

Article

Hydrogen as a Maritime Fuel—Can Experiences with LNG Be Transferred to Hydrogen Systems?

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Abstract: As the use of fossil fuels becomes more and more restricted there is a need for alternative fuels also at sea. For short sea distance travel purposes, batteries may be a solution. However, for longer distances, when there is no possibility of recharging at sea, batteries do not have sufficient capacity yet. Several projects have demonstrated the use of compressed hydrogen (CH₂) as a fuel for road transport. The experience with hydrogen as a maritime fuel is very limited. In this paper, the similarities and differences between liquefied hydrogen (LH₂) and liquefied natural gas (LNG) as a maritime fuel will be discussed based on literature data of their properties and our system knowledge. The advantages and disadvantages of the two fuels will be examined with respect to use as a maritime fuel. Our objective is to discuss if and how hydrogen could replace fossil fuels on long distance sea voyages. Due to the low temperature of LH₂ and wide flammability range in air these systems have more challenges related to storage and processing onboard than LNG. These factors result in higher investment costs. All this may also imply challenges for the LH₂ supply chain.

Keywords: hydrogen; safety; cryogenic; LNG; maritime; fuel



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1. Introduction

At present, there are 198 liquefied natural gas (LNG) fueled ships in operation in the world, and further 277 in order [1]. Today, LNG is the most environmentally friendly fossil fuel on the market for maritime purposes [1]. LNG fuels produce no SO_x emissions, low particle emissions and NO_x emissions that are lower than those of conventional fossil fuels [1]. As compared to conventional fuel oils, combustion of LNG reduces the emissions of SO_x and particles by nearly 100%, and NO_x by 85% to 90% [2]. If hydrogen becomes the preferred maritime fuel in the future, the emissions from the maritime industry can be further reduced or eliminated [1].

So far, only a few maritime vessels have applied hydrogen as a fuel. The first vessel to be operated on hydrogen was Hydra in 2000 [3], followed by Zemships in 2008 [4]. Both these vessels were fueled by compressed hydrogen (CH₂). Another well-known demonstration project with CH₂ is the ship Energy Observer, which has been in operation since 2017 [5]. In 2021/2022, a ferry in Western Norway is planned that uses liquefied hydrogen (LH₂) in combination with fuel cells and batteries [6,7]. If this project proceeds as planned, it will probably be the first maritime application of LH₂ as fuel.

LH₂ has been used as rocket fuel in the space industry for decades [8]. However, at present, there are no maritime vessels fueled by LH₂ in operation. Hence, there is no practical experience available regarding LH₂ systems onboard ships. Therefore, in this paper we will discuss the challenges and applicability of LH₂ as a future maritime fuel, based on experiences from LNG systems.

2. Materials and Methods

This work is based on available data in literature on various properties of hydrogen, LNG and methane. We have experienced that finding reliable data on the properties of

hydrogen and LNG is often a difficult task. The paper therefore contributes to making such data and references easier accessible. The objective has been to present an overview of data and use these as a basis for discussing the advantages and disadvantages of LH₂ and LNG maritime fuel systems. Our analyses are based on these literature data and our own experiences with design and operation of LNG systems. The work is therefore a qualitative discussion based on data from literature.

3. Physical Properties of LNG and Hydrogen

An illustration of a phase diagram of a typical natural gas (NG) is shown in Figure 1, based on data from [9]. As illustrated in the figure, natural gas can be in the gas, liquid or two-phase state, depending on the temperature and pressure conditions. LNG is natural gas that has been cooled down until it liquefies at atmospheric pressure [10]. The origin of natural gas is reservoir fluids. Since the composition of reservoir fluids varies from field to field, the composition of the resulting processed natural gas and LNG also varies [10]. LNG therefore has methane contents varying from 87 to 99 mol% around the world [10]. Some of the properties of common LNG qualities and for hydrogen are summarized in Table 1. In the table, flammability data are given for methane (CH₄), which is the major constituent of LNG.

Table 1. Overview of selected properties of liquefied natural gas (LNG), natural gas (NG), liquefied hydrogen (LH₂) and compressed hydrogen (CH₂) with references. Data for methane (CH₄) has been added where reliable LNG/NG data could not be found.

Property	Dimension	LNG/NG	LH ₂ /H ₂	Ref. LNG/NG	Ref. LH ₂ /H ₂
Mol. weight	g/mol	16.5–18.9	2.0	[11]	[12]
Density	kg/m ³	450 (LNG)	71	[13–15]	[16]
Vapor density at standard cond. (1 atm., 15 °C)	kg/Sm ³	0.7–0.9	(0.08) ¹	[17]	[16]
Vapor density at normal cond. (1 atm., 0 °C)	kg/Nm ³	(0.7–0.9) ²	0.08	[17]	[16]
Vapor density at 200 bar	kg/m ³	182	N/A	[18]	
Vapor density at 250 bar	kg/m ³	215	N/A	[17]	
Vapor density at 350 bar	kg/m ³	N/A	23		[19]
Vapor density at 700 bar	kg/m ³	N/A	38		[19]
Boiling temperature LNG, 1 atm.	°C	−163/−161	−253	[2]/[13]	[12]
Liquid phase temperature at 1–10 bar	°C	−163 to −130	−253 to −240	[9]	[20]
ΔT in processing equipment (Amb. temp. 17 °C)	°C	180	270	[9]	[20]
Energy content of liquefied gas ³	GJ/m ³	(23–24)	(9–10)	[13,21]	[16,22]
Higher heating value	MJ/kg	54	142	[13,21]	[22]
Lower heating value	MJ/kg	50	120	[13]	[22]
Higher heating value of gas	MJ/Nm ³	43	13	[23]	[16,22]
Lower heating value of gas	MJ/Nm ³	39	11	[23]	[16,22]
Heat capacity at constant pressure	kJ/kgK	2.09	14.3	[23]	[24]
Heat capacity at constant volume	kJ/kgK	1.61	10.2	[23]	[25]
Heat of vaporization	kJ/kg	502–508/500 (LNG/CH ₄)	451	[12,26]	[27]
Lower flammability limit in air (LFL)	%	5 (CH ₄)	4	[14]	[28]
Upper flammability limit in air (UFL)	%	15 (CH ₄)	75	[14]	[28]
Minimum ignition energy	mJ	0.28 (CH ₄)	0.02	[29]	[29]
Auto-ignition temperature	°C	599 (CH ₄)	560	[14]	[28]
Maximum laminar flame speed in air	m/s	0.374	2.933	[30]	[30]

¹ Calculated based on value for kg/Nm³ [16]. ² Calculated based on value for kg/Sm³ [17]. ³ Calculated based on referenced data on density, upper and lower gravimetric heating values [13,16,21,22].

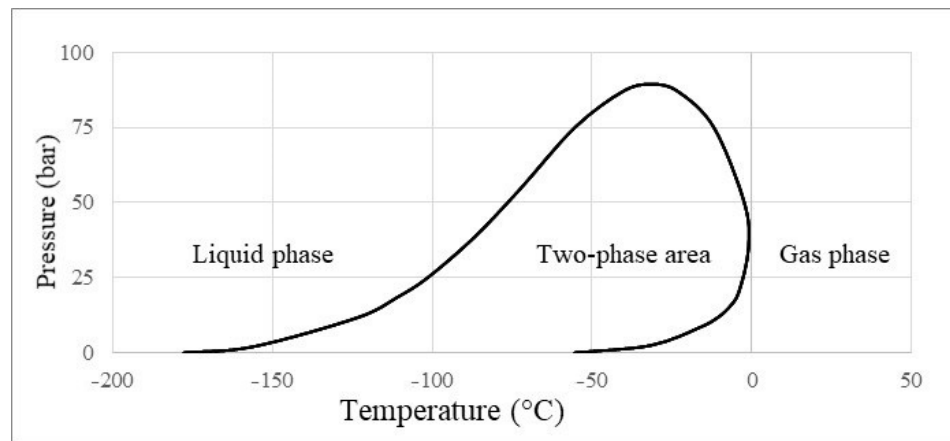


Figure 1. Illustration of a phase diagram of a typical natural gas. The diagram shows the pressure (bar) as a function of temperature (°C) of a typical natural gas. To the left in the diagram the gas is liquefied (LNG), in the two-phase area gas and liquid coexist, and to the right in the diagram only gas phase exists. Data are based on [9].

4. Energy Density and Fuel Storage Conditions

On a ship the space available for fuel storage may be limited. The volumetric energy density of the stored fuel is therefore an important parameter. Based on the data in Table 1, LNG has a volumetric energy density that is approximately 2.5 times greater than for LH₂. With CH₂ the difference in energy density is even higher. This makes CH₂ less suitable for long range vessels than LH₂. This paper will therefore focus on LH₂ as an alternative to LNG for this ship segment.

Both LNG and LH₂ are cryogenic substances and are stored at very low temperatures and low pressure, i.e., below 10 bar. The liquid/gas properties of LNG and LH₂ are illustrated in Figure 2 over a limited pressure range of 1–10 bar. LNG data are based on [9] and LH₂ data are based on [20]. The diagram shows the area of liquid hydrogen between −253 °C and the black solid line, and the liquefied natural gas (LNG) region to the left of the curved dotted line. Hydrogen in liquid phase exists only in the temperature interval between −253 °C and −240 °C [31].

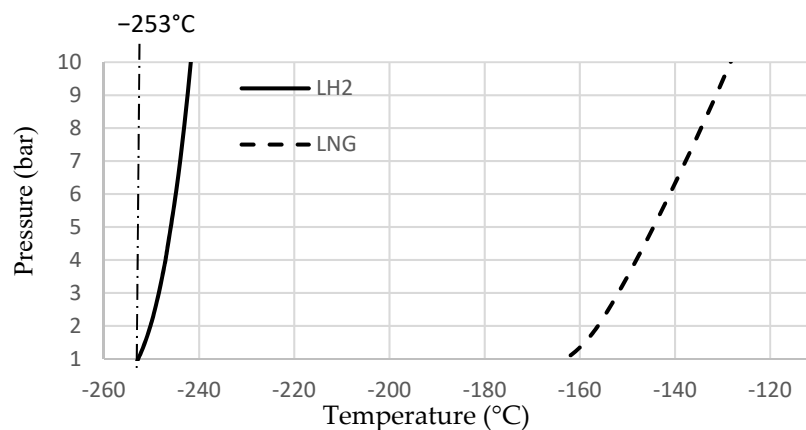


Figure 2. The figure shows the phase diagrams of liquefied hydrogen (LH₂) and liquefied natural gas (LNG) in the pressure range 1–10 bar as a function of temperature (°C). LNG data are based on [9] and LH₂ data are based on [20].

5. Existing Maritime Gas Fuel Systems Design

Maritime gas fuel systems may be LNG gas-only, or a combination of several fuel systems, e.g., dual fuel systems [32]. This paper will focus on gas-only systems. A typical maritime LNG gas-only fuel system consists of the main components shown in Figure 3 [33].

LNG for fueling the engine is supplied from the liquid phase of the LNG storage tank, evaporated in the main evaporator, and finally the evaporated gas is heated in the superheater to a temperature range in accordance with the specifications of the gas engine. For low pressure systems the minimum fuel gas pressure is typically in the range 3.5–5.3 barg [34], or ca. 4.5–6.3 bara.

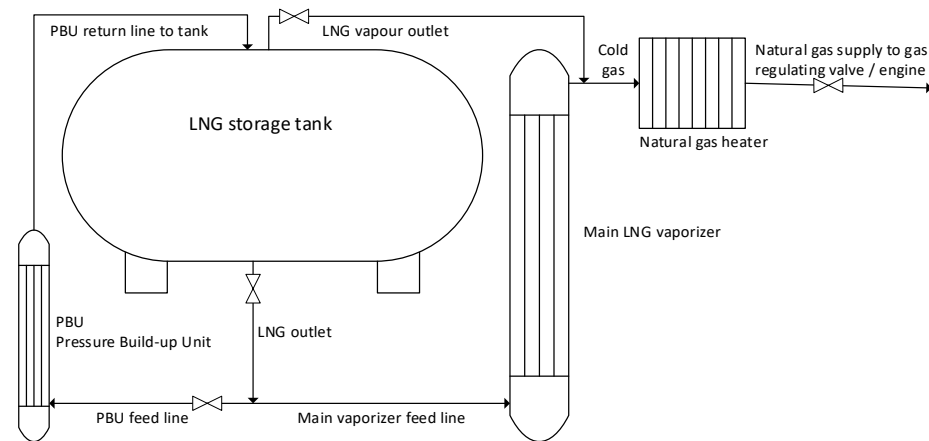


Figure 3. The figure shows a typical liquefied natural gas (LNG) fuel system with a low pressure (<10 bar) LNG storage tank, main vaporizer, gas heater and pressure build-up unit (PBU). An example of a system including an LNG pump is given in [35].

In order to supply the engine with gas at sufficient pressure the LNG storage tank is kept above the required minimum operating pressure of the gas engine. This pressurization of the LNG storage tank is obtained by withdrawing a small amount of LNG from the bottom of the tank, vaporizing/heating it through a separate pressure build-up unit (PBU) and returning the evaporated LNG to the top of the tank as natural gas in vapor state. Hence, the gas phase is at a higher temperature than the liquid phase in the tank. The gas phase is superheated. Since the driving force in this system is gravity only, this type of LNG fuel system is often called a gravity fed system.

During the bunkering process the LNG tank onboard the vessel is loaded with LNG from an LNG production and/or storage facility at $-163\text{ }^{\circ}\text{C}$ and atmospheric pressure [2]. During this transfer process the LNG may absorb heat from the surroundings through pipe walls and valves. Hence, the temperature of the LNG in the fuel tank will be slightly higher than $-163\text{ }^{\circ}\text{C}$, depending on the insulation and bunkering process. If the temperature of the LNG in the tank onboard the ship is below ca. $-145\text{ }^{\circ}\text{C}$ the corresponding vapor pressure is below 4.5 bara, which is a typical minimum pressure required for the engine [9,34].

If sloshing occurs in the tank at these conditions, the “artificial” over-pressure obtained by using the PBU may be partly or totally lost due to condensation. The cold liquid LNG will be sloshing and spraying into the gas phase, thereby cooling the gas down to the temperature of the LNG. As the gas is cooled down it will start to condensate, and the resulting pressure will drop down to the vapor pressure of the LNG at the given LNG temperature [33,36]. If this pressure is below the minimum required supply pressure required for the engine, the gas engine may shut down.

As compared to static conditions, sloshing in the tank will in general increase the heat and mass transfer between the liquid and vapor phases. The result is an increased energy absorption in the liquid phase. This leads to a higher LNG temperature and a higher vapor pressure, i.e., a higher boil-off rate [37]. However, this increased boil-off is still a slow process and is therefore not sufficient to maintain the operating pressure in the tank at all conditions. Hence, immediately after bunkering, the consequences of sloshing may be a pressure drop below the minimum required supply pressure to the engine. In the long term, as the LNG absorbs heat, the consequences of sloshing may cause a vapor pressure that is too high as compared to the maximum allowable pressure in the tank.

In order to guarantee safe supply of gas to the engine at all weather conditions, LNG fuel systems may include an LNG pump [35]. Other means to reduce the impact of sloshing are installation of bulkheads inside the storage tank. Such bulkheads are characterized both by their localization in the tank and the design of the bulkhead surface [36,38]. With unsuccessful design of the tank and bulkheads the sloshing impact may be worsened, as described by Grotle [36]. Injection of nitrogen (N₂) to the gas phase could stabilize the pressure in an LNG tank [39] but would not work in an LH₂ tank since liquid hydrogen is colder than N₂. An example of a dual fuel system is being developed for a hydrogen tug project [40].

Due to safety measures, and the fuel storage and processing plant itself, LNG systems have been costlier to install than traditional fuel systems [41,42]. They also require more space and are more complicated to operate than the traditional fuel systems. Partly because of the new regulations regarding emission limits, ship owners still choose to install LNG fuel systems. To the authors' knowledge, there have not been any serious accidents related to maritime LNG fuel systems.

6. Energy Conversion from LH₂ and LNG

Both natural gas and hydrogen may be combusted in a direct combustion engine or by using a fuel cell [29,40–42]. An LNG fuel cell was installed in the Eidesvik vessel “Viking Lady” in 2009 [43]. During a 15-year test and development program this project contributed to the qualification of fuel cell technology on vessels. However, at present internal combustion engines are the most common method for energy conversion from natural gas, and fuel cells are the most common in hydrogen systems. There are several types of fuel cells available today [44]. The main difference between them is the fuel composition, type of electrolyte used, and the ion transporting the charge inside the cell. Some of the various types of fuel cells are listed in Table 2, together with information about operating pressures and energy efficiencies.

Table 2. Overview of fuel cell technologies with preferred fuels and operating conditions. Data from references as specified in the table.

Abbrev.	Fuel Cell Technology	Fuel	Operating Temp. (°C)	Operating Pressure Range of H ₂	Efficiency ¹ (%)
PEMFC	Proton Exchange Membrane Fuel Cell	H ₂ (g) [44]	50–70 [45]	1–4 atm. [45,46]	40–60 [47]
DMFC	Direct Methanol Fuel Cell	Methanol [44]	0–80 [44]	1 atm. [48]	35–40 [47]
SOFC	Solid Oxide Fuel Cell	Pure H ₂ or hydrogen-rich fluid [44]	600–900 [44]	1–8 bar [49]	45–55 [47]
AFC	Alkaline Fuel Cell	H ₂ (g) [44]	40–150 [50]	1–4 atm. [50]	45–60 [47]
PAFC	Phosphoric Acid Fuel Cell	H ₂ (g) [44]	160–220 [51]	0–4 atm. [51]	35–45 [47]
PBI	Polybenzimidazole Fuel Cell	H ₂ (g) [44]	120–180 [52]	1–3 atm. [52]	-
MCFC	Molten carbonate fuel cell	Pure H ₂ or hydrogen-rich fluid [44]	650 [53]	1–2 bar [53]	45–60 [47]

¹ According to [47] these values are approximate numbers from literature and must be treated with caution. The data is only used for comparison of the performance of the different systems.

Research literature on efficiency and operating pressure of fuel cells is limited. However, the available literature indicates that the efficiency of a given fuel cell increases with pressure [45–52]. For both LNG and hydrogen fuel cells the average energy efficiency is 50% [32]. The average energy efficiency of comparable LNG and dual fuel combustion engines varies from 45% to 50% depending engine technology [32]. Hydrogen combustion is quite challenging both in internal combustion engines and gas turbines [29]. The magnitude of the flame velocity and low ignition energy causes combustion instabilities and require special combustion chamber and fuel injector design, as well as special safety arrangements [54,55]. Example data on the energy efficiency of the hydrogen internal

combustion engines are limited, but average values have been indicated to be around 42% [32].

The first combustion engine using hydrogen as a fuel was invented in 1806 by Isaac de Rivaz [56]. Since then, several efforts have been made to develop a safe, efficient, and cost competitive engine, but the technology is not fully developed yet. Combustion engines burn an air/hydrogen mixture, and the products of the combustion process therefore also includes NO_x in addition to water and power. The amount of NO_x produced is greatly reduced as compared with emissions from a gasoline engine [57].

Other alternatives are to use a dual fuel engine or gas turbine, or to blend hydrogen into natural gas. In hydrogen-enriched natural gas (HENG), the content of hydrogen is typically up to 20 vol% [58]. Other hydrogen energy conversion systems have been proposed, e.g., including a gas turbine or a steam turbine [52].

7. Discussion

This section gives an evaluation of the applicability of LH₂ as a maritime fuel, based on the properties of LH₂ and LNG. The discussion focuses on the challenges related to LH₂ and LNG with fuel system conditions as described previously. Our results are summarized in Table 3.

Hydrogen and natural gas are both non-toxic, colorless, and odorless gases [1,13,59]. Due to the small molecular size of hydrogen it is more difficult to seal connections and valves for leakages in an LH₂ system than in an LNG system [60].

Furthermore, the LH₂ temperature at atmospheric pressure is 90 °C lower than LNG [2,12] (ref. Table 1). In an LH₂ system, processing equipment will be subject to large temperature variations. The temperature of materials may change from −253 °C to ambient temperature, giving a temperature difference (ΔT) of around 270 °C. In an LNG system, the equivalent ΔT is around 180 °C. As a result of the temperature fluctuations, material contraction and expansion may lead to fatigue and leakages. Moreover, hydrogen is highly reactive, which can lead to degradation of the material and consequently leakage [59]. Hydrogen embrittlement can reduce the tensile strength, ductility, fracture toughness and crack behavior of metals [16]. In an LH₂ system the risk of leakages is therefore probably greater than in an LNG system. This implies stricter material requirements in LH₂ systems as compared to LNG systems.

Compared to methane, hydrogen is flammable over a wide mixing range with air [14,28] (ref. Table 1). Methane has a flammability range in air of 5 to 15% by volume, while for hydrogen the flammability range is from 4 to 74% by volume. Moreover, hydrogen has a lower ignition energy of 0.02 mJ as compared to 0.28 mJ for methane [29]. Also, due to the low electroconductivity of hydrogen, flow or agitation of hydrogen gas or liquid may generate electrostatic charges that could result in sparks and thereby causing ignition [60]. Together, these properties make hydrogen more easily ignited than methane.

Laboratory experiments indicate that the flame propagation speed of hydrogen is higher than for methane, and that a hydrogen/air explosion would be more intense than a methane/air explosion, both with respect to explosion pressure and pressure fluctuation [61]. If a hydrogen leakage is ignited, it could burn with a flame speed 10 times faster than for hydrocarbons [58]. Since hydrogen has a much larger flammability range and lower ignition temperature than LNG, this is a major concern related to maritime hydrogen systems. This is especially important when designing the relief valve and flare system.

Both hydrogen (in gas phase) and natural gas are lighter than air, as shown in Table 1 [16,17]. This means that in case of a leakage, the gas will rapidly rise and be diluted, thereby reducing the risk of accidental ignition and burning. Simulation studies show that the dilution distances of subcooled LH₂ leaks were significantly longer than for saturated vapor leaks [62]. The reason is that leakages from subcooled LH₂ will result in a mixture of gas and liquid phases at the leakage point. I.e. they are denser than a saturated vapor leakage and therefore need a longer distance to be diluted in air. Also, this dense

two-phase mixture was found to be heavier than air [62]. Similar phenomena have been described in relation to LNG leakages [15,61].

In case of pipeline rupture with large leakages of LNG or LH₂, a boiling liquid “pool” may form on the ground. The temperature above the boiling liquid “pool” of LNG or LH₂ will be very cold, and the vapor may have a high density/dense phase behavior [62–64]. The gas will therefore probably be diluted much more slowly than from leakages from their respective gas phases [60,62,65]. If LNG or LH₂ leaks out at an elevated location onboard the ship, there may therefore be a risk that the vapor moves downwards to the ship instead of upwards in the air. Hence, the vapor cloud may return to ship areas where there are potential sources of ignition. Because of the wider flammability range and lower ignition energy of hydrogen [14,28,29], this constitutes a greater risk in an LH₂ system than in an LNG system. Furthermore, this means that a leakage from a pipe with LH₂ represents a significantly higher risk than a leakage from a pipe with gaseous hydrogen or natural gas.

As calculated and shown in Table 1, the energy content is 23–24 GJ/m³ in LNG and 9–10 GJ/m³ in LH₂, respectively. Hence, the volumetric energy density of LH₂ is less than half of that of LNG, which means that the LH₂ fluid itself would occupy more space on board the ship than the same energy content stored as LNG.

The space allocation of current fuel cell installations is twice the volume allocated by a traditional combustion engine [66]. If the added volume of the storage tank, as well as the increased weight and costs of the storage tank, insulation and double piping are included, the picture will be even worse for LH₂.

If the fuel cell or combustion engine requires a minimum gas supply pressure (ref. Table 2), the type of components in the processing system will be almost identical for LNG and LH₂. The reason is that both fuels have the same challenges regarding pressure drop due to sloshing in periods just after bunkering, as previously discussed.

For both fuels, the problem with pressure drop can be solved by either using a dual fuel engine, installing a cryogenic pump, or with careful design of the tank length/diameter-ratio and installation of special designed bulkheads.

The cryogenic fuel storage tank (type C independent tank) is basically a big thermos with no active cooling of the fluid inside [2]. With LNG or LH₂ in a storage tank, the temperature inside the tank will be lower than the temperature of the surroundings outside the tank. Although the tank is insulated, there will be some heat conduction from the surroundings into the tank, resulting in a slow heating of the cold liquid [67].

As the temperature of the fluid in the tank increases, the pressure will increase (ref. Figure 2). If the pressure approaches the maximum design pressure of the tank, the relief valves will open and release gas to the atmosphere. Gas release to the atmosphere is unacceptable from an LNG tank, due to the high GWP of 25 over 100 years for natural gas [18]. Hydrogen is an indirect greenhouse gas with a GWP of 5.8 over 100 years [68]. Although hydrogen has a lower GWP than LNG, it still would have a negative impact on the climate. Also, relief of gas from an LH₂ tank has a greater risk of ignition and fire or explosion. Moreover, it is not desirable in view of the large investment costs in producing the hydrogen and cooling it down.

While fuel is consumed from the tank the pressure will normally not build up [2]. Pressure build-up may be a challenge if there are longer periods without consumption from the tank [2]. The pressure build-up rate depends on the tank design, processing system design and movements of the tank (weather conditions) [37]. Therefore, in both LH₂ and LNG fuel systems, the storage tank dimensions must be optimized with respect to sailing range, bunkering frequency, and operational profile to avoid reaching the maximum pressure limit of the tank.

The heat conduction from the surroundings and into the fuel storage tank is governed by Fourier’s law, as described in [67]. According to this law, the heat flux is proportional to the thermal conductivity, the area of the outer surface of the tank, and the temperature gradient. For storing the same amount of energy as LNG, LH₂ would require approximately twice the volume of the LNG tank, i.e., a larger area of the outer tank surface. Also, the

temperature gradient from outside to inside of the tank will be 90 °C higher. With identical insulation, this means that the heat flux into an LH₂ tank will be greater than the heat flux into a comparable LNG tank. If the heat capacity and the mass of LH₂ and LNG in the tanks are taken into account, the resulting temperature increase rate in the tanks will be in the same range. More thorough simulations are needed to investigate the effect of the heat flux in detail.

However, even if the temperature increase-rate of an LH₂ and LNG tank will be in the same range, it is important to note that the resulting effect on the vapor pressure is greater in an LH₂ system, as shown in Figure 2. According to Figure 2, the pressure in an LNG tank increases less per °C than in an LH₂ tank. In fact, the temperature in the LNG tank could be allowed to increase by more than 30 °C before the pressure reaches the maximum tank design pressure of 10 bar [9]. In comparison, the LH₂ temperature can only be allowed to increase by 13 °C before reaching the 10 bar pressure limit [20].

Hydrogen exists in liquid phase only in the temperature interval between −253 °C and −240 °C [31]. Hence, LH₂ must be maintained within this temperature range of $\Delta T = 13$ °C throughout the distribution chain. Preventing heating during reloading and storage along the value chain is therefore even more important for LH₂ than for LNG. LNG is easier to handle than LH₂, since it can be maintained in liquid phase and below a pressure of 10 bar over a temperature range of 30 °C.

The tank operational properties must comply with the requirements of 15 days holding time, as stated by the IGF code [2]. It is therefore important to build LH₂ tanks with considerably more efficient insulation than in comparable LNG tanks. An overview of the most common (passive) insulation methods for LNG tanks and the resulting thermal conductivity is given in [67,69]. Another solution would be to design a storage tank with an active cooling system [70].

The above described challenges with heat conduction from the surroundings can be limited but not eliminated. For these reasons, the energy supply chains for both LNG and LH₂ supply must be customized according to the consumer demand. In this way, it is possible to limit the storage time, thereby reducing the risk of pressure build up and avoiding gas release to the atmosphere. Due to the extremely low temperature of LH₂ as compared to LNG, and the smaller temperature interval of liquid phase with pressure below 10 bar, this challenge is greater for LH₂ than for LNG systems. This is probably one of the major challenges with LH₂ with respect to implementation as a fuel in maritime industry. Infrastructure with proper pre-cooling facilities is crucial, to minimize the heat leak during pipe transfer and reloading. It is also important to reduce the number of re-loadings along the supply chain, and to minimize the transport time (distance) from producer to consumer.

In LNG systems, nitrogen is usually used for purging and cooling, since it is an inert gas that is colder than LNG. Liquid nitrogen (LN₂) has a boiling temperature of −196 °C at atmospheric pressure [1], i.e., below the boiling point of LNG of −163 °C as given in Table 1 [2]. LN₂ therefore works well for inerting and pre-cooling pipelines before starting the transfer of LNG [67]. LH₂ has a boiling point of −253 °C at atmospheric pressure and is colder than LN₂, so LN₂ is not as well suited for cooling a LH₂ system as in an LNG system. Hence, LN₂ works as a tool for inerting the pipeline before LH₂ transfer but is less efficient in pre-cooling it. Instead, helium gas with boiling point at −296 °C may be used for inerting and cooling in LH₂ systems [70].

Onboard LNG fueled ships, gas sensors must be installed near locations where there are higher risks of leakages, and/or higher consequences of leakages, in accordance with the requirements of the IGF Code [71]. Because of the wider flammability range and the lower ignition energy (ref. Table 1), a leakage of hydrogen will most likely constitute a higher risk and more serious consequences than a leakage of LNG. Double barriers must therefore be a requirement in hydrogen systems, in combination with other safety means, e.g., double piping. In double piping systems, the fuel gas is contained in the inner pipe, while the space between the concentric pipes may be pressurized with an inert gas at a

higher pressure than the fuel gas in the inner pipe [71]. Other means of reducing the risks are adding sensors and enhancing the ventilation or using inert atmosphere in the tank connection space [71]. Localization of the LH₂ tank on open deck could be advantageous with respect to ventilation conditions and reduced risk of entrapment of flammable gas clouds. However, on open deck the risk of damage to the LH₂ tank and subsequent leakage would be higher.

Table 3. The table shows a summary of the discussion of the applicability of liquefied hydrogen (LH₂) as a maritime fuel. In the table, LH₂ is compared to liquefied natural gas (LNG) as a maritime fuel. Only properties where LH₂ and LNG show significant differences are listed here. (“0”: The challenges are similar for LH₂ and LNG systems. “÷”: The given characteristics constitutes a disadvantage for LH₂ systems as compared to LNG systems. “+”: The given characteristics constitutes an advantage for LH₂ systems as compared to LNG systems).

Property	LH ₂ vs. LNG	Comment
Molecular size	÷	Smaller molecular size than methane. More difficult to avoid leaks [60].
Temperature at 1 atm.	÷	−253 °C for LH ₂ vs. −163 °C for LNG [2,12]. Requires more efficient insulation. Higher risk of embrittlement. Requires higher material quality in pipes.
Liquid phase temperature interval at 1–10 bar pressure	÷	ΔT = 13 °C for LH ₂ vs. ΔT = 30 °C for LNG [9,20]. Requires more efficient control of heat leak during reloading, transport and storage.
ΔT in processing equipment (Ambient temp. 17 °C)	÷	ΔT = 270 °C for LH ₂ vs. ΔT = 180 °C for LNG. Higher risk of fatigue and embrittlement. Requires higher material quality.
Reactivity	÷	Higher reactivity. Requires higher material quality [16,59]
Dense phase behavior of leakages	0	Similar to LNG systems [61,62]. Risk of gas with negative buoyancy returning to ship areas and potential ignition sources.
Energy content of liquid phase	÷	Lower volumetric energy content (ref. Table 1). Requires bigger fuel storage tank onboard the ship.
Heat capacity	+	Higher heat capacities [16,23]. Requires more energy to heat 1 kg gas 1 °C. Advantageous wrt. heating rate during storage.
Heat of vaporization	(÷)	Slightly lower than for LNG in kJ/kg [26,27].
Heat flux from surroundings and into the tank	÷	Higher heat flux, if the insulation used is similar to what is used in LNG tanks.
Flammability range in air	÷	Wider, i.e., flammable conditions are more easily formed [14,28]. Higher risk of fire and/or explosion.
Ignition energy	÷	Low, i.e., more easily ignited than LNG [29].
Auto-ignition temperature	(÷)	Slightly lower than methane [13,28].
Maximum laminar flame speed in air	÷	Higher than for natural gas [22]. Greater risk of spreading of fire.
Space allocation of fuel cell	÷	Space allocation of fuel cell is twice the volume of combustion engines [66].
Pressure drop due to sloshing in tank	0	Similar to LNG systems.
Purging and cooling of equipment	0	Helium can be used instead of nitrogen [70].
Global Warming Potential (GWP)	+	5.8 vs. 25 over 100 years [68]. Less damaging for the climate in case of leakage to the atmosphere.
Training of operating personnel	0	Required for both LH ₂ and LNG systems.
Availability as maritime fuel	÷	Supply chain of LH ₂ as maritime fuel is not established. Supply chains for LNG are well established in some regions [2].

A recent concept risk analysis of a high-speed passenger ferry powered by CH₂ concluded that the risk related to the compressed hydrogen system is within acceptable risk tolerance level [72]. Similar analyses must be performed on LH₂ systems, since these systems have considerably more safety challenges than CH₂, as discussed above. Based on such risk analyses, requirements for double piping, ventilation and location of sensors may

be described. Finally, the total costs of the system will be crucial for the decision of the ship owner to choose LH₂ as a fuel. A study of the feasibility and commercial considerations of LNG fueled ships have been published by [73]. The costs must be competitive to the costs of LNG systems, including emission taxes. Other important factors in the decision process is the potential loss of cargo space, uncertainties related to bunkering infrastructure and fuel availability [73].

Finally, one of the most important factors regarding safety is the operating personnel. They need to be trained, so that they know the system, the potential risks, and the mitigation procedures. Operating procedures and safety routines must be developed. The personnel must be aware of the differences between systems for traditional fuels and hydrogen and must wear protective gear according to the actual operation activity.

8. Conclusions

In this paper, an evaluation of LH₂ and LNG as maritime fuels has been given. Although LH₂ is a cryogenic fuel like LNG, transferring from LNG to LH₂ as a maritime fuel is not straightforward. Some of the experiences with LNG are transferable to LH₂ maritime systems. Basically, the fuel processing systems of LNG and LH₂ will contain similar main components. However, LH₂ is an even more challenging fuel than LNG when it comes to safety, storage time, supply chain and space onboard the ship. This is due to the low temperature, higher risk of leakages, wider flammability range, lower ignition energy, sensitivity to heat leak and lower volumetric density.

Significantly higher safety restrictions must be applied for LH₂ fueled maritime systems than for LNG systems. IMO, IGF and Class societies' rules and regulations need to be adapted accordingly. Mitigation measures must include double piping, inert gas systems and ventilation, detectors, and safety procedures. Optimal placement of the LH₂ storage tank onboard the ship must be identified through risk analyses. The analyses must evaluate the risk of leakages and entrapment of flammable gas mixtures versus risk of external damage of the tank. This includes analyses of probable diffusion distances, dilution rates of gas leakages and possible ignition sources. As a result of the regulatory framework [69], present LNG systems onboard ships are designed to be able to handle potential leakages. In an LH₂ fueled ship, risk of leakages cannot be accepted. Based on our analyses, the main challenges for implementing LH₂ as a maritime fuel are:

- How can LH₂ be maintained at low temperature, with a minimum of heat loss and a minimum of pressure increase? What are the implications for tank design, insulation and active cooling methods?
- What are the safety implications regarding tank localization onboard the ship?
- How can the relief valve and flare system be designed and localized to minimize the risk of fire and explosion?
- What are the material, system and design requirements for the piping and processing system?
- What are the total costs per kWh at propeller, as compared to other renewable or low carbon energy carriers?
- How to develop procedures for personnel handling LH₂ in maritime fuel systems? Procedures must be developed for safe handling of LH₂ during transport, distribution, transfer, bunkering, storage, and consumption on board the ship.

When it comes to investments on-board the ship, LH₂ systems will probably be costlier than today's LNG systems. The number of main components in the fuel system may not be very different, but LH₂ will require higher material quality, extensive use of double piping and sensors.

The availability of LH₂ is still limited. There are plans for hydrogen production plants and hydrogen distribution networks, but the availability is still too limited for it to be a commercial alternative fuel. According to the European Commission 96% of hydrogen available today comes from fossil fuels [74]. Renewable hydrogen can be produced from electrolysis of water using wind and solar energy as power sources. However, this will

require cost reductions in electrolyser technologies, which are not expected to be fully mature until 2030 the earliest. Whichever production method is used, the CO₂ emission from transport of the hydrogen from the production plant to the end user must be included in the evaluation.

As compared to LNG, LH₂ has a more limited storage time. It is therefore important to produce LH₂ as close as possible to the consumer and to reduce the number of re-loading operations. Hence, LH₂ may not be suited for global trade in the same extent as LNG. For maritime application, it would be advantageous to supply LH₂ from a local or short-range value chain. This would reduce the intermediate storage time in transportation and the CO₂ emission related to transport.

For hydrogen to become a realistic alternative as a maritime fuel, pilot projects must be able to demonstrate that LH₂ systems are at least as safe as LNG systems. Furthermore, supply chains for hydrogen produced from renewable energy must be established. Control and logistics of the LH₂ supply chain is even more critical than for LNG, due to the narrow temperature interval where hydrogen is in liquid state, and due to the higher risk of leakages. Personnel training courses and procedures for safe operation of maritime fuel systems must be developed of the relevant authorities as soon as possible.

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