Refueling is started by directly connecting the fully pressurized transport module (350 bar) to the onboard CGH2 tank to be refueled and bypassing the compressor. After 179 min, the pressure in the transport module decreases to 271 bar, while the pressure inside the onboard CGH2 tank increases to 261 bar. Refueling is then continued from the next buffer tank with the lowest pressure. Thus, the buffer tank with 300 bar briefly fills the onboard tank until the pressure in the buffer tank and in the onboard CGH2 tank reach 274 bar ($t = 188$ min). The buffer tank with initial pressure of 360 bar is then used. After 208 min from the start of refueling, the pressure in the second onshore buffer tank sinks to 312 bar the onboard CGH2 tank reaches a pressure of 302 bar. Refueling is completed with hydrogen provided for 32 more min (until $t = 240$ min) from the buffer tank with the highest initial pressure (450 bar), which eventually has a pressure of 372 bar. As in Case A, all three onshore buffer tanks must be filled up again and be ready for a new refueling event after 20 h. However, in this case, hydrogen is supplied from the transport module with a constantly decreasing supply pressure. The flow from the compressor is therefore not constant and varies between 0.11 and 0.06 kg_{H2}/min. The energy consumed by the compressor during the first refilling of the onshore buffer tanks, which lasts altogether 693 min, is 3.40 kWh. The three buffer tanks are filled up at maximum pressure (450 bar) after approximately 14 h since the start of the refueling operations.

The second and third refueling are carried out similarly. The only difference from the first refilling is that the pressure in the transport module and in turn the flow from the compressor are not constant. Therefore, the switch of flow from the transport module and from one buffer tank to another occurs at different refueling times and pressures of the onboard tank. During the second refueling, hydrogen will be supplied from the transport module and the buffer tanks for 100 min, 83 min, 45 min and 12 min, respectively. During the third refueling, hydrogen will be supplied from the transport module and the buffer tanks for 44 min, 101 min, 59 min and 36 min, respectively. As for the compressor, it is turned on again during the second refueling, providing

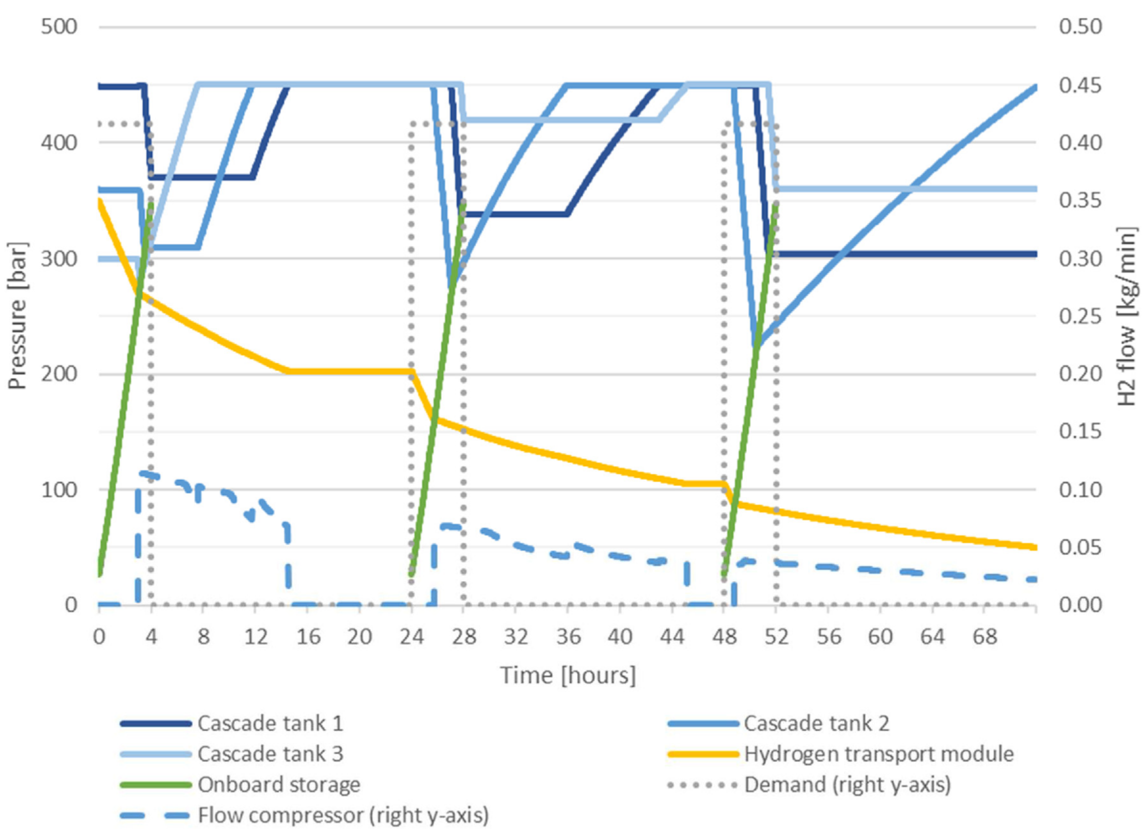

Fig. 5 – Pressure variation and mass flows of the hydrogen transport module and the cascade system for 72 h when dispensing 100 kg_{H2}/day to a compressed hydrogen onboard tank in Case B.

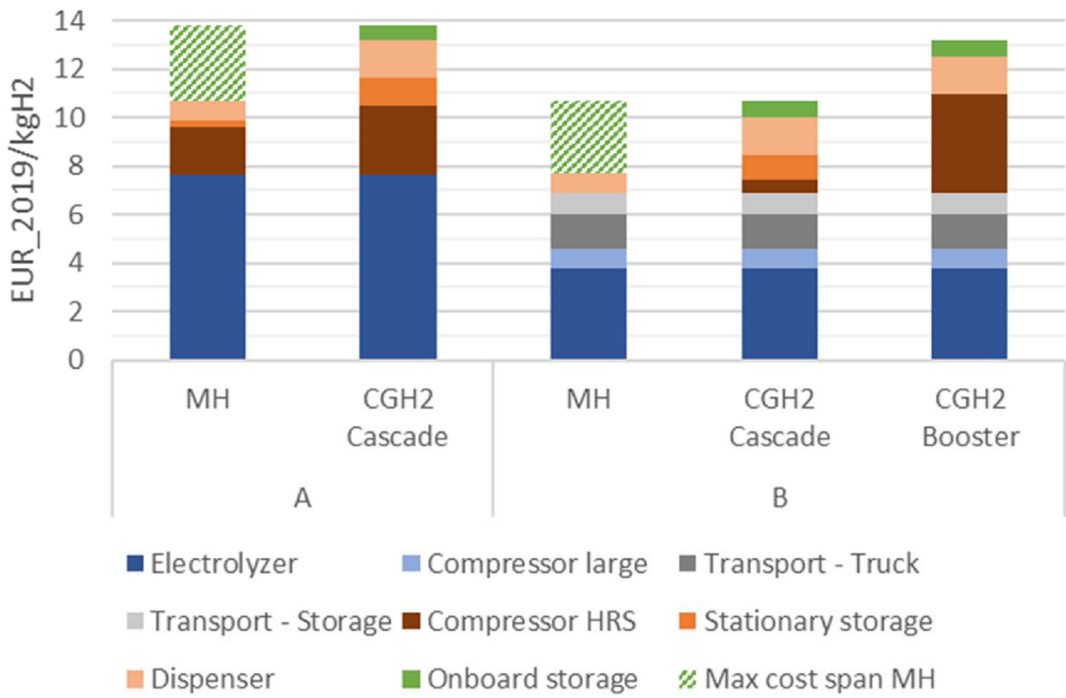

Fig. 6 — The cost structure for delivered hydrogen for the different cases when the demand is 100 kg_{H2}/day.

hydrogen for about 19.5 h with an average H_2 flow of 0.05 kg_{H2}/min and consuming 13.29 kWh, until the buffer tanks are filled up again. The compressor will be turned on once more during the third refueling, providing hydrogen for almost 23 h with an average H_2 flow of 0.03 kg_{H2}/min and consuming 26.06 kWh. The transport module is disconnected from the refueling infrastructure after 72 h. At that point, the H_2 pressure inside the three onshore buffer tanks is 450, 360 and 300 bar, respectively, which match the starting conditions. The total energy consumed by the compressor over the 72-h period is 42.75 kWh, corresponding to an average of 14.25 kWh/day.

Using a booster compressor can be an alternative to the cascade system. In this case, the three onshore buffer tanks are no longer required, and operations are significantly simplified. Indeed, the booster compressor is activated only during refueling when the pressure in the transport module falls below the pressure reached in the onboard compressed hydrogen tank. Since the hydrogen in the transport module is progressively transferred over the course of the 72 h, it will operate for longer periods depending on whether the first, the second or the third refueling is being carried out. In particular, during the first refueling, the booster compressor is switched on when the pressure in the onboard tank reaches 261 bar (271 bar in the transport module) and operates for 60 min consuming 2.29 kWh. During the second refueling, it is switched on when the pressure in the onboard tank reaches 183 bar (193 bar in the transport module) and operates for 116 min consuming 11.35 kWh. Eventually, during the third refueling, it is switched on when the pressure in the onboard tank reaches 109 bar (118 bar in the transport module) and operates for 172 min consuming 39.66 kWh. The total power consumed by the booster compressor over the 72-h period is 53.30 kWh, corresponding to an average of 17.77 kWh/day.

4.2. *Techno-economic comparison*

Fig. 6 shows the LCOH for the different cases when the demand is 100 kg_{H2}/day, while Fig. 7 shows the LCOH for a demand of 1500 kg_{H2}/day. As mentioned above, the costs for onboard MH tank is unknown. This means that the gap between the LCOH to refuel the onboard MH tank and the lowest LCOH for refueling the onboard CGH2 storage, represents the cost ceiling for the metal hydride onboard tank to maintain competitiveness. Such a cost ceiling for the onboard MH tank should also include the necessary auxiliary components to allow a proper heat management system.

With a low daily demand both the hydrogen production and handling costs contribute to a high final LCOH (see Table 4 and Fig. 6). However, the simpler hydrogen handling for refueling the onboard MH tank results in a significant cost reduction of the onshore hydrogen handling equipment. Indeed, for refueling the onboard MH tank in case A, the stationary onshore buffer storage contributes with 0.3 EUR/kg_{H2} to the final LCOH, the compressor contributes with 2.0 EUR/kg_{H2}, and the dispenser with 0.8 EUR/kg_{H2}, adding up to 3.1 EUR/kg_{H2}. On the other hand, for the cascade-type refueling of the c onboard CGH2 tank in case A, the same components contribute with 5.5 EUR/kg_{H2} to the final LCOH (1.2 EUR/kg_{H2} for the onshore buffer storage, 2.8 EUR/kg_{H2} for the compressor, and 1.6 EUR/kg_{H2} for the dispenser). This, considering equal hydrogen production costs and factoring in a contribution of 0.6 EUR/kg_{H2} for the onboard CGH2 tank, means that an onboard MH tank can be economically more competitive compared to compressed hydrogen if it contributes to the LCOH with 3.2 EUR/kg_{H2} or less. Considering a technical lifetime of 30 years and maintenance costs (2% of CAPEX) comparable to that of the compressed hydrogen tank,

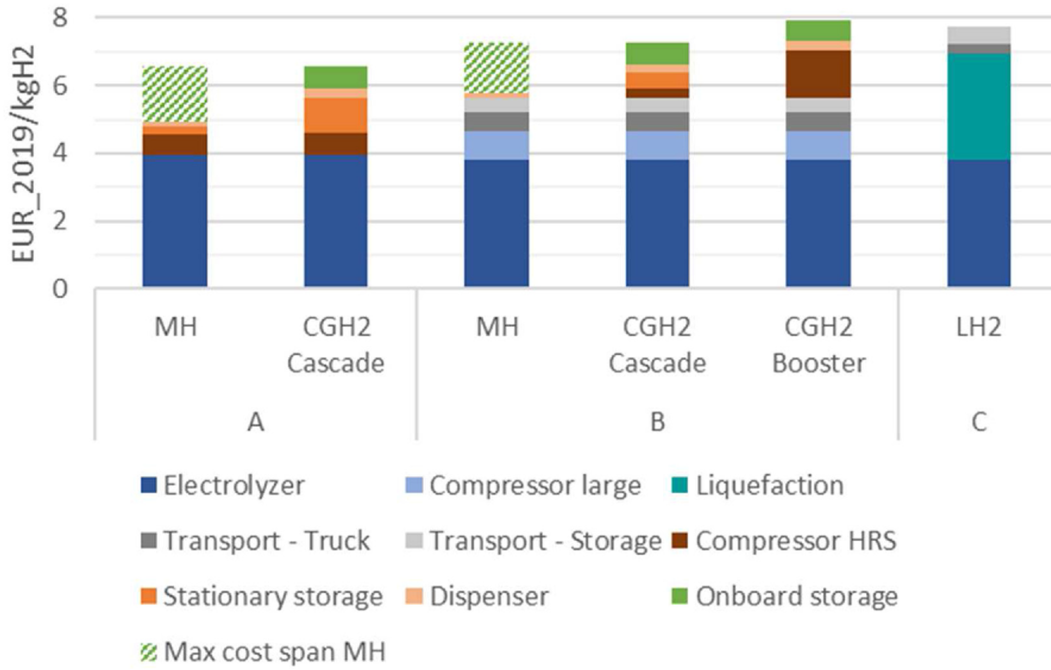

Fig. 7 – The cost structure for delivered hydrogen for the different cases when the demand is 1500 kg_{H2}/day.

Table 4 – LCOH per component for a daily demand of 100 kg_{H2}/day.

Daily demand	100 kgH_2/day				
Case	A		B		
	MH	CGH2 Cascade	MH	CGH2 Cascade	CGH2 Booster
Electrolyzer	7.7	7.7	3.8	3.8	3.8
Compressor large	0.0	0.0	0.8	0.8	0.8
Transport - Truck	0.0	0.0	1.4	1.4	1.4
Transport - Storage	0.0	0.0	0.9	0.9	0.9
Compressor HRS	2.0	2.8	0.0	0.5	4.1
Stationary storage	0.3	1.2	0.0	1.1	0.0
Dispenser	0.8	1.6	0.8	1.6	1.6
Onboard storage		0.6		0.6	0.6
Max cost span MH	3.2		3.0		
Total	10.7	13.8	7.7	10.7	13.2

this corresponds to a CAPEX for the MH storage system, including the necessary auxiliary heat management system, of 7264 EUR/kg_{H2}. Despite being significantly higher than the CAPEX for CGH2 storage (1440 EUR/kg_{H2}, see Table 2), this represents the threshold under which MH-based storage is economically more competitive compared to compressed hydrogen-based storage solutions.

A similar conclusion can be drawn for case B. A higher contribution to the LCOH for the components needed to refuel the onboard CGH2 tank (compressor, stationary cascade storage, and dispenser) is expected. That is 3.2 EUR/kg_{H2} compared to 0.8 EUR/kg_{H2} for the onboard MH tank which requires only a dispenser when refueling is carried out from a transport module. Then, in this case, the onboard MH tank can be economically competitive compared to CGH2 if it contributes to the LCOH with 3.0 EUR/kg_{H2} or less. This corresponds to an overall CAPEX of the MH-based storage, including the auxiliary heat management system, of 6910 EUR/kg_{H2}.

For a larger demand of 1500 kg_{H2}/day, the overall hydrogen costs are reduced due to economy of scale (see Table 5 and Fig. 7). The onboard storage of CGH2 becomes more competitive at larger demand volumes due to the reduced cost per capacity unit for larger compressors. Yet, onboard MH-based storage is still the most economically competitive solution if its CAPEX remains below 3751 EUR/kg_{H2} and 3415 EUR/kg_{H2} for case A and B, respectively.

The LCOH for the case of onboard LH2 storage was also considered in the analysis (Case C), but, due to lack of reliable data and references, the cost calculations for this case could not include the costs neither of dispenser nor of the onboard storage. Nonetheless, considering only the costs of hydrogen production, liquefaction, and transport results in an LCOH of

Table 5 – LCOH per component for a daily demand of 1500 kg_{H2}/day.

Daily demand	1500 kgH_2/day					
Case	A		B			C
	MH	CGH2 Cascade	MH	CGH2 Cascade	CGH2 Booster	LH2
Electrolyzer	3.9	3.9	3.8	3.8	3.8	3.8
Compressor large	0.0	0.0	0.8	0.8	0.8	
Liquefaction						3.1
Transport - Truck	0.0	0.0	0.6	0.6	0.6	0.3
Transport - Storage	0.0	0.0	0.4	0.4	0.4	0.5
Compressor HRS	0.6	0.7	0.0	0.3	1.4	
Stationary storage	0.2	1.0	0.0	0.4	0.0	
Dispenser	0.1	0.3	0.1	0.3	0.3	
Onboard storage		0.6		0.6	0.6	
Max cost span MH	1.6		1.5			
Total	4.9	6.6	5.8	7.3	7.9	7.7

7.7 EUR/kg$_{H2}$, which is between the costs levels of refueling with a cascade system or booster compressor. If the costs for the dispenser and onboard storage are included LH2 would most likely become the most expensive alternative in this study.

Finally, it is worth mentioning that if the CAPEX for the MH onboard storage were 1500 EUR/kg$_{H2}$ and its lifetime and OPEX were comparable with the CGH2 onboard storage, MH onboard storage would contribute to the LCOH with 0.7 EUR/kg$_{H2}$.

5. Discussion

The main findings of this work show that the onshore refueling infrastructure for hydrogen-powered vessels can be significantly simplified when refueling an onboard MH tank which requires a constant refueling pressure of about 40 bar. This should be compared with pressures over 400 bar which are needed to refuel a 350 bar CGH2 tank with a cascade filling system. The reduced cost of the onshore infrastructure for refueling a MH-based tank allows for a significantly higher cost of the tank itself relative to compressed hydrogen onboard tank, while the total system costs remain competitive. A simple sensitivity analysis shows that, if the hydrogen absorption pressure of the MH is either 10 or 80 bar instead of 40 bar and the size of the buffer storage and transport module is adjusted accordingly, the impact on LCOH is < 0,1 EUR$_{2019}$/kg$_{H2}$ for a daily demand of 1500 kg$_{H2}$.

With a daily demand of 100 kg$_{H2}$ per day (Case A), the economy of scale results in a strongly pronounced difference between the local (small-scale) and remote (large scale) production alternative. Both production and compression are much more feasible at a large-scale facility, and the modelled additional transport cost is of less importance. The cost benefit of centralized production disappears if the demand increases to 1500 kg$_{H2}$ per day (Case B) and local production becomes marginally more profitable than transporting from a remote production hub.

When hydrogen is supplied from a remote, centralized source, the local refueling infrastructure for onboard MH storage is kept to a minimum with just a dispenser. However, a slightly larger saving in comparison with onboard CGH2 storage is achieved for local production, where the refueling cost for compressed hydrogen, which are driven by the costs of the compressor and storage, are the largest.

The costs of the refueling infrastructure for compressed hydrogen in the current analysis spans between 1 and 5,5 EUR/kg$_{H2}$. The cost in the most expensive case is driven by the small daily demand (100 kg$_{H2}$/day) which boosts the cost of the compressor. The refueling costs remains significantly lower than the estimates by Ref. [14] for refueling station filling 700 bar passenger cars with same daily demand. The estimates of refueling costs of compressed hydrogen are matching or lower than previous estimates made for vans and trucks by Ref. [15]. Considering that maritime vessels refuel larger volumes with a single dispenser, the cost levels of refueling compressed hydrogen are relatively in line with results presented in previous studies which focused on road vehicles.

The results were obtained through a simple mass balance and compression model and simplified calculation of levelized cost of hydrogen where error sources of each step should be considered. The mass balance and compression model assume constant massflow and temperature during refueling, however both can mutually induce errors. Current refueling standards for compressed hydrogen are based on constant pressure increase, which in turn is dependent on temperature development and the non-ideal gas behavior of hydrogen. In addition, the temperature development throughout the refueling and in the onboard CGH2 tank also impacts the final component sizing, such as compressor size and need of precooling.

A possible pre-cooler would consist of a refrigerating unit and a heat exchanger which cools the hydrogen prior to the dispenser. For rapid refueling of small onboard tanks in hydrogen fueled passenger cars the hydrogen is pre-cooled down to - 40 °C [44], however the pre-cooling requirements can vary with the refueling speed and hydrogen tank geometry [45,46]. Ku et al. [15] used an open access tool to estimate the cost of precooling in a HRS for heavy duty trucks equipped with CGH2 storage tanks. By applying the high demand profile used in this work (1500 kg$_{H2}$/day), the same open access tool used by Ku et al. shows that the components for precooling account for 6–11% of the HRS portion of the LCOH. Comparing this result to the most similar case in this study, that is Case B with a CGH2 cascade system, the addition of precooling to the refueling infrastructure would increase the LCOH by approximately 0.1 EUR$_{2019}$/kg$_{H2}$. Nevertheless, the need and capacity of precooling and in turn a more accurate estimate of its costs for the scenarios investigated here require a careful description of the temperature development in the onboard tank, which is outside the scope of this article.

Another important factor not considered in this analysis is the need of onshore space for the refueling infrastructure and its resulting costs per area unit. Further analysis is needed to investigate which system becomes the most compact and with the smallest safety zones, as areas at and nearby docks are often limited and expensive.

Finally, it is worth mentioning that the hydrogen tank swapping technology has been left outside the scope of this work. However, it would be of relevance to include it in future studies as it has been the chosen solution in recently announced retrofitted and newly built hydrogen powered vessels [20,47]. In such a case, the analysis needs to factor in the access and operation to a crane that can swap the hydrogen storage tanks in and out of the vessels. Additionally, increased investment costs for onboard storage should be considered. Since at least two tanks are needed for this solution (one tank is being refueled onshore while the other is in operation onboard the vessel), the investment costs for onboard storage are at least doubled. On the other hand, the duration of refueling is not limited to the time when the vessel is moored and can be extended significantly. This might result in a simpler infrastructure, as onshore buffer tanks might no longer be required.

6. Conclusions

Hydrogen refueling is a complex process which in this work has been simplified by just accounting for mass balances, pressure, and compressor work. Combined with a simplified levelized cost of hydrogen calculation an overview of component costs is identified for different demand volumes and supply options. At small demands the costs are significantly higher and transport of hydrogen from a remote production hub should be preferred. For larger demands the costs of both local and remote production are reduced and relatively similar for the two cases.

Solid state storage in metal hydrides can be advantageous from a system perspective as they require only low and constant pressure at refueling. These requirements significantly simplify the refueling infrastructure and the costs induced by it. Even if the storage in metal hydride tanks onboard ships has been sparsely investigated, their investment costs can be up to 7000 EUR/kg_{H2} in the most favorable scenario and, at a system level, still be competitive with compressed hydrogen storage.

Such benefits can be achieved in the maritime sector when the high gravimetric density of metal hydride tanks is not a drawback and might be used as ballast weight for the vessel.

The conclusions of this work should be evaluated considering the simplified modelling framework for both component sizing and cost calculations. Thus, they provide only an indication of the potential cost benefits of one storage solution over another. To understand in detail and capitalize on the potential of solid-state hydrogen storage in maritime applications, broader studies which include mapping the safety aspects and onboard system integration, need to be carried out in more detail.

Declaration of competing interest

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

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Appendix A. Supplementary data

Supplementary data to this article can be found online at https://doi.org/10.1016/j.ijhydene.2023.08.313.

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