Norwegian Centres of Expertise
NCE Maritime CleanTech

Norwegian future value chains for liquid hydrogen

maritimecleantech.no

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Acronyms and abbreviations

Abbreviation	**Meaning**
ADR	European Agreement concerning the International Carriage of Dangerous Goods by Road
ATR	Auto Thermal Reforming
CCS	Carbon Capture Storage
C_3H_8	Propane
CH_3OH	Methanol
CH_4	Methane
CO_2	Carbon Dioxide
CO_{2eq}	Carbon Dioxide Equivalent
FCH-JU	Fuel Cell and Hydrogen 2 Joint Undertaking
GHG	Green House Gas Emissions
GoO	Guarantee of Origin
HSC	High-Speed Craft
HVO	Hydro Treated Vegetable Oils
IEA	International Energy Agency
IEAGHG	International Energy Agency Greenhouse Gas
IRaS	Integrated Refrigeration and Storage
IRENA	The International Renewable Energy Agency
ISO	International Organization for Standardization
K	Kelvin
LH2	Liquefied Hydrogen
LNG	Liquid Natural Gas
LPG	Liquefied Petroleum Gas
MGO	Marine Gas Oil
NASA	The National Aeronautics and Space Administration
NCE	Norwegian Centres of Expertise
NH_3	Ammonia
Nm^3	Normal cubic meter
PCU	Personal Car Unit
PEM	Proton Exchange Membrane
PSV	Platform Supply Vessel
SMR	Steam Methane Reforming
SOFC	Solide Oxide Fuel Cells
USD	United States Dollar
VAT	Value Added Tax

Units

1 EJ	=	278 TWh
1 MJ	=	3,6 kWh
1 MPa	=	10 bar
1 Ton	=	1000 kg
1 TWh	=	1000 GWh

1. Summary

The purpose of the report has been to investigate barriers for a future Norwegian value chain on liquid hydrogen for maritime use, with a special focus on the volumes of LH_2 for car ferries, high-speed crafts and platform supply vessels in the region from Rogaland to Trøndelag.

The most obvious barrier is the lack of access to liquid hydrogen produced in Norway. In addition to transportation costs, the current liquefaction capacity in Europe of 20 tons per day is far from the volumes needed. If just 25 percent of the energy consumption from the three vessel types is converted to hydrogen it would require 72 tons per day, and several crossings would require a daily transportation of volumes up to four tons, making the value chain prone for logistical problems.

A complete transformation from fossil fuels to LH_2 for car ferries, high-speed crafts and PSVs would have a daily demand of about 275 tons of hydrogen. This is a volume that Norway has the energy resources to produce both through electrolysis using renewable energy and gas reformation using natural gas. Hydrogen production from natural gas needs CCS to achieve a CO_{2e}/kg LH_2-level low enough to be labelled as blue hydrogen.

In terms of storage and distribution by truck several suppliers have extensive experience with cryogenic tanks, making this the most mature component of the value chain. Today trailers can transport about 4000 kg of liquid hydrogen, while the largest on-site storage tanks developed for space industry has a volume of 3800 m^3. However, for an effective distribution of larger volumes, bunkering vessels and/or tankers must be developed for operation along the coastline.

For bunkering two different solutions, pressure-fill utilizing different pressure between the offloading and receiving tank, or assisted by a LH_2-pump, can be used. Studies show that a flow rate of 1000 kg per 20-40 minutes is achievable by pressure-fill, while submerged LH_2 pumps can increase the flowrate up to 600 m3/hour. However, there are no commercially available bunkering station available for maritime use.

Throughout the value chain, further work on regulations, standards and codes developed specifically for the maritime use of liquid hydrogen is needed.

From a price perspective LH_2 today is not competitive with other fuels. Liquid hydrogen transported from Europe to Southern Norway has a retail price of about 15 Euro/kg, making the cost of delivered kWh to the propeller more than eight times higher than for marine gas oil. But through technology development and establishment of large production and liquefaction facilities in Norway a cost in the range of 3,5-7,5 Euro/kg, making the cost per kWh competitive with bio-diesel is realistic.

2. Introduction

Through the ratification of the Paris Agreement, Norway has agreed to reduce CO_2-emissions with 40 percent in 2030 – compared to 1990-levels[1], with an increased commitment to 45 percent in the recent governmental platform. In addition, the International Maritime Organization has an ambition to reduce CO_2-emissions from the shipping sector by 50 percent – compared to 2008-levels by 2050[2].

In 2017, inland sea transport (and fisheries) were responsible for the emission of 3,0 million tons of CO_2-equivalents, or 5,6 percent of the total Norwegian emissions (including the oil and gas sector)[3]. To reduce emissions, new renewable energy carriers and powertrains must be introduced to the maritime sector.

In this study, we focus on a future Norwegian value chain for liquid hydrogen, from production of hydrogen to bunkering of three types of vessels: car ferry, high speed craft and a platform supply vessel. With the first car ferry using hydrogen to be put into traffic in 2021 and several other projects and developments involving other types of vessels, it is important to identify future market potential, technology and regulation gaps and the infrastructure necessary to support the development of such value chains.

We have included two production methods of hydrogen in our scope: gas reformation using natural gas and electrolysis using electricity and water. While there are other ways to produce hydrogen, these two are the most likely methods from a Norwegian perspective. It is also a prerequisite that hydrogen from natural gas is combined with carbon capture & storage to avoid CO_2-emissions. From production of hydrogen and subsequent liquefaction, we move our attention to storage, distribution and users.

Our geographical focus has been the Western coast of Norway from Trondheim to Egersund, covering a substantial amount of the traffic to the Norwegian oil fields in The North Sea and the Norwegian Sea, as well as car ferries and high-speed crafts.

The project has been supported financially by the Hordaland County Council and led by NCE Maritime Cleantech – a cluster organization focusing on establishing sustainable innovation projects with commercial potential and working together for new clean maritime solutions. Research and analysis are done by cluster members Greensight and Norled, with support from project partners Equinor and Gasnor.

Table 1: Project participants

Organization/company	*Name*	*Position*
NCE Maritime Cleantech	Pål G. Eide and Paul Helland	Project Manager
Greensight	Martin L. Hirth (lead author), Karoline U. Hove and Daniel Janzen	Energy analyst / Energy economist
Norled	Ivan Østvik	Project Manager Hydrogen
Equinor	Thomas Ryberg	Principal Engineer Platform Technology Ship Technology
Gasnor	Johnny Ødegård	Prosjektleder

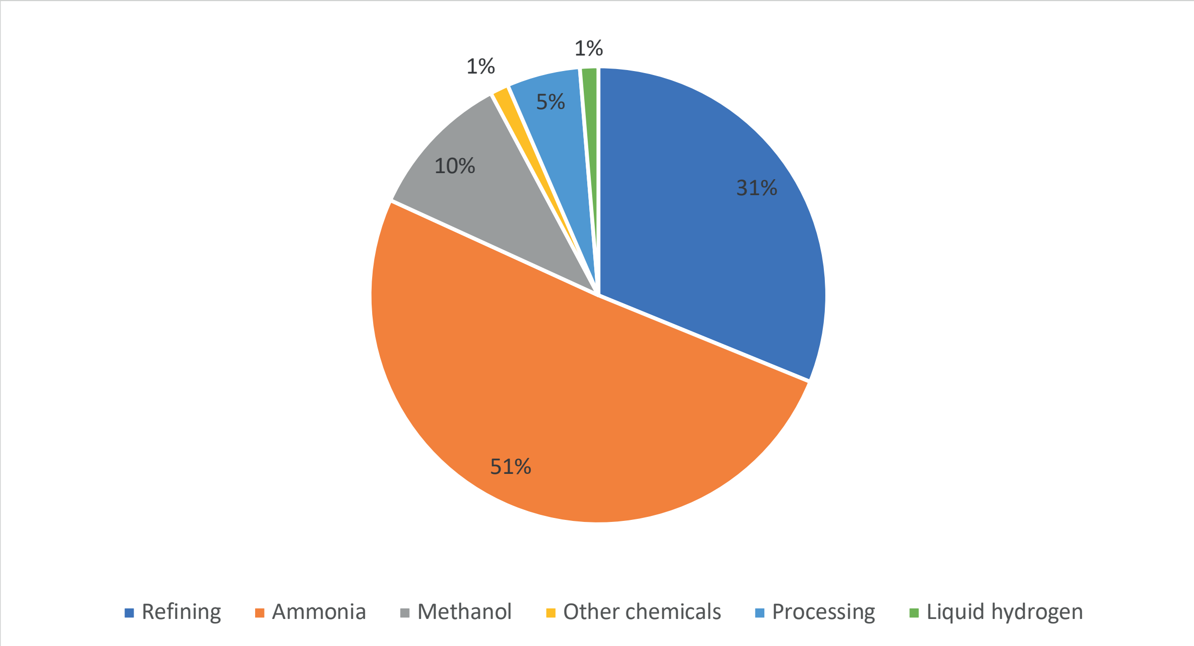
[1] Regjeringen, 2016
[2] IMO, 2018
[3] SSB, 2018b

3. Hydrogen today

Today, over 50 percent of the global production of hydrogen is used to produce ammonia for urea and other fertilizers. Of the remaining half, around 30 percent is used for various processes related to refineries and about ten percent is used for methanol production. Hydrogen for transporting purposes is merely a marginal market as of today.

In total the current demand for hydrogen is about 8 EJ of energy per year, equivalent to about 67 million tons of hydrogen[4] or 2224 TWh of electricity[5]. As we see from the figure below, around 1 percent of the global hydrogen demand today is in liquid form.

Figure 1: Global hydrogen demand by subsector



In Norway, about 225 000 tons of hydrogen is produced in industry processes. Most of this hydrogen is used to produce methanol at Tjeldbergodden at Aure in Møre og Romsdal County (Equinor) and ammonia at Herøya in Porsgrunn in Telemark county (Yara).

At Tjeldbergodden, Equinor uses about 112 500 tons of gaseous hydrogen are used per year, with an additional 5 500 tons of hydrogen being recirculated and used for heating together with natural gas. They also have an excess production capacity of about 15 tons per day[6]. At Herøya the yearly demand is about 70 000 tons of hydrogen[7]. Both facilities produce hydrogen locally by reforming natural gas, currently without CCS[8].

[4] Using the lower heating value of 33,3 kWh/kg H2
[5] Hydrogen Council (2017) and IRENA (2018)
[6] Teknisk Ukeblad (2019b)
[7] Based on a combined yearly demand of 180 000 tons between Tjeldbergodden and Herøya in (DNV-GL 2019)
[8] DNV-GL (2019)

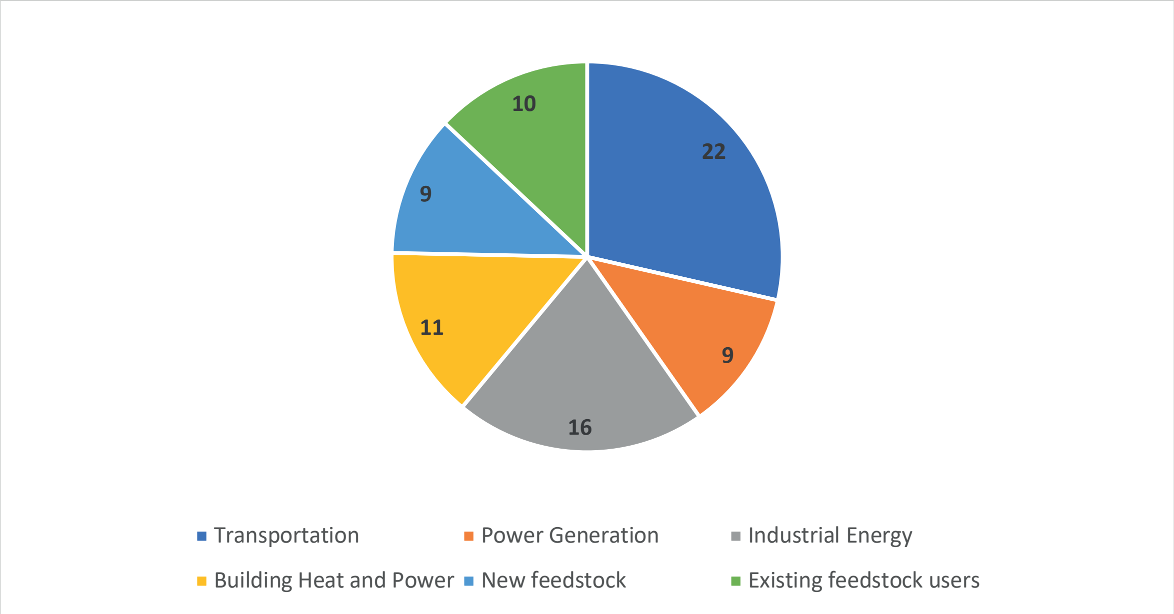
3.1 Future demand

The future global hydrogen market is dependent on both technological and political development. The International Renewable Energy Agency (IRENA) estimate an additional market demand of 8 EJ in 2050 – in addition to the current demand in feedstock[9]. The growth will come in the transportation sector.

In their Sky Scenario, Shell argues that hydrogen will emerge from 2040 and onwards, primarily for industry and transport, with a growth of about 8 EJ until 2050 and a steep increase onwards. In 2070 they estimate a growth of 35 EJ of hydrogen from today's level.

In a more optimistic scenario, the Hydrogen Council (figure 2) argue that the hydrogen market could increase tenfold to 78 EJ in 2050. While all sectors grow, transportation makes the largest leap, from next to nothing in 2019 to approximately 22 EJ or 6116 TWh of electricity.

Figure 2 – Global hydrogen market in 2050 (EJ)[10]

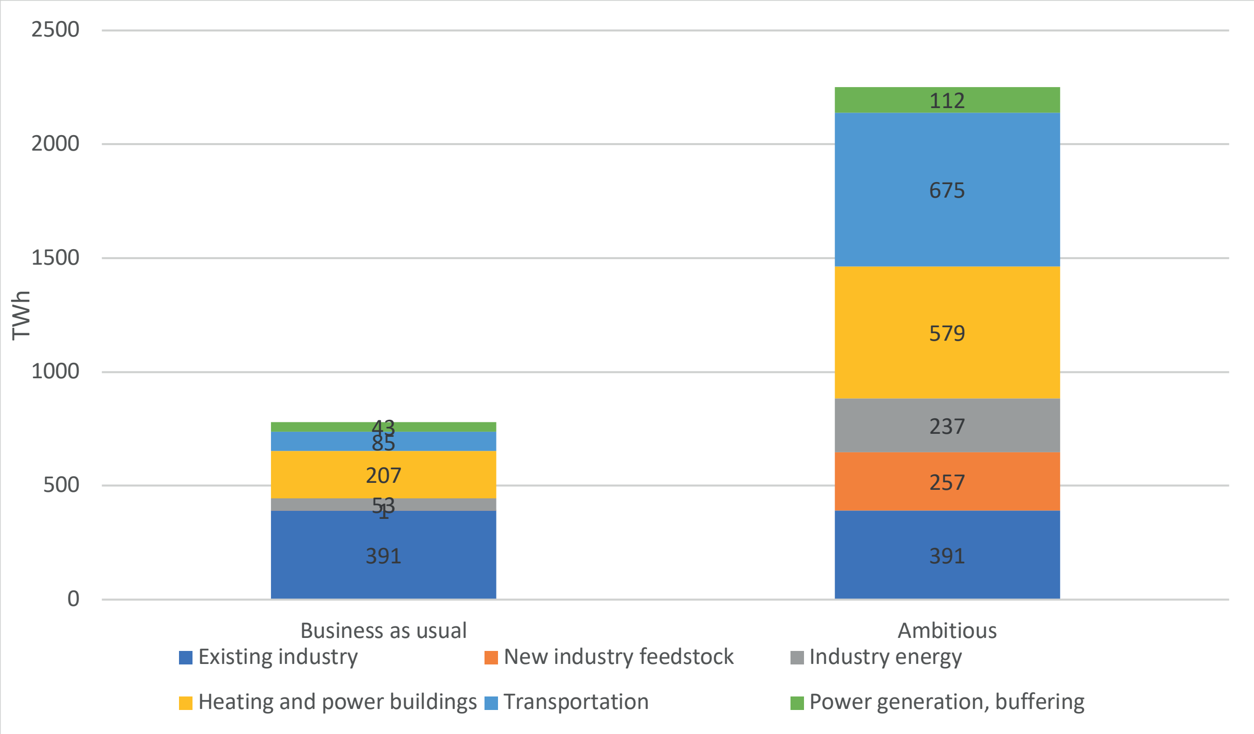


For the European Union alone Hydrogen Europe, as part of the EU-project Fuel Cell and Hydrogen 2 Joint Undertaking (FCH-JU) looks at two scenarios presented in figure 3 for future growth: «business as usual» and «ambitious». In the two scenarios hydrogen make up 8 (780 TWh) and 24 percent (2 251 TWh) of the final energy demand[11] in 2050, up from 2 percent today (325 TWh). Most of the forecasted increased market demand comes from heating and power for buildings and transportation[12].

[9] Irena (2018b)
[10] Hydrogen Council (2017)
[11] Final energy demand has removed losses from energy transmission and distribution. Thus, it represents the final amount of energy left at the disposal of households or other customers.

[12] FCH-JU (2019)

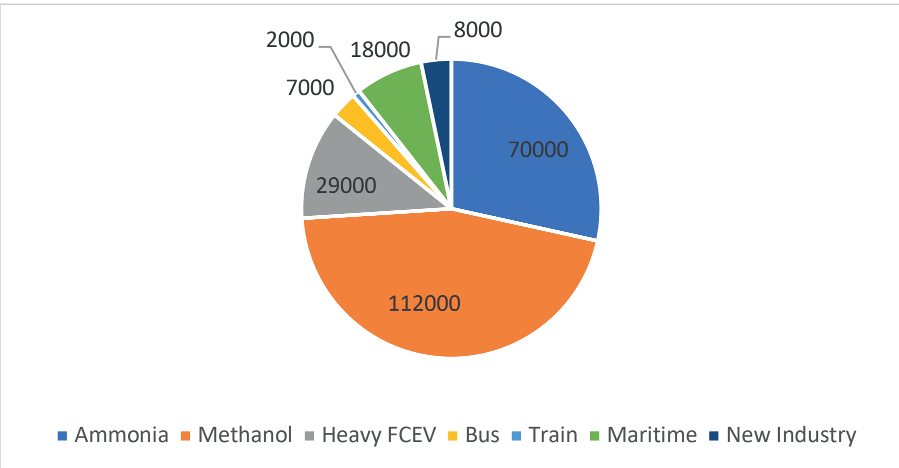
Figure 3 – European final energy demand from hydrogen in 2050 (TWh)



For a future Norwegian hydrogen demand, DNV-GL has estimated an annual demand of 225 000 tons per year. Note that while the same amount of hydrogen is produced today, a portion of the current production is a result of hydrogen being a bi-product from industrial processes without an end user. In their 2030-estimate DNV-GL are referring to a market demand.

Based on dialogue with the owners of facilities at Tjeldbergodden and Herøya they assume that their demand of hydrogen will remain stable in the coming years, thus making up about 75 percent of the annual demand in 2030.

Figure 4 – Demand of hydrogen in Norway 2030 – tons per year



The remaining 25 percent is divided between heavy duty vehicles, buses, maritime, trains and new industrial users. Demand from the maritime sector is estimated to be 18 000 tons of hydrogen per year, calculated from a list of 186 vessels that hails from the five largest ports in terms of marine refuelling today[13].

While there seems to be an agreement in different scenarios on the expansion of hydrogen, especially in the transportation sector, the literature study also shows a great variety in the estimated demand, with a high degree of uncertainty.

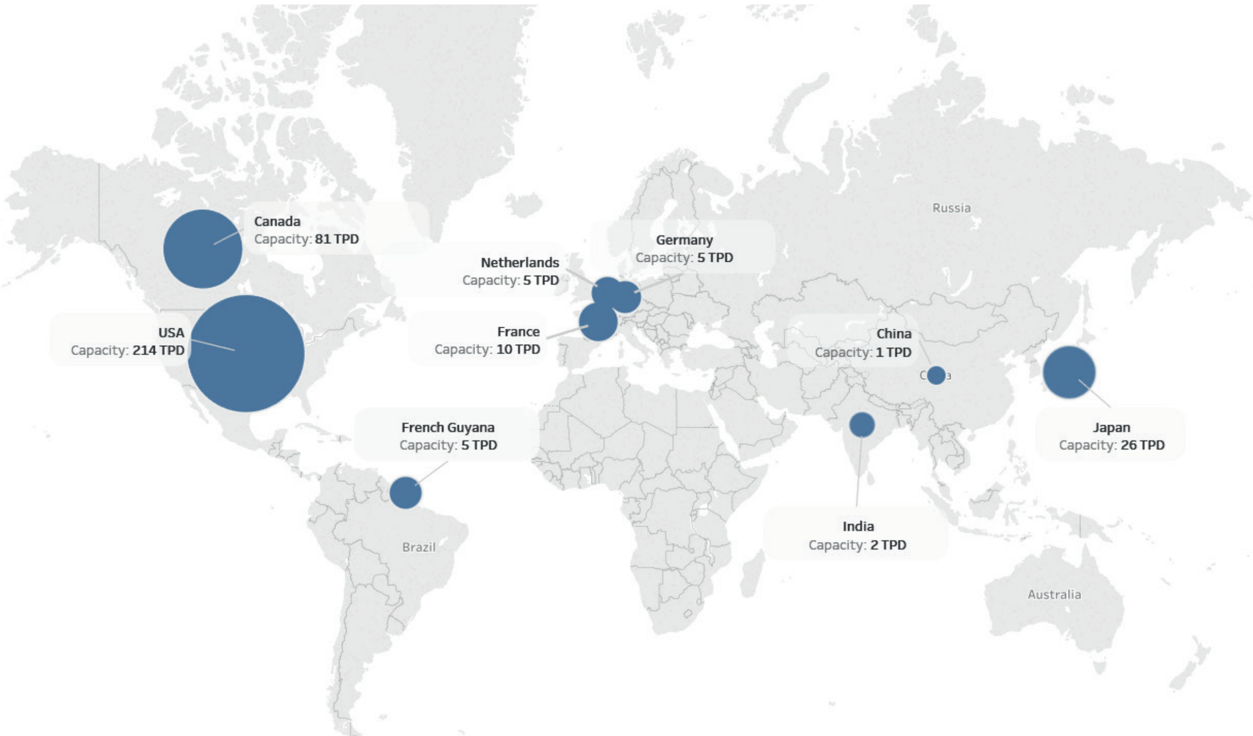
Table 2 – Summary of scenarios for future demand – TWh and EJ[14]

Source	*Geography*	*Year*	*TWh*	*EJ*
DNV-GL (2019)	Norway	2030	8,34	0,03
FCH-JU (2019)[15]	Europe (final energy demand)	2030	481/665	1,7/2,4
FCH-JU (2019)	Europe (final energy demand)	2050	780/2251	2,8/8,1
Shell Sky (2018)	Global	2050	4 726	17
Irena (2018)	Global	2050	4 448	16
Hydrogen Council (2017)	Global	2050	21 684	78

3.2 Liquid hydrogen

While there is no lack of hydrogen production worldwide, the global liquefaction capacity is about 350 tons/day. Current large-scale consumers of liquefied hydrogen are aerospace industry, chemical industries, electronic/semiconductor industry and metallurgical industries.

Figure 5 – Tons of liquid hydrogen produced per day



Most of the current production takes place on the American continent, with a roughly estimated production capacity of 215 tons/day in the USA and 81 tons/day in Canada. The

[13] Stavanger, Bergen, Ålesund, Kristiansund and Tromsø
[14] For the IRENA and Shell scenarios the estimated growth is added to the existing demand of 8 EJ
[15] For FCH-JU the «business as usual» and «ambitious» scenarios are both listed

production capacity is expected to increase, as Air Liquide[16], Air Products[17] and Praxair[18] have announced plans to build plants with a combined production of an additional 90 tons/day in the US. Behind the US and Canada, Japan is the third largest producer of liquefied hydrogen, with an estimated production capacity of 30 tons/day.

As shown in the table below – there are currently three production plants for liquid hydrogen currently in operation in Europe, with a daily production of about 20 tons per day. In October 2018 Linde announced plans to double the production capacity at their facility in Leuna, Germany to 10 tons per day from 2021, increasing the total European production to 25 tons per day[19]. All three production plants in Europe produce liquid hydrogen from natural gas by steam methane reforming, currently without CCS.

Table 3 – Current capacity of liquid hydrogen in Europe

Producer	*City*	*Country*	*Process*	*Capacity (Nm^3/day)*	*Capacity ton/day*	*Year Opened*
Air Liquide	Waziers	France	SMR	4 864	10	1987
Air Products	Rotterdam/Rosenberg	Netherlands	SMR	2 502	5	1990
Linde	Leuna	Germany	SMR	2 038	5	2007

Currently without liquefaction plants in Norway, any demand for LH_2 must be imported from Europe. From Air Products in Rotterdam liquid hydrogen can either be distributed by truck on road only with a cryogenic tank or as a cryogenic tank container at top-deck on a ro-ro vessel with road transport to and from quay. The plant in Leuna does not have excess capacity until the production is increased[20] and it has not been possible to get an estimation on the available capacity at the Air Liquide facility in France.

For a future liquefaction plant in Norway, Equinor holds 2023 as a best-case scenario for production at Tjeldbergodden, with 2025 as more realistic[21]. From a market perspective Equinor holds demand of 5 tons/day as a minimum, with a preferred market of 10-15 tons/day. In January 2019 a new initiative from Gasnor (gas supplier), Sunnhordland Kraftlag (hydropower) and the municipality of Kvinnherad was launched. They look towards building a liquefaction plant in Kvinnherad (approx. 2 hours south-east of Bergen) with a production capacity of 10-20 tons/day but are at a very early stage of project development.

3.3 Properties of hydrogen and other fuels

Hydrogen has a high specific energy in joule or kWh/kg, but a low energy density compared to other fuels for maritime transport. At lower heating value it contains 120 MJ/kg or 33,3 kWh per kilo and has a density of 0,08 kg/m^3 in gaseous form at a pressure of 1 bar and 70,8 kg/m^3 in liquid form.

By reducing the temperature of the hydrogen to – 252,9 degrees Celcius it converts to liquid form, which is a more suitable for distribution of large quantities. LH_2 at 0,1 MPa (1 bar)

[16] Air Liquide (2018)
[17] Air Products (2018)
[18] Praxair (2018)
[19] Linde (2018)
[20] Correspondance with Linde
[21] Øystese, Kirsten (2019)

contains about four times the energy per volume unit than does compressed hydrogen at 25 MPa's (250 bar) and almost three times as much than for 35 MPa's (350 bar)[22].

Table 4 – Properties of hydrogen and other energy carriers [23]

	Boiling point (°C 1 bar)	*Density (kg/m³)*	*Specific energy LHV (MJ/kg)*	*Specific energy LHV (kWh/kg)*	*Energy density (MJ/m³)*	*Storage temp/pressure*	*Chemical comp.*
Hydrogen	-253	0,089	120	33,3	10,8		H_2
Hydrogen compressed		23 (350 bar)	120	33,3	5 040	Ambient 200-1000 bar	
Hydrogen liquid		71	120	33,3	8 500	Cryogenic Atm./Low pressure	
MGO	175-650	890	42,7	11,97	38 000	Ambient atmospheric	Hydro-carbon
LNG	-162	440	50	12,50	22 000	Cryogenic Atm./Low pressure	Mainly CH_4
LPG	-42	490	46,4	12,90	22 740	Amb. or Cryogenic/ Atm.	C_3H_8
Liquid ammonia	-33,3	653,1	18,6	5,17	14 100	Ambient High/Atm. pressure	NH_3
Methanol	65	780	20	5,56	36 700	Ambient Atm.	CH_3OH
Biodiesel	>130	875	37,27	11,80	32 375	Ambient Atm.	

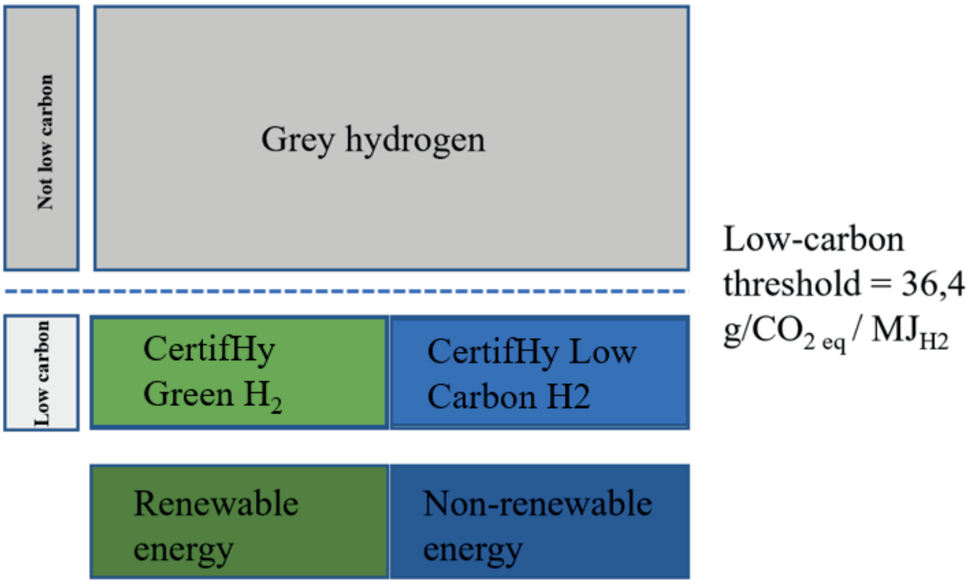
[22] Berstad et.al, 2009
[23] Berstad, 2018a, Air Products, 2014 and Baykara, 2018

3.4 Green hydrogen

Through the CertifHY-project, the EU are currently developing a guarantee of origin scheme for green hydrogen. The scheme is built up somewhat along the same principles as the market for guarantees of origin for electricity, where producers of hydrogen can purchase certificates to certify their product.

Using benchmarks for CO_2-emissions the scheme is presented in the figure below, creating categories of grey, blue and green hydrogen[24]. A pilot with 75 000 + guarantees of origins and four hydrogen producers are currently underway with feedback and a final design of the scheme. By early March 2019, 10 organisations were registered as account holders with the first commercial transactions having been publicly announced.

Figure 6: CertifHy scheme for green hydrogen



The threshold for low-carbon hydrogen is set at 36,4 g/CO_{2eq} / MJ_{H2} or about 4,36 kg/CO_{2eq} per kilo of hydrogen, which is 60 percent below a set benchmark of the best technology available at 91 g/CO_{2eq} / MJ_{H2} or about 10,9 kg/CO_{2eq} per kilo of hydrogen from gas reformation.

Certain criteria must be met in order to purchase guarantees of origin[25]:

a) Only facilities producing H_2 with GHG emissions lower than the benchmark value of 91 g/CO_{2eq} / MJ_{H2} – since sign up or over the preceding 12 months are eligible.

[24] Barth (2016)
[25] CertifHY (2015)

Under the additional conditions listed below, these facilities will be able to produce:

1) CertifHy Low-GHG H_2
2) CertifHy Green H_2 in proportion of the share of renewable energy in the non-ancillary energy used[26].

When the renewable source is either on-site or has purchased GoOs, the scheme automatically sets the CO_2-level to 0. If the scheme of origins is implemented as the standard solution, the threshold set for low carbon H_2 demands CCS in order to reduce the emission-levels enough to qualify for guarantees of origins, see chapter 4.1 for a discussion on CO_2-content in hydrogen production.

A different method to calculate CO_2-emissions was used in the tender for the first hydrogen car ferry in Norway. Here the Norwegian Public Roads Administration set a threshold using the CO_2-intensity of the energy source of which the hydrogen is produced. If an alternative energy source to the Nordic power grid is used, the CO_2-intensity per kWh cannot be higher than the CO_2-intensity of said grid[27][28].

Using the CO_2-intensity in the period from 2013-2017 as an example, we see that there is an emission-level of about 0,1 kgCO_{2e}/kWh. With 50 kWh needed to produce 1 kg of hydrogen, it would give an emission level per kg of hydrogen of about 5,15-5,7 kg CO_{2e}/Kg H_2.

Table 5 – CO_2-intensity of the Nordic Grid 2013-2017[29]

Mix	*Kg/CO_{2e} / kWH*	*Kg/CO_{2e} / Kg H_2[30]*
Nordic mix low voltage at grid	0,114	5,7
Nordic mix medium voltage at grid	0,107	5,35
Nordic mix high voltage at grid	0,103	5,15

A third certification standard is used by the German company Tüv Süd. In order to certify hydrogen as green, the hydrogen must have a GHG-reduction potential of at least 50 percent (75 percent for electrolysis with renewables) compared to fossil fuels or hydrogen from gas reformation[31]. According to DNV-GL the Tüv Süd-standard corresponds to a maximum carbon footprint of 2.7 kgCOe/kg H_2 to be labelled as green hydrogen[32].

3.5 Current and future price of hydrogen

There is no global or regional marketplace for hydrogen as a commodity, making it difficult to give a precise picture of the price level. In addition, production cost is relative to the size of the production plant, the price of electricity or natural gas and distribution costs. However, several studies have estimated both a current and future price level that can serve as a guideline. It is important to note that some predictions use production cost for hydrogen while others report a retail price for end customers, making the figures difficult to compare directly.

[26] Ancillary energy is energy consumed by machinery, which is not one of the essential directly applied energy inputs for generating hydrogen
[27] Excluded transportation of hydrogen
[28] Norwegian Public Roads Administration (2018)
[29] Asplan Viak (2018)
[30] 50 kWh/kg H_2
[31] Tüv Sud (2019)
[32] DNV-GL (2019)

The EU-project Fuel Cells and Hydrogen – Joint Undertaking (FCH-JU) estimates a production cost of 4-5 Euro/kg in order to achieve profitable solutions for end users in mobility (land) and industry[33]. In a literature review of market growth from 2015 Hinicio finds that three separate studies converge on the conclusion that a retail price of 5-7 Euro/kg is realistic in 2030[34].

In 2014 a large study on electrolysers and hydrogen production found the price target from FCH-JU within range. Taking into an account of estimated price reductions for electrolysers of 50 (alkaline) and 60 (PEM) percent and increased efficiency reducing the kWh/kg of hydrogen, the study estimated future prices for five different European markets. With a price range between 2,2 and 5,0 Euro/kg hydrogen, best case scenarios are competitive with SMR at 2,5 Euro/kg H2[35].

In a study from the US Department of Energy, based on US prices for natural gas, the production cost for hydrogen from SMR is predicted to be between 1,7 and 2,1 USD/kg, without compression, storage and dispensing. Using brown coal fuel, Kawasaki has estimated a production cost of 24 yen/Nm^3 or just below 2 Euro/kg hydrogen for their Australia-based production plants. The price includes CCS and liquefication, but not export to Japan[36].

The industry initiative Zero Emission Platform reference a current production cost of 2-4 Euro/kg H2 from SMR and 4-8 Euro/kg H2, arguing that increasing gas prices and reduction cost on electrolyzers and other infrastructure would level hydrogen prices, independent of production form towards 2050[37].

IRENA estimate a current (2018) production price for hydrogen of 5-6 USD/kg H2 and a retail price of 13-16,5 USD/kg H2 Target prices varies from 3 USD/kg H2 (Japan), 5 USD/kg H2 (US) and 6 USD/kg H2(Europe)[38].

In Norway, DNV-GL estimates a price range from 20 to 50 kr/kg hydrogen from electrolysis in 2030 and about 9 to 16 kr/kg H2 from gas reformation. The price range depends on the cost of energy input, CCS and choice of technology[39]. In a forthcoming report, the Green Coastal Shipping Programme estimates a price of 3 USD/kg for hydrogen from electrolysis and an assumption of 3,5 USD/kg for liquified hydrogen[40].

As the literature review confirms, it is difficult to establish a price for hydrogen. Most studies seem to converge towards a production cost of 2-3 Euro/kg for compressed hydrogen. For large scale liquid hydrogen, some studies indicate a future price around 2 Euro/kg, but this is dependent on major technological development and larger scale[41]. Based on information from the IDEALHY-project, it takes around 11-15 kWh to liquify1 kg of compressed hydrogen[42]. With Norwegian energy prices w/tariffs of around 0.1 Euro/kWh – that would add an additional 1-1,5 EUR/kg to the production price. In addition, the investment cost for the Leuna facility, operated by Linde and commissioned in 2008 was around 20 MEUR[43]. From a

[33] Tractabel Engie & Hincio (2017)
[34] CertifHY (2015b)
[35] E4Tech Sarl and Energy Element (2014)
[36] Kawasaki (2018)
[37] ZEP (2017)
[38] Irena (2018)
[39] DNV-GL (2019)
[40] Green Coastal Shipping Programme (forthcoming)
[41] Stolzenburg et.al (2013)
[42] Stolzenburg et.al (2013)
[43] Krasae-In (2013)

similar sized LH_2- plant in Europe as Leuna, the reported retail price (ex. Distribution) is 7,1 Euro/kg[44].

Table 6 – Summary of price estimates[45]

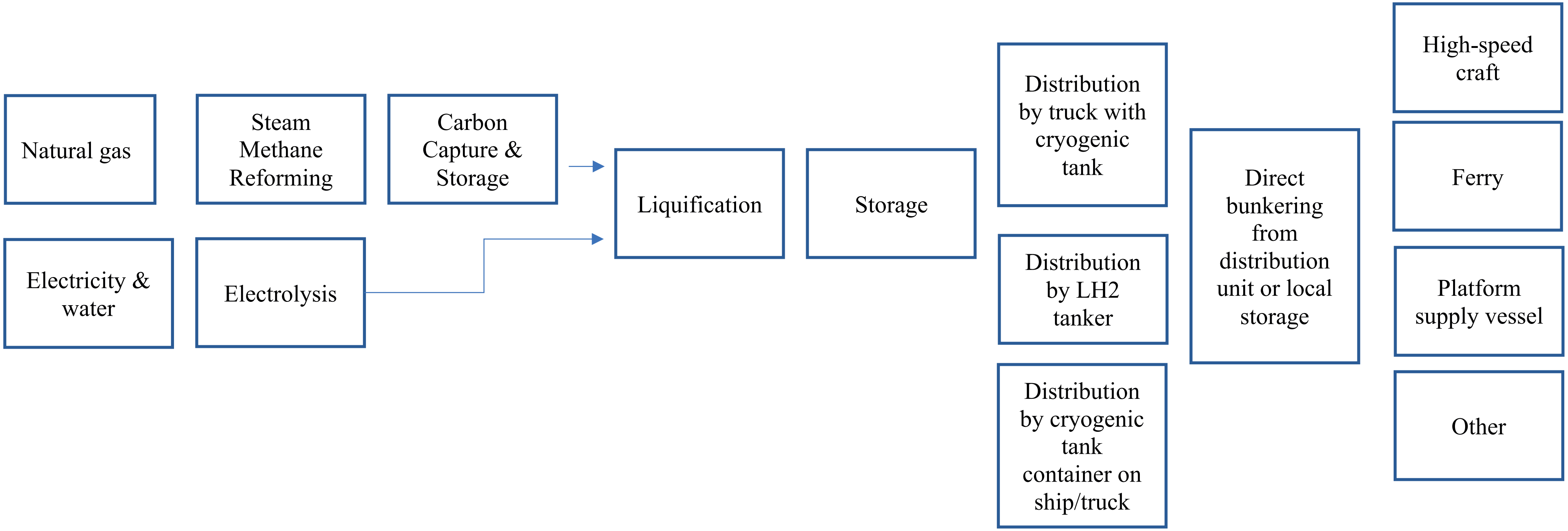
Source	*Production cost/kg*	*Retail Price/kg*	*Year*	*Compressed/ Liquid*	*Electrolysis/SMR*
FCH-JU (2017)	4-5 Euro		2025	Compressed	Unknown
Hinicio (2015)	5-7 Euro		2030	Compressed	Unknown
E4 Tech (2014)	2,2-5,0 Euro		2014	Compressed	Electrolysis
E4 Tech (2014)	2,5 Euro		2014	Compressed	Gas reformation
US DOE (2012)*	1,5-1,9 Euro		Price for period of 2020-2039	Compressed	Gas reformation
Idealhy (2013)	1,72 Euro		N.A, price for specific plant 50t/day	Liquid	Electrolysis
Kawasaki (2018)	2 Euro		Estimation current project plans	Liquid	Coal gasification
ZEP (2017)	2-4 Euro		Current market price	Compressed	Gas reformation
ZEP (2017)	4-8 Euro		Estimated current market price	Compressed	Electrolysis
ZEP (2017)	3 Euro		2045-2050	Compressed	Electrolysis/gas reformation
Shell (2017)	Ca 1,5-4 / 1,8-3 Euro		Weighted current / projected market price	Compressed	Gas reformation
Shell (2017)	Ca 6-8 / 4 Euro		Weighted current / projected market price	Compressed	Electrolysis
IRENA (2018)*	4,4-5,3 Euro		Estimated current market price	Compressed	Electrolysis
IRENA (2018)*		11,5-14,5 Euro	Estimated current market price	Compressed	Electrolysis
IRENA (2018)*	0,9-2,6 Euro		2025-2030	Compressed	Electrolysis
IRENA (2018)*		4,4-6,1 Euro	2025-2030	Compressed	Electrolysis
*GCSP (2019)**	2,7-2,8 Euro		2019	Compressed	Electrolysis (Alkaline and PEM)
*GCSP (2019)**	3 Euro		2019	Liquid	Unknown
DNV-GL (2019)*	2-5 Euro		2030	Compressed	Electrolysis (Alkaline and PEM)
DNV-GL (2019)*	1-1,6 Euro		2030	Compressed	Gas reformation
Greensight[46]		7,1 Euro ex. Distribution	Current market price	Liquid	Gas reformation
Greensight		11 Euro incl. distribution	2020 in Norway in the Oslo-area, commercial long-term contract	Compressed	Electrolysis
Greensight		7,5 Euro incl. distribution	2023/4 in Norway in the Oslo-area, commercial long-term contract	Compressed	Electrolysis
*Klebanoff & Pratt (2016)**		5,2-6,5 Euro	Current market price	Liquid	Unknown – prob. Gas reformation

44 Correspondance with supplier
45 *Converted from USD to Euro with an exchange rate of 0,88 EUR/USD or NOK to Euro with an exchange rate of 9,84 NOK/EURO
46 Based on correspondence with suppliers and industrial knowledge

4. Value chain liquid hydrogen (LH2)

The focus in this chapter is the Norwegian future value chain for LH2 and includes methods and solutions relevant from a Norwegian perspective. The two production methods included are therefore: 1) gas reformation using natural gas with CCS and 2) electrolysis using electricity and water. The value chain includes production of hydrogen and subsequent liquefaction to storage solutions and distribution to end users.

Figure 7: Norwegian future value chains for liquid hydrogen



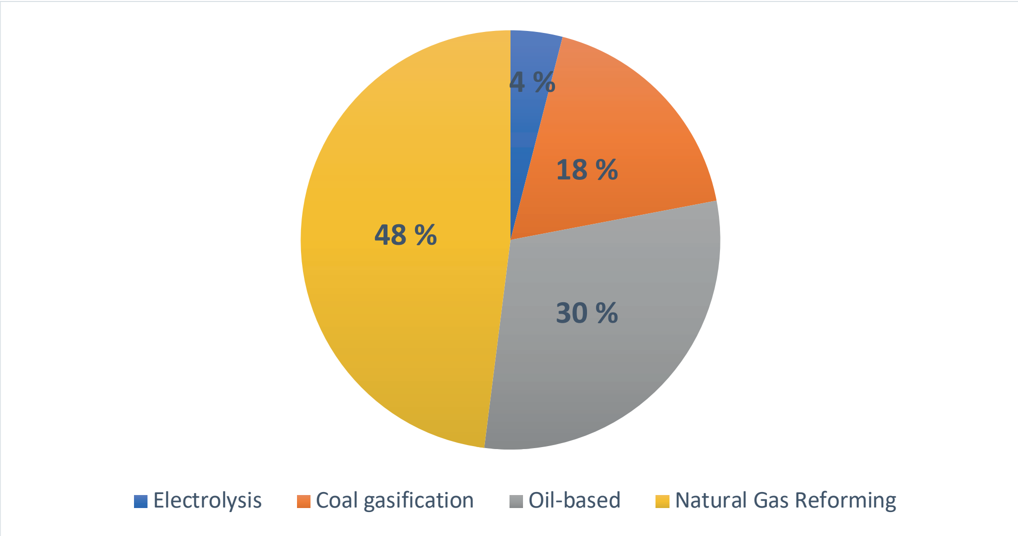
4.1 Production processes

Over 95 percent of the current hydrogen production is fossil-fuel based, using oil, coal or gas as the energy source. Reforming of natural gas is the most dominant production form, and most cost and energy efficient. Most sources report about 48-50 percent, such as IRENA (2018), IEA (2015) and Hydrogen Council (2018), but Shell (2017) reports share of 60 percent of annual hydrogen production from gas reformation. In large scale production, the energy input in form of natural gas is typically 22 to 28 kWh/kg H2 with an efficiency of around 70-80 percent[47].

About 4 percent is produced by electrolysis where electricity is used to split water into hydrogen and oxygen[48]. With a typical electrolyser efficiency of 60 percent, it requires between 50 to 60 kWh to produce one kilo of hydrogen.

Norway has large amounts of both natural gas, 121 billion Sm^3 in 2018[49], and about 10 TWh of surplus hydropower in 2018[50]. Thus, from an energy perspective Norway is well suited to produce hydrogen from both gas reformation with CCS and electrolysis.

Figure 8: Hydrogen by production method[51]



4.1.1 Hydrogen from gas reformation

The most common form of hydrogen production today is steam-methane reformation (SMR)In SMR the methane reacts with steam in the presence of a catalyst to produce hydrogen, carbon monoxide, and carbon dioxide. Subsequently, in what is called the "water-gas shift reaction," the carbon monoxide and steam are reacted using a catalyst to produce carbon dioxide and more hydrogen. In a final step the carbon dioxide and the hydrogen gas stream, are separated[52].

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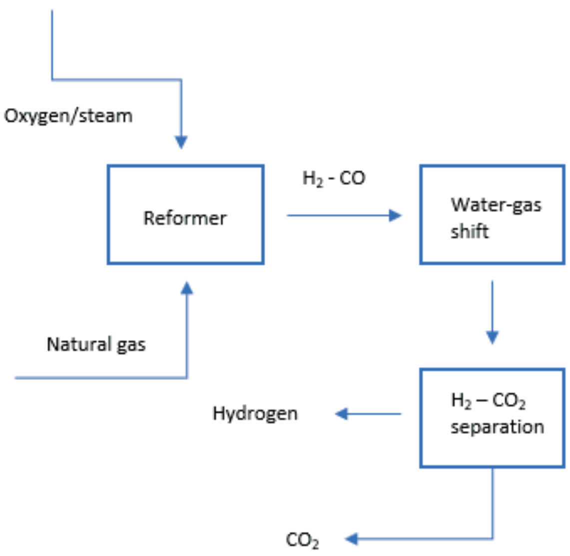
[47] Holst, Steffen Møller et. al (2016)
[48] IRENA (2018)
[49] Norsk Petroleum (2019)
[50] Statistics Norway (2019)
[51] IRENA (2018)
[52] Office of Energy Efficiency and renewable energy (2019)

Other technologies are partial oxidation using pure oxygen instead of steam as an oxidant and autothermal reforming using a combination of steam and oxygen. In a recent study on the introduction of hydrogen in the British gas grid, Auto Thermal Reforming (ATR) is looked upon as a better solution than SMR – both in terms of investment cost, size and ability to capture CO_2. [53]

The reported amounts of CO_2 per kilo hydrogen from gas reformation varies. Soltani et.al finds that the emissions from the production are about 7kgCO_2/kgH_2[54]. In a more recent analysis of the International Energy Agency Greenhouse Gas R&D Programme (IEAGHG) finds an emission level of ca. 9kg CO_2/kgH_2[55] from a standalone merchant hydrogen plant.

From life cycle perspective, it is necessary to also include emissions from the production of natural gas, in the range of 1-5 kgCO_2/kgH_2 based on data from US gas production[56]. Calculations made by Equinor shows that the expected carbon footprint from the Norwegian continental shelf is about 11-12 kgCO_{2e}/MWh of gas, translating into 0,5-0,6 kgCO_2/kgH_2. Thus, the combined emission level from gas reformation in Norway is just below 10 kgCO_2/kgH_2[57].

Figure 9 – Hydrogen by gas reformation



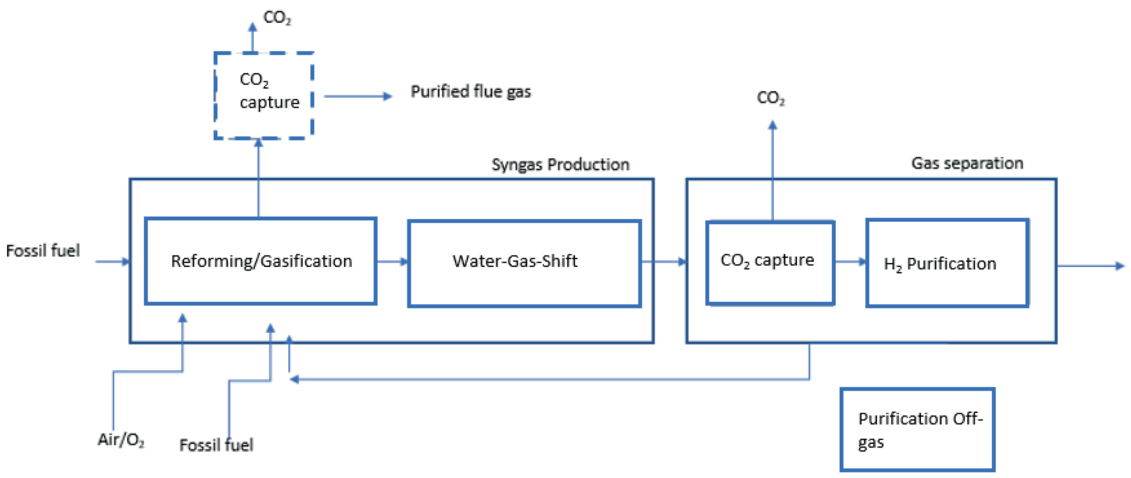
While still in an early phase, there are already commercially available technologies for carbon capture in hydrogen production from natural gas and in use in all major markets[58][59].

The most mature technology for carbon capture is absorption with solvents, such as amine technology. Here the CO_2 is captured by an amine solvent, a liquid compromising of water

[53] H21 (2018)
[54] Soltani, Rosen and Dincer (2014)
[55] IEAGHG (2017)
[56] NETL, 2015 in DNV-GL (2019)
[57] Calculations in DVL-GL (2019) with input from Equinor (2017)
[58] Voldsund (2016)
[59] ZEP (2017)

and amines. This takes place after the water-gas-shift and before the hydrogen stream is cleaned, as shown in the figure provided by researchers at SINTEF below[60].

Figure 10 – Carbon Capture from Steam-Methane Reforming



A different technology is the cold capture system Cryocap, developed by Air Liquide and put in use at their production facility in Port-Jerome in Normandy in 2015. Here, low temperatures compress, liquefy and then separates the gases[61].

Studies show that it is possible to capture over 90 percent of the emitted CO_2 from SMR, making the CO_2-intensity well below 1 kg/CO_2 per kg H_2[62]. In the proposed H21 North of England-project to convert the gas networks across the North of England to hydrogen, analysis estimate a CO_2 capture-level of 94,2 percent and a CO_2-footprint of 14,14 g/kWh[63].

IEA Greenhouse Gas (IEAGHG) reports a capture rate of between 54 and 90 percent of emissions, from a study using different technologies to capture CO_2[64].

In the H21-project the captured CO_2 is going to be stored beneath the North Sea, on UK Continental Shelf. The cost of establishing the necessary infrastructure for transport and storage of CO_2 is estimated to be £ 1 340 million with a yearly operational cost of £ 24 million. The proposed project looks to store an average of 17 million tons of CO_2 per year, taking maximum effect of economies of scale and estimates a cost between £ 5 and 10 per ton CO_2. Research from Sintef give a rough estimate of transportation costs in a CCS-system at 10-20 Euro/ton CO_2[65]. With an average CO_2-content of 10 kg/kg H_2, if produced with gas from the Norwegian continental shelf, the transportation of CO_2 alone would be between 0,1 and 0,2 Euro per kg H_2.

In terms of storage, CO_2-storage has been in operation on the Sleipner-field since 1996. Currently plans are being made for a large-scale storage facility at Smeaheia – west of the refinery at Kollsnes[66]. In the feasibility study CO_2 from three sources are to be transported by

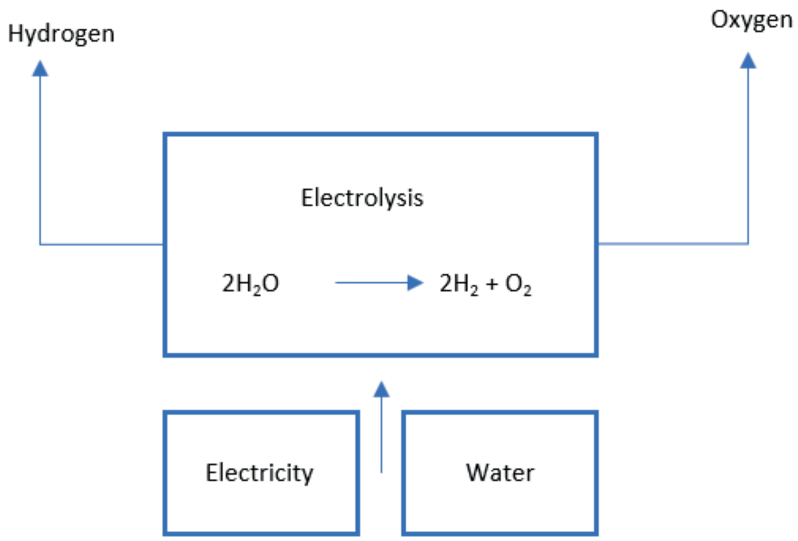
[60] Sintef (2016)
[61] Air Liquide (2015a)
[62] Berstad (2018b)
[63] H21 (2018) – H21 is a partnership between Northern Gas Networks, Equinor and Cadent
[64] IEAGHG (2017)
[65] Holst, Steffen Møller et.al (2016)
[66] OED (2016)

ship to an onshore facility at Kollsnes for further transport by pipelines to the storage site. The project costs have been estimated to between 7,2 and 12,6 billion NOK (ext. VAT). A final investment decision is yet to be made.

4.1.2 Hydrogen from electrolysis

In electrolysis water is split by electricity to produce hydrogen and oxygen. If the source of electricity is renewable there are no CO_2-emissions in the production of hydrogen.

Figure 11: Hydrogen by electrolysis



The source of electricity for the hydrogen produced by electrolysis today is not known, but it reasonable to assume that it in many cases it comes from a mix of renewables and fossil sources. As an example, the CO_2-emission factor in Norway in 2017 was 16,4 g/kWh[67], while the EU-mix in 2016 was estimated to 295,8g/kWh[68].

In a literature study the International Renewable Energy Agency present an expected decrease in total system cost for alkaline electrolysers from 750 EUR/kW in 2017 to 480 EUR/kW in 2025 and a drop from 1200 EUR/kW to 700 EUR/kW for PEM electrolysers[69].

4.1.3 Gasification and other production forms

Gasification is a process where fuels, such as oil, coal or biomass, is dried and heated without sufficient supply of oxygen for a complete combustion, thus creating a syngas consisting mainly of hydrogen and CO_2. In a water-gas-shift reaction, CO_2 and water is converted to CO_2 and hydrogen as two separate streams. There are also other production forms that does not fall in under the three categories we have presented, see Shell (2017) or DNV-GL (2019) for an overview.

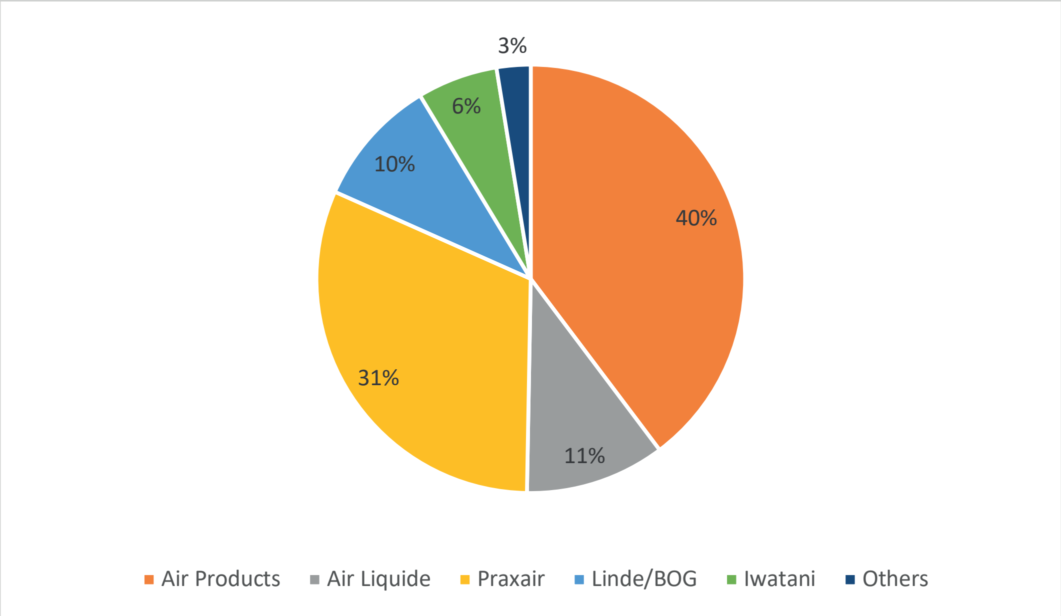
[67] NVE (2018)
[68] European Environment Agency (2018)
[69] Irena (2018) – Total system cost include power supply and installation costs

4.2 Liquefaction

Regardless of production method, hydrogen becomes a liquid at -253 °C. At ambient conditions, the theoretical minimum energy to liquefy hydrogen is 3,3 kWh / kg[70]. As the main input of liquid hydrogen is hydrogen, the liquification plants are built where hydrogen can be supplied. Furthermore, as hydrogen is today sourced primarily from natural gas; most hydrogen liquification plants are located at natural gas terminals and liquefied at the hydrogen production site. Finally, hydrogen is best produced near demand points as it is expensive to transport due to its characteristics.

The market place for commercial scale, economical liquefaction plants is dominated by Linde, Air Products and Praxair:

Figure 12: Global producers of liquid hydrogen[71]



Liquefaction Method

Large scale hydrogen liquefaction facilities, which are present only in Northern America, were largely developed during the space race in the 1950's and 1960's for NASA. As hydrogen is a standardized product the production method is not of much concern other than to the cost and the reliability (which can also be tied to cost) of the process.

In working to optimize the lowest cost per kilo of production, there are trade-offs between capital expenditures which are upfront fixed costs regardless of actual production levels and operational expenditures which are variable based on production levels. This gives rise to two primary methods or cycles for liquefying hydrogen, namely; The Reverse Helium Cycle & The Claud Cycle.

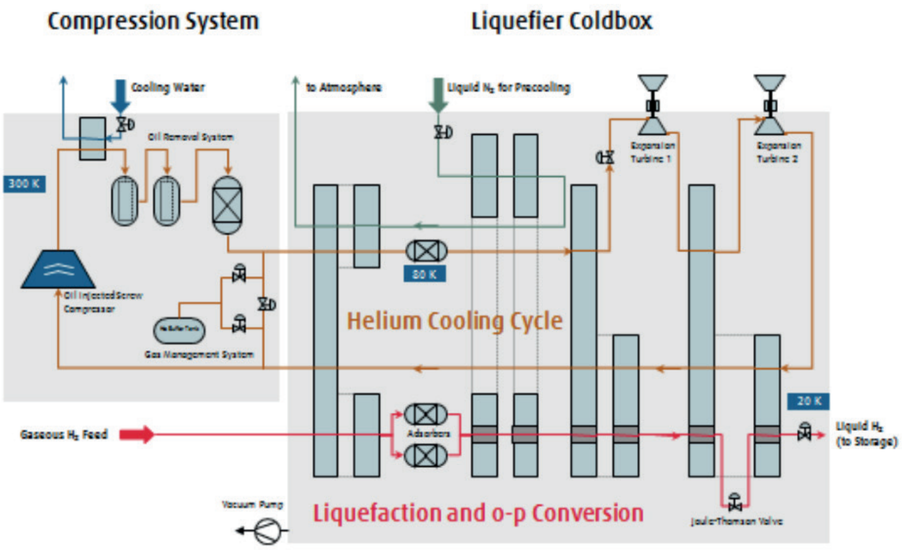
Reversed Helium Brayton Cycle: Small scale plants (up to 3 TPD) rely on the Reverse Helium Brayton Cycle where the capital costs tend to be lower while the operating costs tend

[70] Gardiner (2009)
[71] Krasae-in, Stang and Neksa (2010)

to be higher. The Reversed Helium Brayton cycle begins with compressed hydrogen at 10 – 15 bar injected into the process. Liquid nitrogen is then used for pre-cooling of the hydrogen to approximately -193 degrees Celsius or 80 Kelvin. The liquid nitrogen is then subsequently vented to the atmosphere and not recycled.

The hydrogen is then cooled using expansion turbines through a helium cooling cycle and finally through a Joule Thomson valve. The use of helium enables the use of low-cost oil-injected screw compressors because of this, the plant is able to avoid hazardous area requirements and therefore further reducing associated investment costs. Consequently, the low-cost compressors are inefficient and therefore result in higher energy use and therefore higher energy costs. Current energy use from this process ranges from 13,4 – 12,3[72].

Figure 13: Schematic drawing of Helium Brayton Cycle

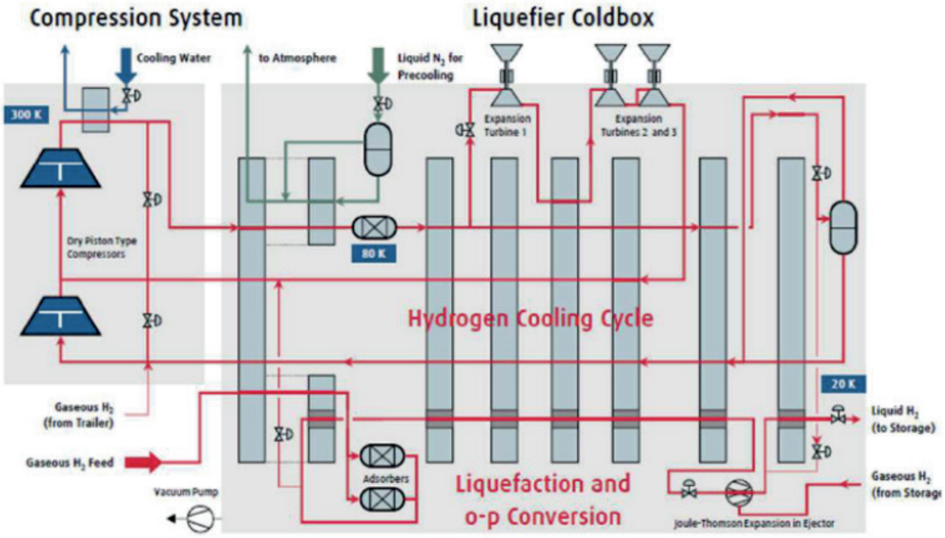


Claud Cycle: Large scale plants on the other hand, rely on the Claude cycle where capital costs are higher but the production levels are high enough that the lower operational costs (per unit) offset this. Every current large-scale liquefaction system is based on a version of pre-cooled Claude Cycle. For the beginning of this process a feed pressure of 15 – 25 bar is required.

Like the Brayton Cycle, liquid nitrogen is then used for pre-cooling of the hydrogen to approximately -193 degrees Celsius or 80 Kelvin. The liquid nitrogen is then subsequently vented to the atmosphere. After the pre-cooling cycle the process differs from that of Helium Brayton by using recycle compressors to cool hydrogen and finally through a Joule-Thomson valve where it is cooled from 30K to 20K during expansion.[2] Current energy use from this process ranges from 12,7 – 10,8.[73]

[72] The description, facts and illustration of the Helium Brayton Cycle is based on Ohlib and Decker (2015)
[73] The description, facts and illustration of the Claud Cycle is based on Ohlig and Decker (2014)

Figure 14: Schematic drawing of Claud Cycle



Hydrogen liquefaction plant costs (CAPEX) vary significantly by location, time of production and production capacity and other factors such as synergistic location together with other processes such as LNG. However, it is still possible to sketch lines on CAPEX costs and drivers.

Two major relationships between CAPEX and hydrogen liquefaction costs:

- Increased CAPEX investments enable reductions of specific OPEX costs
- Increased plant scale offers reduced specific CAPEX and specific OPEX costs

The strength of the effect of CAPEX on OPEX is unknown other than to know that as overall CAPEX is increased, specific OPEX costs (cost per kg liquefied) decreases. If the cost of electricity input is known, the tolerable investment cost to lower electricity consumption can be calculated. For example; if power consumption is reduced by 1 kW (required effect) an increase of CAPEX by $2 000 can be justified (assuming 8 000 h / year operation & $0,05/kWh, 5-year payback period)[74].

Finally, specific CAPEX costs can be further reduced by constructing multiple liquefaction plants under the same specifications therefore spreading the research and development costs. A possible additional outcome of construction multiple plants with the same design is economies of scale, particularly on compression and other equipment produced specifically for use in hydrogen liquefaction plants. Since there has been little activity in the market there are few numbers which can be accurately relied upon for hydrogen liquefaction plant capital costs.

[74] Essler et.al (2012)

Figure 15: Selection of Investment Costs, Capacities & Efficiencies of Actual & Forecasted Liquefaction plants[75]

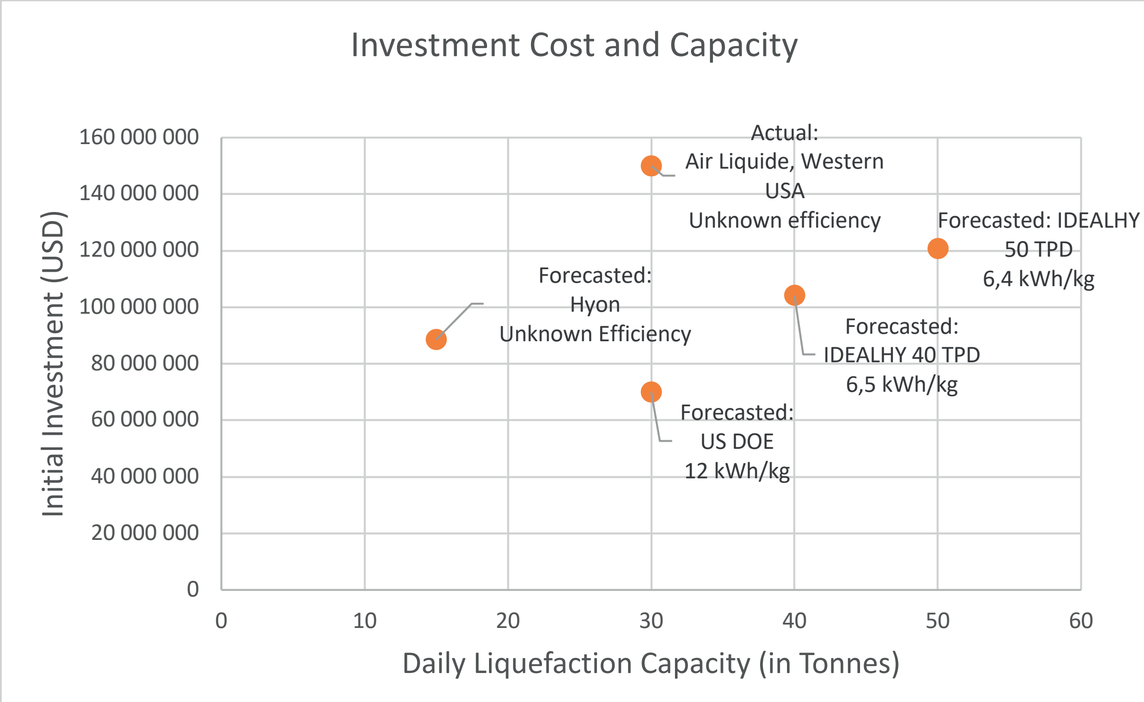
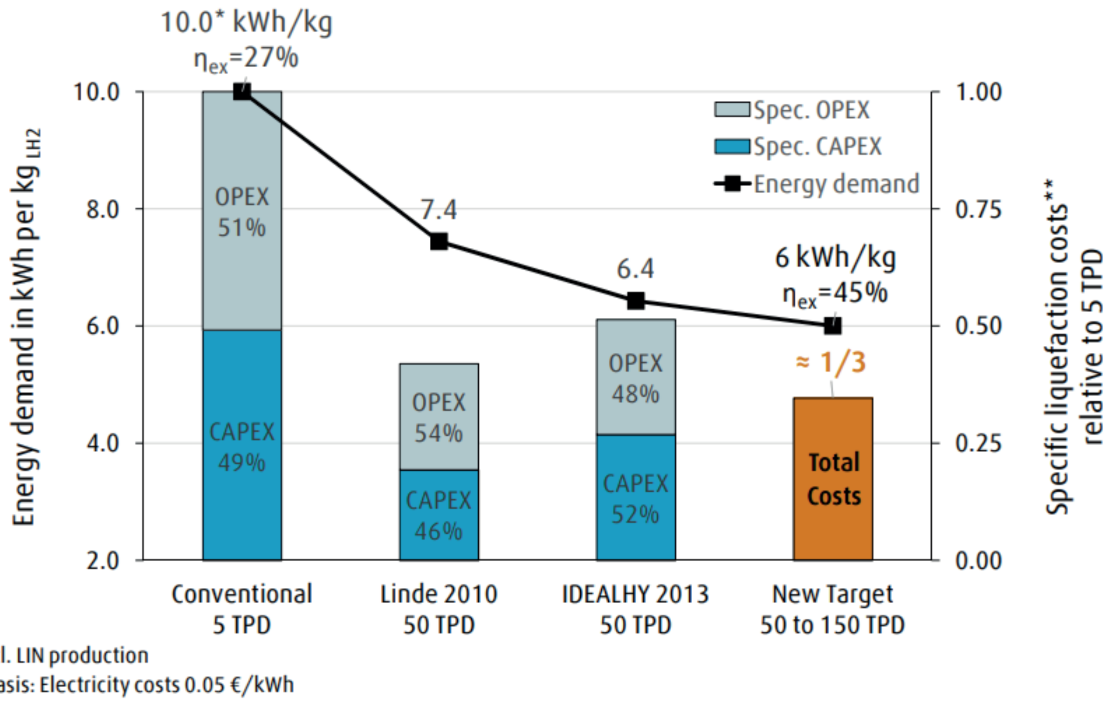


Figure 16 shows relative capital cost reductions expected in the near to medium future on new liquefaction plants.

Figure 16: Summary of Current and Projected Liquefaction Costs & Efficiencies[76]



75 Put together by the authors from a substantial literature review
76 Cardella et al (2017)

In terms of OPEX, hydrogen liquefaction variable costs are mostly related to the cost of liquid nitrogen for pre-cooling and the electrical energy required for compression. Beyond this is labour and general overhead and maintenance costs[77].

Future developments

Hydrogen liquefaction plants processes have not changed significantly in the past 50 years[78]. There are varying approaches and plans for reducing the cost and increasing the efficiency of liquefaction plants. The Integrated Design for Efficient Advanced Liquefaction of Hydrogen (IDEALHY) project was a project that brought together world experts to design an efficient hydrogen liquification process in both energy and cost efficiency[79]. The project was funded by the European Union and was done in collaboration with academic and industry partners.

According to IDEALHY, the strategy for increasing plant efficiency compared to current liquification plants rests on 3 core drivers:

- Increasing plant scale
- More efficient process design
- Using more efficient components

Results of the study showed that 6,4 kWh/kg can be achieved. The estimated plant size for this to be technically and commercially feasible is 40 - 50 tpd. The estimated investment cost of such a plant is 105 MEUR at 50 tpd. The proposed changes build on both current liquefaction techniques. The main highlights of the proposed changes include closed refrigeration loops for pre-cooling, a Reverse Brayton Cycle using improved turbine design with mixed refrigerant consisting of helium and neon[80].

Beyond IDEALHY research, Linde, estimates that they could produce an improved and scaled up version of the Leuna plant for lower overall specific costs but with higher energy usage. In either case, it seems likely that scaling up hydrogen production offers a 50 percent reduction to today's specific liquefaction costs[81]. See Figure 16 for further details.

Below we show the findings of Ohlig and Decker (2014) on developments and outlook for hydrogen liquefaction.

[77] Evans West (2003)
[78] Krasae-in et. al (2009)
[79] Essler et.al (2012)
[80] Essler et.al (2012)
[81] Ohlig and Decker (2014)

Table 7: Summary of Select Liquefaction Current and Future methods

	Current Technology		*Short Term Future*	*Medium Term Future*
Liquefaction Capacity, tpd	**<3**	**2 - 15**	**15 - 30**	**<200**
Main Rerigeratin Cycle	Brayton	Claude	Claude	Claude
Refrigeration Medium	Helium	Hydrogen	Hydrogen	Hydrogen
Pre-cooling Cycle	LN_2	LN_2	Chiller & N2 Cycle	N2 / Mixed Refrigerant Cycle
Compressor Type	Oil Flooded Screw	Piston	Piston	Piston
Feed Pressure (Bar)	10 - 15	15 - 20	20 - 25	> 20
Specific Power (kWh / kg H2 (Including feed gas compression & precooling)	**13,4 - 12.3**	**12,7 - 10,8**	**10,8 - 7,7**	**9 - 7,5**
Operating Cost (OPEX)	Highest	Low	Lower	Lowest
Investment Cost (CAPEX)	Low	Medium	Higher	Highest

4.3 Storage

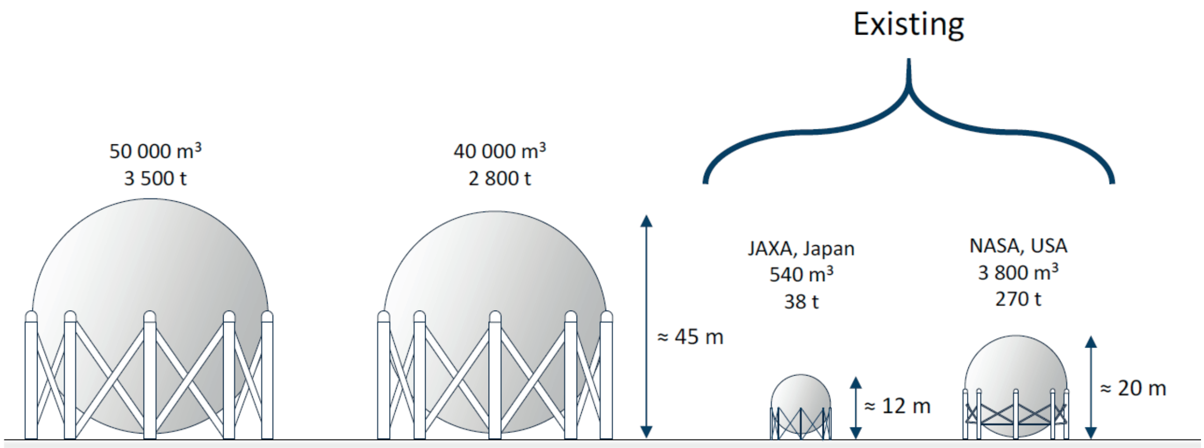
Cryogenic storage tanks are perhaps the part of the value chain with the highest technology readiness level, as several suppliers offer storage solutions for a range of volumes. As an example, Linde supplies LH_2 storage tanks up to 300 m^3 [82].

The largest single cryogenic storage tank in the world belongs to NASA in Florida, USA. The tank is 3800 m^3 and has a capacity of 270 tons liquid hydrogen[83]. In addition, JAXA has a 540 m^3 storage in Japan with a capacity of 38 tons LH2[84]. Both are associated with the spacecraft industry. A new LH2 storage tank is about to be constructed at NASA, with a capacity of 375 tons liquid hydrogen[85].

The future size of liquid hydrogen storage tanks can be about 13 times bigger than the NASA one, and have a maximum capacity 3 500 tons hydrogen.

[82] Linde (2016)
[83] Gas World (2019)
[84] Sintef (2018)
[85] Houston Chronicle (2019)

Figure 17 – Current liquid hydrogen storage[86]



NASA claims that liquid hydrogen can be stored without any losses for an indefinite period of time using Integrated Refrigeration and Storage (IRaS), a system allowing control of the fluid inside the tank. By using IRaS the liquid is stored in a zero boil-off state, so that the heat leak entering the tank is removed by a cryogenic refrigerator with an internal heat exchanger[87]. IRaS combined with a new glass "bubble" insulation has replaced the perlite powder that was state-of-the-art in 1965 in favour of lower losses[88].

The cost of storage is unclear. LNG-tanks have typically an investment cost of 30-40 USD/kg for tanks above 100 tons and 80-100 USD/kg for smaller cryogenic tanks[89]. Klebanoff & Pratt (2016) give a price of 625 000 USD for a 4,2 tons LH_2-tank indicating a price level 45-50 percent higher tank for LNG-tanks. The US Department of Energy reports a current price for a LH_2-storage tank containing 3500 m^3 at 6,6 million USD, with an "ultimate goal" of a price reduction to 3,3 million USD[90].

4.4 Distribution

Distribution by truck with cryogenic tank

According to Linde, who is a world leading supplier of industrial, process and speciality gases, liquified gases are transported in tank trucks and stored in cryogenic vessels. The tanks are designed to store the materials at the correct temperature and pressure and can range from approximately 140 kg to 4 tons depending on the requirements[91]. A heel of liquid hydrogen must be left in the truck so a truck that has a nominal holding capacity of 4,6 tons deliver 4,1

[86] Sintef (2018)
[87] W U Notardonato et al (2017)
[88] Gas World (2019)
[89] Green Coastal Shipping Programme (forthcoming)
[90] Energy.gov (2015)
[91] Reddi, Krishna et. al (2016)

tons[92]. A distribution truck with a capacity of four tons, undercarriage and cab is estimated to cost around 800 000 USD[93].

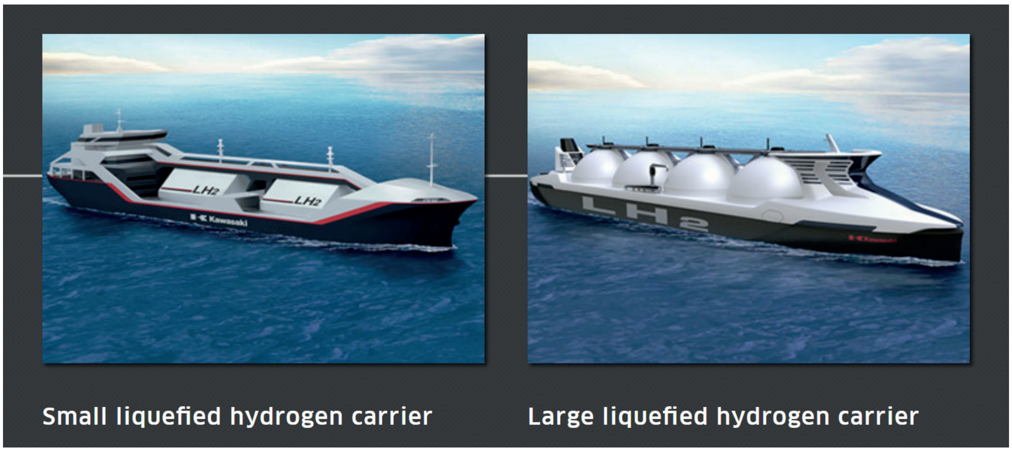
The tanks have an inner vessel, often referred to as the liquid container which is surrounded and supported by an outer vessel or "vacuum jacket". The space between the inner and outer vessel is filled with a natural material that provides insulations and inertness. The delivery system includes piping which carries gas from the inner vessel through the vacuum jacket to the outside, controlled by gauges and valves mounted outside of the tank[94].

Distribution by LH_2 tanker

There are no existing LH_2 tankers operating yet, but Kawasaki has designed two tankers; a small and a large liquefied hydrogen carrier. The small carrier has a capacity of 2 500 m^3 and the large carrier has a capacity of 160 000m^3, respectively 180 and 11 400 tons of hydrogen. A boil-off rate of 0,2 per day has been given by Kawasaki[95].

The ships are designed to sail between Japan and Australia, where a large amount of brown coal is used to produce hydrogen for power-generation companies, transport and others.

Figure 18 – Kawasaki's Small and large LH_2 tankers



A demonstration ship will be delivered for tests in 2020. The ship is designed to be about 116-meter-long and can accommodate two cargo containment systems of 1 250m^3 each. The cargo containment system can accumulate boil-off gas for up to 21 days at sea. Hydrogen is not used for propulsion, it is driven by electric motors that receive power from generators driven by diesel engines[96].

Moss Maritime, together with several partners, has also developed a design for a hydrogen distribution/bunkering vessel which will be addressed in chapter 4.5 on bunkering.

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[92] Nexant (2008)
[93] Yang and Ogden (2007)
[94] Linde (2019)
[95] Kawasaki (2014)
[96] LNG World Shipping (2017)

Distribution by cryogenic tank container on ship

In terms of transporting LH_2 in containers on ships, there are two ways of doing so; transport by truck on a RoRo ferry on top deck or shipment by ISO containers on intercontinental containerships[97]. In the latter case road transport is still needed from production site to ferry and from ferry to point of discharge, and in both cases the distribution is subject to the ADR-rules in transportation of dangerous goods.

Figure 19: Transport by cryogenic tank on ship

4.5 Bunkering

While there are refuelling stations for liquid hydrogen for land-based transportation, a commercially available solution for maritime bunkering is yet to be developed. In the feasibility study for the SF BREEZE-project, the consortium behind had conversations with leading industrial gas companies to analyse the fuelling infrastructure for the planned high-speed craft.

In their design, they identified three primary components illustrated in figure 26: LH_2 source tank (permanent or trailer mounted), inert gas supply, and flexible bunkering hose assembly. Here they use a pressure fill (flow by differential pressure of the two tanks), another solution would be a pump-assisted fill.

The bunkering station consists of two hose connections, one for hydrogen/inert gas fill, and one for cooldown gas return. These will be connected via hose to the shoreside facility. The inert gas is used to remove air and moisture before bunkering to ensure a pure fuel supply. If liquid helium is used as an inert gas, this will also provide pre-cooling of the lines, as it has a lower boiling point than LH_2.

In the following figures two different solutions is presented schematically. With the use of a pressure build loop on the shoreside hydrogen tank, the pressure in the lines may be increased enough to perform the transfer without the use of a pump. If not a LH_2-pump is necessary to complete the transfer. A LH_2-pump is estimated to consume 0,8 kWh/kg[98] but can increase the flow rate significantly[99].

[97] Correspondence with Peter Bout (Air Products), 30th of October 2018
[98] CMR Prototech (2014)
[99] Cryostar (2019) reports a maximum capacity of 600 m^3/h for a submerged LH_2-pump.

The US Department of Energy estimate the current price level of an LH_2-pump (5 bar, 1720 kg/h) to be 80 000 USD, with a target price in 2020 at 70 000 USD and an “ultimate goal” of 57 000 USD[100].

Figure 20: Flow-schematic of an LH_2-bunkering facility – pressure fill[101]

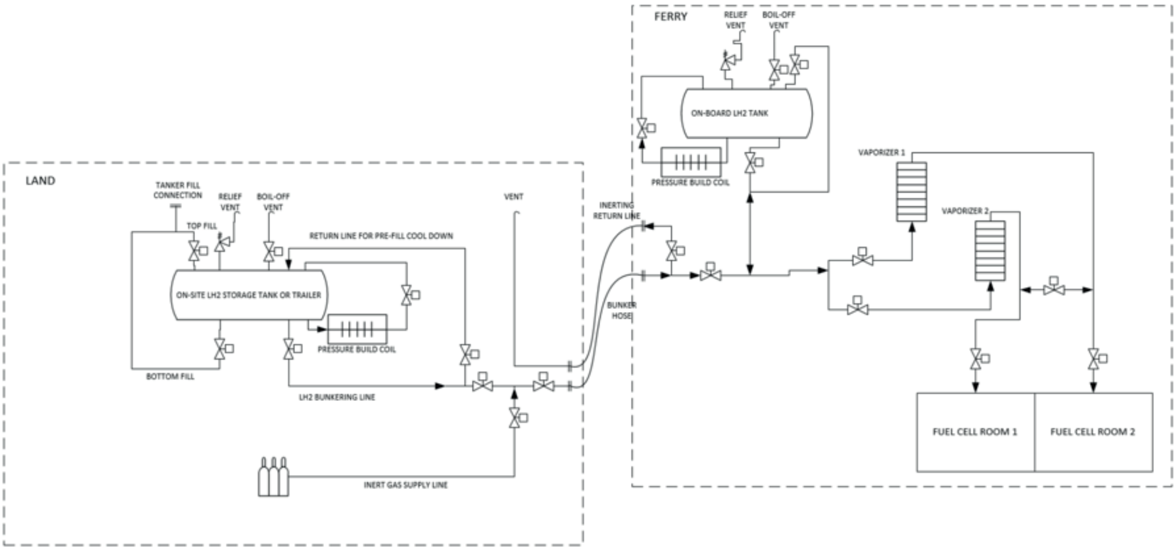
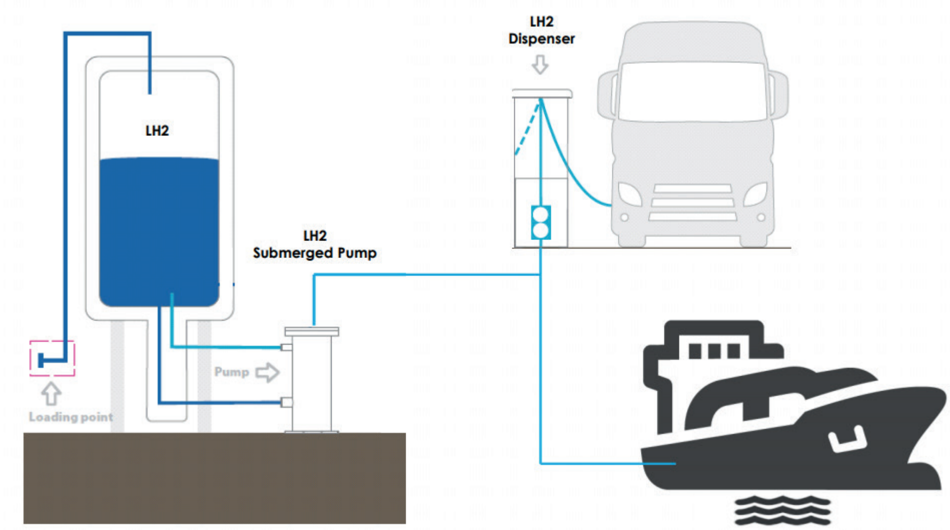


Figure 21: Schematic presentation of bunkering by LH_2-pump[102]



In their study Klebanoff and Pratt (2016) compare LH_2-bunkering to that of LNG, with a few special considerations, the most important being the lower boiling point (-253 C to -162 C). This calls for shorter fill lines to minimize the cooling process before bunkering. Even so, the time needed to cool warm lines and equipment prolongs the bunkering procedure. It is estimated that a 1000 kg fill process may take 40 minutes for cooldown, 30 minutes for LH_2-transfer and 30 minutes for purge and warm-up prior to disconnect. This, they state, can

[100] Energy.gov
[101] Pratt & Klebanoff (2016)
[102] Cryostar (2016)

partially be handled by pre-cooling before the vessel arrive for bunkering. A transfer flow rate of 1000 kg in 20-40 minutes was deemed “straightforward”, regardless of filling method.

This is several times faster than the flow rate of 500 kg/hour that was deemed necessary in a project led by CMR Prototech (2014) to refuel a PSV in 12 hours[103]. With the flow rate suggested in the SF BREEZE-project a PSV would need 2-4 hours to fill six tonnes of hydrogen, plus cooling and warming of lines and equipment before and after the transfer. In the Zero-V project for a hydrogen-fuelled research vessel, a total of 3,5-4 hours for the delivery of four tons of LH_2 is estimated. Here the bunker piping system is designed to facilitate a parallel fuelling of two separate tanks[104].

In the Zero-V project, the industrial gas companies consulted gave advice for the bunkering to use a fuelling stanchion, instead of connecting the hoses directly between the trailer truck and the vessel. This was done to avoid connecting the truck directly to a moving vessel and additionally LH_2-hoses are very short to reduce heat influx and would probably not reach from the truck to the bunkering flange on the vessel. They suggest that loading arms, already developed for LNG can be extended to also be used as a bunkering stanchion for LH_2.

Figure 22: Mobile marine loading arm

Source: Wiese Europe

If not refuelled directly from the trailer truck, the LH_2 can also be offloaded into a local storage tank before bunkering. This can be a suitable solution if the vessel for example only uses 500 kg LH_2 a day and a once-a-week delivery of 4 tons provides the weekly fuel consumption. However, the double transfer can lead to a loss of up to 10 percent of the four tons from venting as transferring a cryogenic liquid from one tank to another adds heat and

103 CMR Prototech (2014)
104 Klebanoff et. al (2018)

causes vaporization[105]. In the table below Klebanoff and Pratt (2016) have estimated infrastructure cost for the two alternatives.

Table 8: Estimated cost for bunkering solution using pressure fill

Solution	*Piping and manifold*	*Permits and License fees*	*On-site storage tank (4,2 tons/LH_2)*	*Total*
Truck-to-vessel	770 000 USD	200 000 USD		970 000 USD
Tank-to-vessel	770 000 USD	200 000 USD	625 000 USD	1 595 000 USD

Bunkering is also possible with a ship-to-ship solution. Moss Maritime, in cooperation with Equinor, Wilhelmsen, Viking Cruises and DNV-GL, has developed a design for LH2 bunker vessel. According to Moss Maritime, the vessel has a cargo capacity of 9 000 m^3, 640 tons, and will provide LH2 bunkering services to merchant ships, in addition to open sea transport[106]. The total LH2 storage onboard the vessel shall enable delivery of minimum 500 tons of LH2 after laden voyage of maximum 25 days[107].

The cargo containment system shall consist of two 4 500 m^3 tanks. The LH2 bunker vessel will be loaded at a liquefication terminal, with the vessel berthed at a jetty. Offloading will take place in side-by-side mode to receiving vessels, or at a jetty if delivering to onshore receiving terminals. In their technical evaluation they find that for all critical equipment, with the exception of compressors and blowers for tank warming, potential vendors/manufacturers have confirmed that "existing equipment for LNG may be modified and adapted for LH_2 after further engineering and testing".

4.6 End users

The sections below highlight state-of-the-art projects with LH_2 among our three groups of vessels as well as some relevant vessels using compressed hydrogen and on-going projects.

Car ferry

Norway has 128 operating ferry routes, with most of them located in Hordaland, Møre & Romsdal and Nordland. The world´s first car ferry running on LH_2, will be put into operation between Hjelmeland and Nesvik on April 15th of 2021. The ferry will get a minimum of 50 percent of the energy supplied by LH_2 while the remaining energy need is provided by batteries.[108]. The plan is to refuel the ferry with 4 tons of LH_2 every other week. The ferry is operated and built by Norled, with LMG Marin, Westcon Power and Automation, Prototech, Ballard Power Systems and Linde Engineering as important partners. It not yet decided which shipyard will build the ferry which can hold 299 passengers and 80 cars[109].

[105] Pratt & Klebanoff (2016)
[106] Wilhelmsen (2019)
[107] Moss Maritime (2018)
[108] NCE Maritime CleanTech (2018)
[109] Norled (2018) and (2019)

Figure 23: World´s first LH_2 car ferry

Source: LMG Marin

High-speed craft

There are currently 96 routes for high speed crafts in Norway, with a diesel consumption of approximately 86 500 000 liters per year. This equals to 233 000 ton of CO2 emissions[110].

At least two hydrogen passenger vessels are in operation using compressed hydrogen: Hydroville in Antwerpen[111] (dual-fuel) and Water-go-round in San Francisco[112]. The team behind the Water-go-round-project sprung out of Sandia National Laboratories and have previously contributed to the SF-BREEZE project which examined the technical, regulatory, and economical feasibility of a high-speed passenger ferry powered by hydrogen fuel cells and LH_2 and its associated hydrogen fuelling infrastructure within the context of the San Francisco Bay. A vessel design was produced, and they did not reveal any insurmountable regulatory obstacles to deployment [113].

In Norway, five consortiums have signed a contract with Trøndelag County involving the development and demonstration of a zero-emission high-speed vessel with speed over 30 knots[114]. In figure 24 a design for one of the solutions, by Brødrene Aa in cooperation with Westcon and Boreal is shown. Also designs from consortiums led by Selfa Artic and Flying Foil, that have received support from the Pilot-E programme are included

[110] Selfa Artic (2016)
[111] Hydroville (2019)
[112] Water Go Round (2019)
[113] Pratt & Klebanoff (2016)
[114] Trøndelag Fylkeskommune (2019)

Figure 24 – Design for non-emission high-speed crafts

Source: From top: LMG Marin, Flying Foil and Brødrene Aa

Platform supply vessel

A platform supply vessel (PSV) is a ship specially designed to supply offshore oil and gas platforms and can accomplish a variety of tasks. While there are no LH_2-powered PSVs, fuel cells have been tested in an operational environment. In 2009, the Eidesvik-owned PSV Lady Viking had a 320 kW fuel cell installed, as a part of the research project Fellowship. The fuel cell provided energy both for systems onboard and propulsion, as part of a dual-fuel system. However, the fuel cell used natural gas and not hydrogen gas to convert the gas into electricity[115].

In 2014, a project led by CMR Prototech conducted a study of a hydrogen-PSV concluding that it would need LH_2 due to its higher density than compressed hydrogen. Using a PEM fuel cell with an efficiency of 54 percent, they estimated a daily need of ca 1700 kg/LH_2 and

[115] Maritimt Magasin (2009)

suggested either refuelling of 12 tons once a week or 6 tons twice a week, with a corresponding onboard storage need of 192 or 108 m^3[116].

Currently a cluster project by NCE Maritime Cleantech, Equinor and Wärtsila Ship Design is developing a concept for a hydrogen driven platform supply vessel that can serve the oil & gas industry in the North Sea. The energy system will be based on a combination of batteries and hydrogen fuel cells[117].

Other

Viking Cruises, a Norwegian shipping company, is working on a project for what could become the world's first cruise ship with zero emission technology. The ship will be around 230 meters long and fuelled by liquid hydrogen. It has a capacity to accommodate more than 900 passengers and a crew of 500. According to the Norwegian Maritime Authority, Viking Cruises has been in dialog with Equinor on delivery of hydrogen[118].

Royal Caribbean Cruises Lines has previously presented the energy consumption for a large cruise ship and what it would need of hydrogen supply. They estimate about 240 MWh for hotel and 240 MWh for propulsion per day – a combined 480 MWh of energy per day. According to their calculations a battery solution would have a weight of at least 6200 tons and a size of 10 000 m^3. If the same energy consumption is covered by hydrogen, they estimate about 30 tons of hydrogen per day and a need for 6000 m^3 of storage for two weeks of fuel autonomy. With a density of 71 kg LH_2/m^3 that gives a total hydrogen need of 426 tons for a two week stretch[119].

Another example is the work done by the Norwegian shipowner Havila for preparing their new ships operating the coastal route (Kystruten) from Bergen to Kirkenes. They have recently received over 100 million NOK to further research a fuel cell solution that can enable the vessels to operate in non-emission zones, such as World Heritage Areas[120].

In the US, a design for a hydrogen-driven research vessel was presented in 2018. The Zero-V has 10 900 kg of consumable LH_2 stored in two tanks, for parallel refuelling, and a range of 2400 nautical miles[121].

The Norwegian support scheme Pilot-E has also supported a smaller containership called Seashuttle that will use compressed hydrogen[122].

4.7 Energy efficiency throughout the value chain

The hydrogen value chain has energy losses from energy input in the production phase to the efficiency of the powertrain onboard the end user. Through a literature review we have estimated the energy efficiency from production to propeller for both electrolysis and gas reformation with carbon capture.

According to IRENAs latest report an alkaline electrolyser today has an energy use of 51 kWh/kg gaseous hydrogen, giving it an efficiency of 65 percent. A liquefaction plant like Lindes Leuna facility with an energy use of 11,9 kWh/kg LH_2 has an efficiency of about 74

[116] CMR Prototech (2014)
[117] NCE Maritime CleanTech (2019)
[118] Norwegian Maritime Authority (2017)
[119] Royal Caribbean Cruises (2018)
[120] Sintef (2018b)
[121] Klebanoff et. al (2018)
[122] Teknisk Ukeblad (2019a)

percent[123]. With a total energy input of 63 kWh/LH_2 and a lower heating value of 33,3 kWh/kg LH_2, the energy efficiency to produce 1 kg LH_2 is 52 percent.

When produced through gas reformation the estimated energy needed to produce 1 kg of gaseous hydrogen with carbon capture is 48 kWh/kg, with 11,9 kWh/kg for liquefaction. Thus, the energy efficiency of the production phase is 55,5 percent, slightly better than by electrolysis.

During storage and distribution multiple sources estimate a boil-off between 0,2 and 0,5 percent per day. IEA report a boil-off stream of 0,3 percent for liquid tankers for hydrogen delivery, while US Drive estimate 0,5 percent for liquid distribution tankers and a very low evaporation rate for large storage. The NASA LH_2 tank at Cape Carnaval has a reported evaporation loss of 0,03 percent per day for storage over multiple years.

US Drive also report a loss of up to five percent when unloading the LH_2 to vessel/local storage[124]. This is higher than what has been reported by developers/suppliers during the work of this report, which indicate that bunkering with a minimum of losses, towards 1 percent is plausible. As a conservative measure, we have used the 0,3 percent loss for storage/distribution and 5 percent in the bunkering phase. Boil-off during storage on board the vessel is also a potential loss, but according to Air Liquide there are several options to permanently re-use boil of gas and thus eliminate the loss[125] or technology that increase the maximum holding time without boil-off[126].

Lastly, with an estimated efficiency of 50 percent for the fuel cell about 16 kWh of the input energy reach the propeller – thus the complete energy efficiency of the value chain is around 25 percent when produced by electrolysis and 26,5 percent when produced by gas reformation and carbon capture, see appendix for calculations.

The energy losses in kWh are visualized in the next figures.

[123] Efficiency = LH_2 LHV / (LH_2 LHV + Liquefaction Energy)
[124] IEA (2015), US Drive (2013)
[125] Air Liquide (2015b)
[126] Linde (2014)

Figure 25: Energy losses from production to propeller – Electrolysis

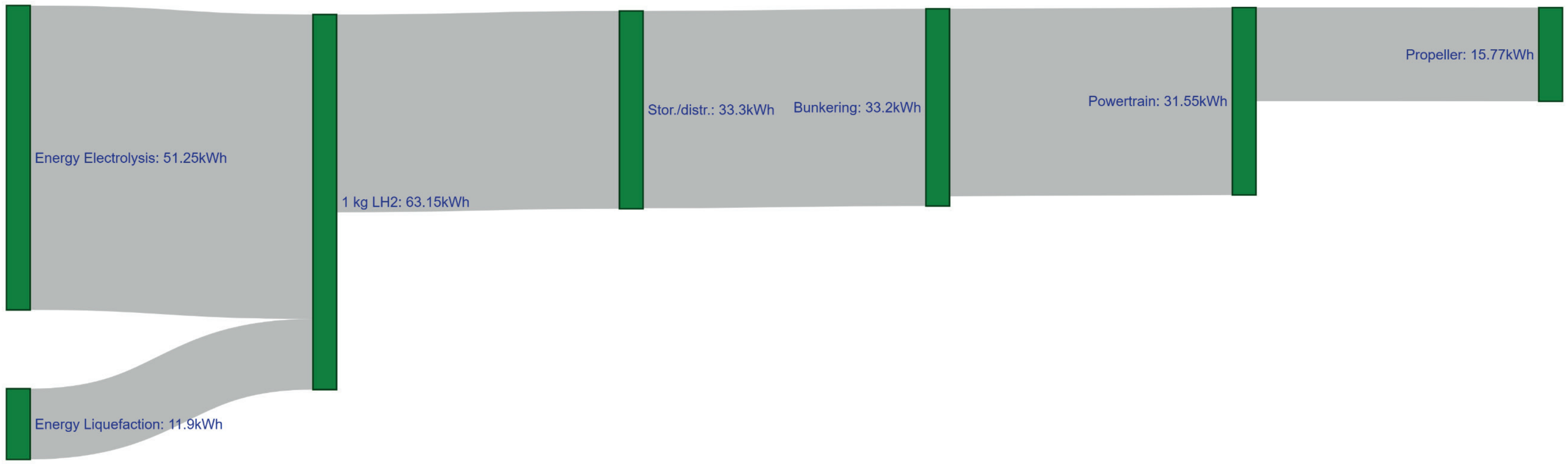
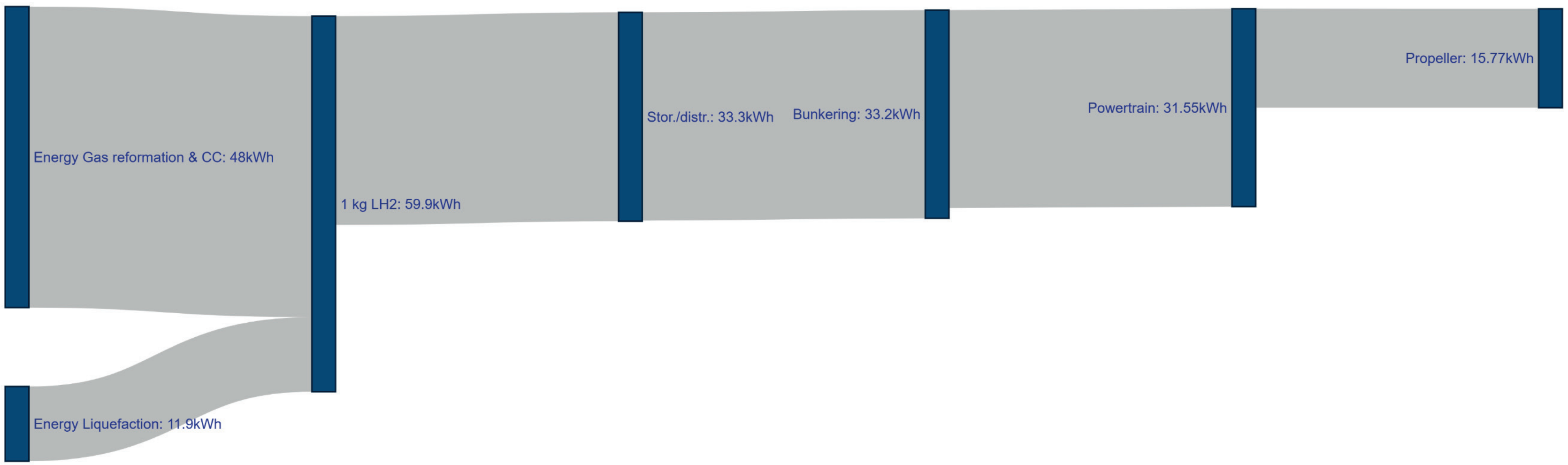


Figure 26: Energy losses from production to propeller – Gas reformation with Carbon Capture



5. Regulations, standards and codes for liquid hydrogen

In the following chapter we will examine the status quo for regulations, standards and codes for the different parts of the value chain presented in figure 7. We will concentrate on the land-based operations and not go into detail for onboard solutions.

For the vessels, the leading regulation is International Code of Safety for Ships Using Gases or other Low-Flashpoint Fuels (IGF Code) – Part A: 2.3 Alternative design which provides guidelines for the use of fuels not explicitly mentioned in the code. By demonstrating that functional requirements are met, and risk assessments carried through one can demonstrate that the alternative solution is as safe as a conventional fuel. A draft version of a new part E for fuel cells has been discussed[127]. For further study on the use of hydrogen onboard vessels we refer to DNV-GLs study on the use of fuel cells in shipping for the European Maritime Safety Agency or Sandia National Laboratories report on hazardous zones for on-board maritime hydrogen liquid and gas systems[128].

Some international regulations with a wide impact area, such as Pressure Equipment Directive (PED) and ATEX may apply throughout the value chain. In the following paragraphs we emphasize regulations, standards and codes that are relevant in a Norwegian context for end users of infrastructure.

Production of hydrogen

The relevant municipality is responsible for permitting requirements for facilities with a production/tank capacity for storing up to 5 tons of hydrogen. While there are no regulations made specifically for hydrogen the *Act on protection against fire, explosion and accidents with dangerous substances* with its underlying regulations on the handling of dangerous substances address among other aspects planning, construction and production of liquid and gaseous fuels[129]. It also addresses the need for risk assessments and safety zones around the production facility, especially to protect third parties.

Instead of fixed generic safety distances, it is customary to use a quantitative risk assessment to examine the risk contour based on the parameters for each individual case and achieve a more flexible approach to safety zones. If the amount of hydrogen produced/stored onsite exceeds five tons consent must be given from the Directorate for Civil Protection and follow the Major Accident Regulation with additional duties and responsibilities.

On an international level the ISO/TC 220 mainly addresses the use of gaseous hydrogen[130], while the recently established working group from the European Committee for Standardization (CEN) on hydrogen in energy systems has yet to publish any standards and does not include transport and storage of liquid hydrogen[131].

[127] Morelos (2017)
[128] DNV-GL (2017) and Blaylock et.al (2018)
[129] Lovdata (2002) and (2009)
[130] ISO (2019)
[131] CEN (2016/2019)

Storage of hydrogen

The Norwegian acts and regulations described in the previous subchapter also applies for storage of hydrogen, even if storage is at a different location than production, for example through centralized production and local storage at the quay. Installations harbouring more than 5 tons of hydrogen must apply for special consent from the Directorate for Civil Protection.

Internationally, storage is perhaps the part of the value chain that is best covered, as both the European Industrial Gases Association (EIGA), ISO and CEN have published on the use of cryogenic tanks/vessels as a mean of storage. The EIGA document 06/19 for example give principles on layout and location of installations, access to site, testing and commissioning and general advice on safety distances[132]. The guideline from the Directorate for Civil Protection on facilities for use of liquid and gaseous fuels[133] defines safety distances for LNG tanks which has been communicated could serve as an indication, but the exact distance and zones requiring special consideration is determined through a risk analysis on a case-to-case basis.

Distribution by ship

Distribution by ship can be done in two different ways, either in dedicated LH_2-transporters such as the examples highlighted from Moss Maritime and Kawasaki, or in containers with cryogenic tanks on ro-ro-ferries, like Air Products transport LH_2 from their facility in Rotterdam. The Norwegian Maritime Authority point to the International Maritime Organization (IMO) for regulations[134]. The IGC code covers the construction and equipment of ships carrying liquefied gases in bulk while the IMDG covers the carriage of dangerous goods in packaged form. Here, the requirements for both compressed and refrigerated liquid hydrogen are comparable to those for natural gas.

However, the International Gas Carrier Code (IGC Code) lacks specific requirements for hydrogen. Thus, the HyLaw-project, an EU-project gathering cross-national data on hydrogen regulations and standards, highlights maritime transport as an area where “adjustment of legal framework is needed, in order to provide clear and predictable conditions for technology and market development”[135]. To address this regulatory gap, IMO adopted a set of interim recommendations for carriage of liquefied hydrogen in bulk (resolution MSC.420(97) under in November 2016. According to HyLaw, under the IGF Code it is anticipated that initial restrictions regarding storage quantities and locations will be put in place for hydrogen (e.g. storage on top deck).

As of now the national regulation on maritime transport of dangerous goods sets a limit to the number of ADR-units on the same vessel. The maximum number of ADR-regulated units is four on an open ro-ro deck and two on a closed ro-ro deck. However, flammable gases are not allowed on closed ro-ro decks, making open deck vessels the only option for hydrogen transport [136].

Distribution by truck

The ADR directive provides regulation for transport by truck in addition to regulations related to the container systems. Currently the most common transport method in Norway is compressed hydrogen at 200 bars, with an upper limit for composite cylinders at 520 bar. In terms of hydrogen amount,

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132 EIGA (2019)
133 DSB (2015)
134 Conversation with the NMA 21.nov 2018
135 HyLaw (2018)
136 Lovdata (2010)

there is no upper limit in Norway, but the weight of a truck with trailer cannot exceed 50 tons and a length of 19,5 meters[137].

In accordance with ADR tank transport of hydrogen is forbidden in tunnels of category B,C,D end E. In Norway this applies to the subsea tunnel between Ellingsøy and Valderøy, near Ålesund between 0600-2400 and Hvalertunnelen where transport of dangerous goods needs permission from the Road Traffic Central[138].

Bunkering

While there are protocols and codes for hydrogen refuelling stations, there is a regulatory gap for maritime bunkering of liquid hydrogen. In the guidelines to the Regulation on handling of dangerous substances it states that hydrogen to a large extent is comparable to LPG and CNG and that hydrogen fuelling stations shall be designed and constructed according to ISO/TS 20100 Gaseous hydrogen – Fuelling stations (later replaved by ISO/TS 19880-1:2016)[139].

Perhaps as a better comparison for LH_2, the guideline also includes a chapter on
on maritime bunkering of LNG, which serves as a useful comparison for LH_2, and defines important parameters such as necessary risk assessments, safety zones, bunkering procedure, coupling solutions/break away and layout on the quay. For fuelling of a passenger vessel, a special consent – *"samtykke"* is needed from the Directorate of Civil Protection. For these instances a quantitative risk assessment is required to set safety zones around the bunkering facility[140].

[137] Correspondance with Arne Lærdal, Directorate for Civil Protection, April 2019 and Lovdata (2014)
[138] HyLaw (2018)
[139] DSB (2018)
[140] Correspondence with DSB

Table 9: Summary of relevant regulations, standards and codes[141]

Step of value chain	*Norwegian*	*International*
Production	• The Planning and Building Act • Act on protection against fire, explosion and accidents with dangerous substances • Regulation on handling of dangerous substances • Major Accident Regulation	• ISO/TC 197 (gaseous) • CEN-CLC/JTC 6 (under establishment)
Storage	• Act on protection against fire, explosion and accidents with dangerous substances • Regulation on handling of dangerous substances • Major Accident Regulation	• EIGA: Documents 06/19, 114/09, 119/04, Technical Bulletin 27/18 and 11/14 • ISO/TC 220: Cryogenic Vessel • CEN/TC 268: see website for several standards
Distribution by ship	• Ship Safety and Security Act • Regulation on maritime transport of dangerous goods • Regulation on bulk transport of dangerous substances	• IMO: IGC and IMDG codes • EIGA Documents 06/19, 41/18 • CEN/TC 268: see website for several standards • IMO: Resolution MSC. 420(97)
Distribution by truck		• UNECE ADR • EIGA 06/19 • CEN/TC 268: see website for several standards • ECE Regulation 67 rev.2, 110 rev. 12, 115 or 79/20094 or 406/20105 (container systems)
Bunkering	• Act on protection against fire, explosion and accidents with dangerous substances • Regulation on handling of dangerous substances	• No standard for maritime bunkering of LH_2, several for gaseous refueling of land-vehicles: SAE J2601, ISO TC197 etc

141 Based on Hamanaka (2015) with additional information from conversations with the Norwegian Directorate for Civil Protection, Norwegian Maritime Authority and research from the HyLaw-database

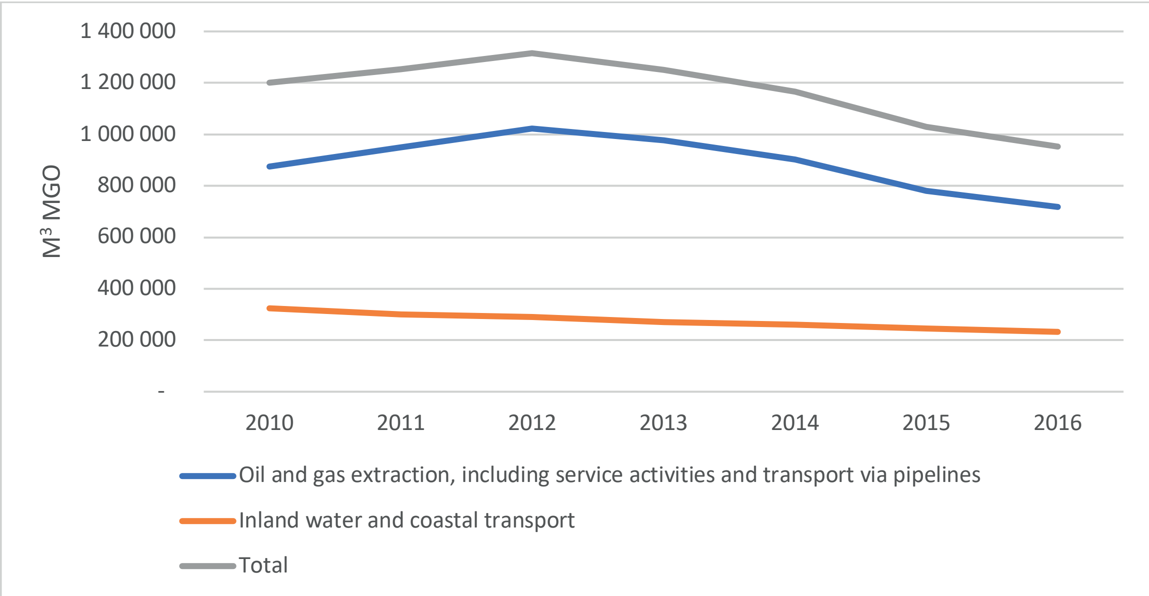
6. Marine bunkering today

The great majority of the vessels[142] in question for this study use Marine Gas Oil (MGO) as fuel, with a few using Liquid Natural Gas (LNG). On a national level the sale of MGO to the oil and gas sector and inland water and coastal transport decreased in the period from 2012 and onwards[143].

In 2016 the consumption to the oil and gas sector was just below 720 000 m^3 of MGO. It is important to note that figure includes both use on offshore installations and fuel for supply vessels. Within inland water and coastal transport, the consumption was just above 230 000 m^3 in 2016.

There are no official statistics for the use of LNG, however the NGO Energigass Norge estimated in 2015 the annual Norwegian market to be about 260 000 m^3 / 1,6 TWh[144]. In an updated analysis based on AIS-data, DNV-GL estimated the annual consumption of LNG in Norwegian waters to be 145 000 tons / 2,1 TWh[145].

Figure 27 – Annual consumption of Marine Gas Oil – m^3 [146]



While the statistics for annual consumption of MGO is derived from the national energy account and is not available at county-level, the registered sale of MGO shows that the western counties by far is the largest market.

[142] Car ferries, high speed crafts and platform supply vessels
[143] Statistics Norway (2019)
[144] Energigass Norge (2015)
[145] Norwegian Environment Agency (2018) Kunnskapsgrunnlag for omsetningskrav i skipsfart, report M1125, http://www.miljodirektoratet.no/Documents/publikasjoner/M1125/M1125.pdf , last visited 31th of January 2019
[146] Statistics given in weight, converted to m^3 by using a density of 855 kg/m^3

Table 10 – Sale of MGO to sea transport in 2016, by county[147]

Country	*Amount in m3*	*Percentage of total*
Rogaland	21 280	7 %
Hordaland	65 018	22 %
Sogn og Fjordane	52 145	17 %
Møre og Romsdal	19 209	6 %
Sør-Trøndelag	12 003	4 %

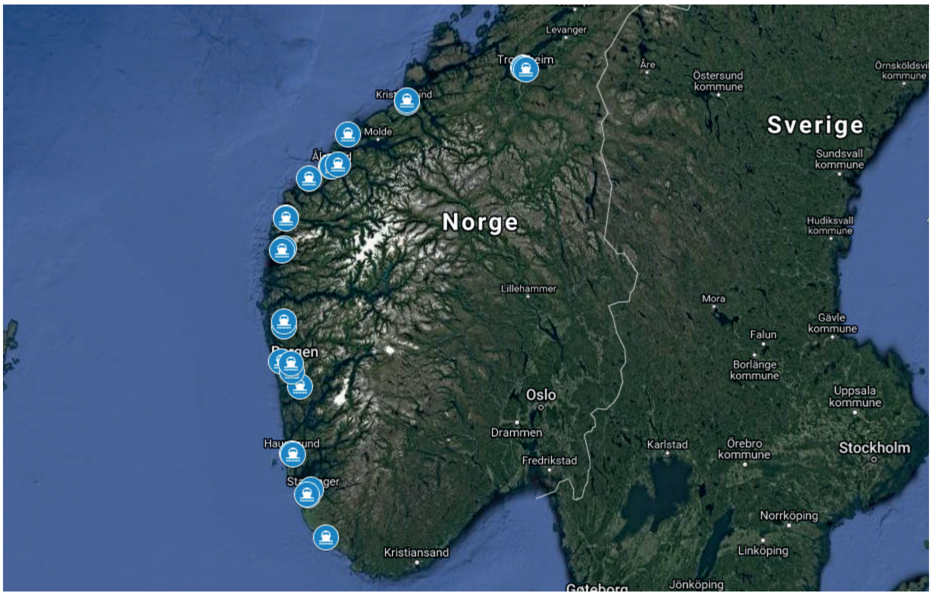
The table above does not include MGO-sale to platform supply vessels, as Statistics Norway do not present detailed enough categories to extract those numbers on the county level from a broader category covering both on- and offshore industries. Hence the actual use of MGO by county would be higher than given in table 10, especially for Rogaland and Hordaland.

The number of fuel suppliers is limited to a small number of large players, with Circle-K having over 50 percent of the market. The suppliers deliver both to end-customers and distributors of fuel, such as Bunker Oil who operate their tanking facilities and bunkering vessels along the coast.

Table 11 – Main suppliers of MGO[148]

	2016	***2017***
ST1 Norge	21,5 %	26,9
Esso Norge	15,4 %	14,6
Circle-K	57,4 %	48,2
UNO-X Gruppen	5,8 %	0,1
Others	0,1 %	10,2

Figure 28 – Major bunkering sites in Western Norway



The suppliers normally have three types of storage solutions[149]:

- Main storage or terminals with most products available, and normally supplied by boat from a refinery

[147] Statistics Norway (2018)
[148] Data supplied by Drivkraft Norge
[149] Drivkraft Norge, quoted in Energigass Norge (2015)

- Distribution storage, supplied by boat from a refinery or from a main storage facility
- Coastal storage facility – often run by independent operators

In addition, you also have larger storage solutions at services- and logistics ports for the oil and gas industry.

The refuelling of vessels is normally done from permanent fuelling facilities or delivered to the ship by a bunkering vessel or truck, depending on the vessel type and current route.

The table below is a non-exhaustive list of bunkering sites along the coastline but shows the storage capacity of MGO and LNG and location for the largest facilities. In addition, we have estimated the necessary volume if the same energy amount represented by MGO and LNG is to be replaced by liquid hydrogen. Due to the higher energy density in MGO and LNG, as shown in table 4, the volume storage needed is significantly larger with LH_2.

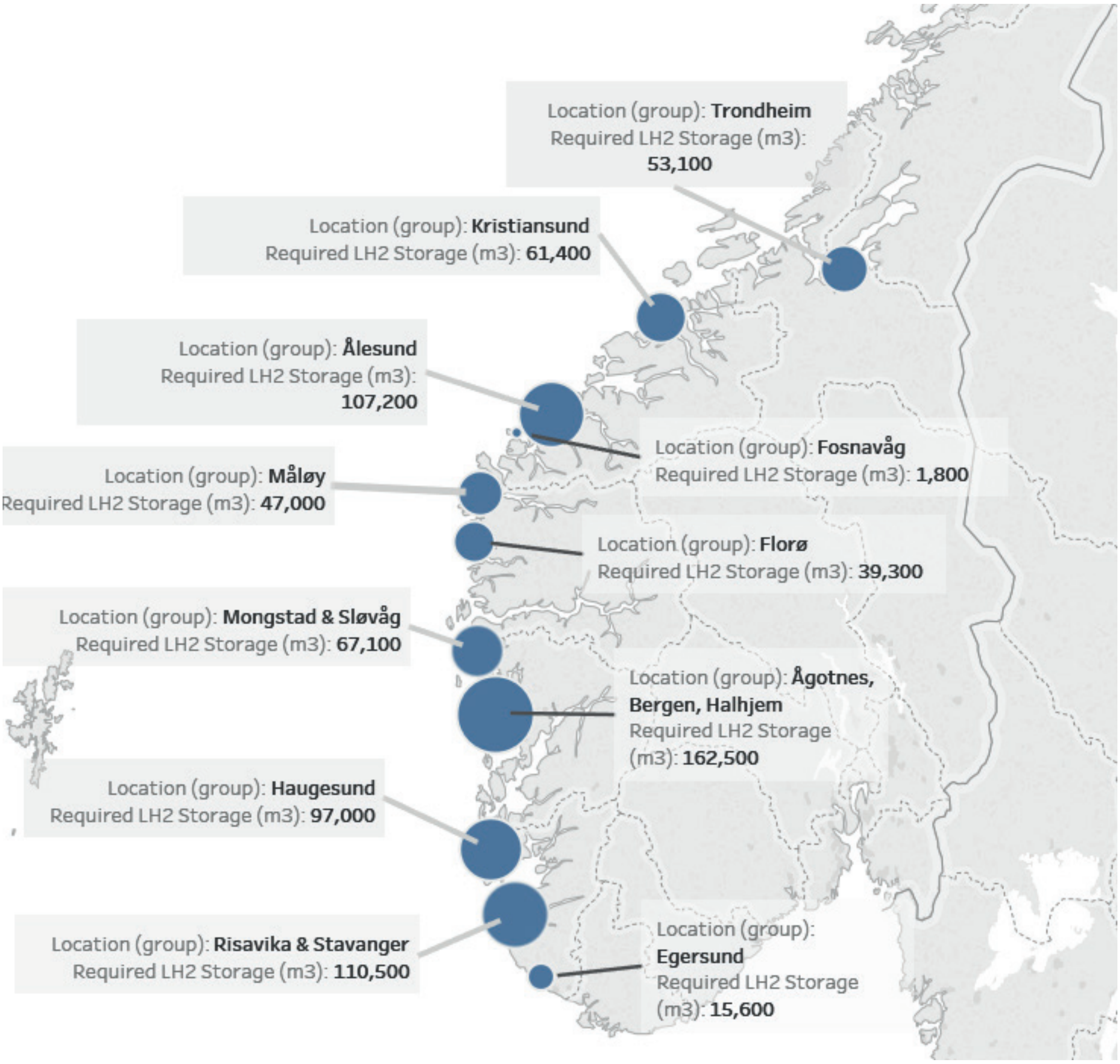
Table 12: A selection of marine bunkering sites Marine Gas Oil (MGO) and Liquified Natural Gas (LNG)[150]

Location	*Operator*	*Used by*	*Storage capacity (m3)*		*Storage capacity needed if LH2 (m3)[151]*
			MGO	**LNG**	**LH2**
Egersund	H.E. Seglem & Sønner	Bunker Oil	3 500		15 600
Stavanger	Norsea AS	Circle-K	7000		31 300
Stavanger	Norsea AS	Circle-K / Esso / Shell	7000		31 300
Risavika	Skangas	Skangas	0	30 000	77 600
Haugesund	L Storesund & Sønner	Circle-K / Bunker Oil	11 000		49 200
Haugesund	Shell	Shell / Esso	10 700		47 900
Ågotnes	CCB	Circle-K / Gasnor	9 900	500	45 600
Mongstad	Mongstadbase	Circkle-K / Gasnor	9 000	1 000	42 800
Bergen	Esso	Shell / Esso/Bunkeroil	16 000		71 500
Halhjem	Gasnor	Gasnor	0	1 000	2 600
Sløvåg	Bunker Oil	Bunker Oil	15 000		67 100
Florø	Sundfjord Drift / Saga Fjordbase	Circle-K / Gasnor	7 000	500	32 600
Florø	Florø Bil og Havneservice	Bunker Oil	1 500		6 700
Måløy	Brødrene Tennebø	Circle-K / Bunker Oil	3 800		17 000
Måløy	MH24		6 700		30 000
Ålesund	MH24		5 500		24 600
Ålesund	Shell	Circle-K / Esso / Shell	6 000		26 800
Ålesund	Bunker Oil	Bunker Oil	0	21 560	28 700
Kristiansund	Norsea AS, Vestbase	Circle-K / Gasnor / Uno-X	13 000	400	59 200
Kristiansund	Atlantic Bunkers	Bunker Oil	500		2 200
Fosnavåg	MH24		400		1 800
Trondheim	Esso	Shell / Esso	11385[152]		50 900
Trondheim	Statoil	Circle-K	500		2 200

[150] Based on input from Energigass Norge (2014) and input from the various operators and fuel companies
[151] Storage capacity found by using the following energy densities (MJ/m^3): MGO 38000 MJ/m^3, LNG 22000 MJ/m^3 and LH_2 8500 MJ/m^3
[152] Gas oil, but used for maritime fuel

In figure 29 we have grouped together the information from table 12 on a regional level. While this is a simplified presentation of the geographical aspect, it gives a perspective on how much storage capacity is needed to store the same amount of energy in LH_2.

Figure 29: Regional storage needs for LH_2



6.1 Alternative zero-emission fuels to LH_2

By 2050 DNV-GL estimates that 39 percent of maritime fuel will be carbon-neutral. In addition to hydrogen, several other energy carriers, such as ammonia, bio-diesel and methanol, have the potential to be carbon-neutral fuels if produced without emissions[153].

Ammonia is particularly interesting as it contains 18 weight percent hydrogen and is an integral part of the hydrogen market, using nearly half of the current global hydrogen production. With a density of 653.1 kg/m^3 ammonia contains more hydrogen than a cubic meter of liquid hydrogen. It can also be used directly in fuel cells with the most efficient technology being high-temperature Solide Oxide Fuel Cells (SOFC)[154]. They can achieve an efficiency of over 60 percent[155] but are a more immature large-scale technology than alkaline or PEM fuel cells.

MAN Energy Solutions has recently introduced the development of a dual-fuel engine running on ammonia in combination with liquid petrol gas. According to the company the two-stroke engine design is suitable for large ocean-going vessels, including tankers, bulk carriers, and container ships, with engine sizes from 5 to 85 MW. They estimate a development time of 2-3 years a development cost of 5 MEUR and an expected efficiency of 50 percent[156].

The advantages for using ammonia as a maritime fuel is an already existing infrastructure with most of the value chain illustrated below already in place up to the point of bunkering to maritime end-users. According to Statkraft, the energy needed to produce ammonia, in addition to the energy to produce the hydrogen used as input, is about 10-12 kWh/kg NH_3[157] or equal to the kWh/kg used to liquify hydrogen. With a higher density of hydrogen per cubic meter than liquid hydrogen, it can be a cost-efficient alternative in terms of fuel price only. It also just needs to be cooled down to minus 39 degrees Celsius under atmospheric pressure to obtain a liquid form, which is far less than LH_2, making it easier to handle. Among the disadvantages, ammonia is highly toxic, and the corrosive effect is a problem that needs to be addressed. For example, copper and zinc corrode rapidly in contact with ammonia.

Ammonia can be transported either by truck, railway or by ship. If transported by truck, the transports are limited to maximum 36 tons due to weight restrictions on the highway. The capacity of a tank ranges from approximately 13 000 litres to 57 000 litres. Most units typically range from approximately 30 000 to 45 000 litres[158].

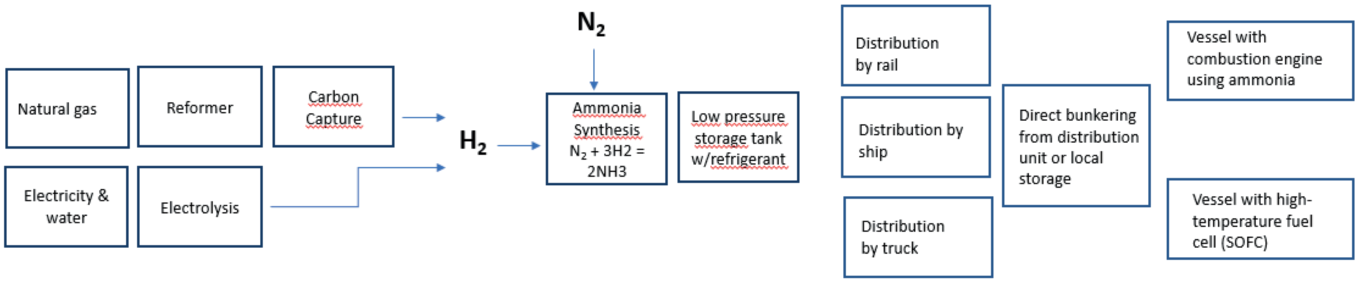
The second way of transport is by rail where about 70 percent of the hazmat moves in tank cars. Tank cars transporting anhydrous ammonia are pressure tank cars, typically DOT Class 105 and 112. The capacity of these cars is approximately 130 600 liters[159].

When transporting ammonia by sea, it is usually transported in a fully refrigerated ship or a semi-refrigerated liquefied petroleum gas (LPG) carrier. A fully refrigerated ship has a capability of carrying 15 000 to 85 000 m^3 gas and is best suited for long voyages. A semi-

153 DNV-GL (2018)
154 Afif et.al (2016)
155 Fuel Cell Today (2019)
156 MAN (2018)
157 Statkraft (2018)
158 Transcaer (2004)
159 Transcaer (2004)

refrigerated ship has a capacity of transporting up to 5 000 m^3 gas and are light weighted compared to fully pressurized ships[160].

Figure 30: Value chain for ammonia



Biodiesel is the most promising biofuel for ships and is suitable for replacing marine diesel oil or marine gas oil. The density is 860 kg/m^3 compared to 890 kg/m^3 for MGO, a more significant difference is to be seen from the comparison with LH2, where the density is 70.85kg/m^3.

It can be produced from agricultural crops and residues, energy crops, forest residues and waste, but does not reduce carbon emissions directly. Bio-CO_2 is traditionally considered to be part of the CO_2 that would otherwise circulate within the natural cycle and is therefore often categorised as carbon neutral. From a lifecycle perspective the greenhouse gas emissions (GHG) is assumed to be about 50 percent less than for conventional diesel[161].

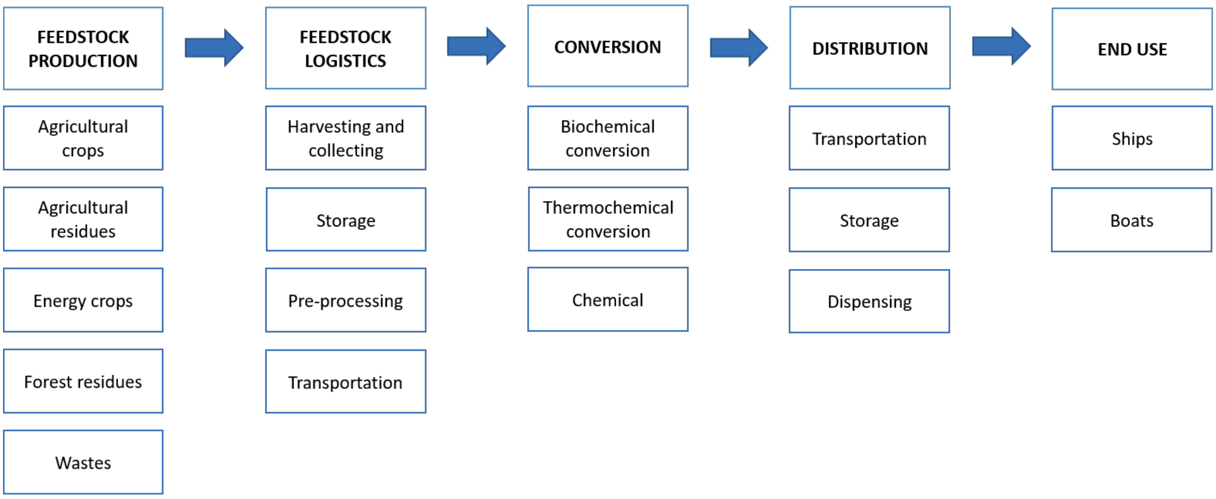
There are three different methods for converting biomass to biodiesel; thermal conversion, chemical conversion and biochemical conversion. The energy content of biodiesel is 11.80 kWh/kg compared to 33.3 kwh/kg for LH2.

Hydro treated vegetable oils (HVO) is high-quality biodiesel where the oxygen is removed using hydrogen, which results in long-term stability. The fuel is compatible with existing infrastructure and can also be used in existing engines[162]. Biodiesel can be used alone or blended with petrodiesel.

First generation biofuel such as vegetable oil-based biofuel can typically compete with fossil fuels at oil price round 60 USD/barrel. Second generation biofuel that is younger and less optimised needs oil prices around 100 USD/barrel to be competitive[163].

[160] Marine Insight (2016)
[161] DNV GL (2018)
[162] DNV GL (2018)
[163] IEA Bioenergy (2017)

Figure 31: Value chain for biofuel



Methanol, CH_3OH is four parts hydrogen, one-part oxygen and one-part carbon, making it the lowest carbon content and the highest hydrogen content of any liquid fuel. It can be produced from several different resources, like natural gas or coal, or from renewable resources such as biomass and green[164] hydrogen. The most common feedstock for the industrial process is oil or natural gas. The density of methanol is the same as for biodiesel, 780 kg/m^3.

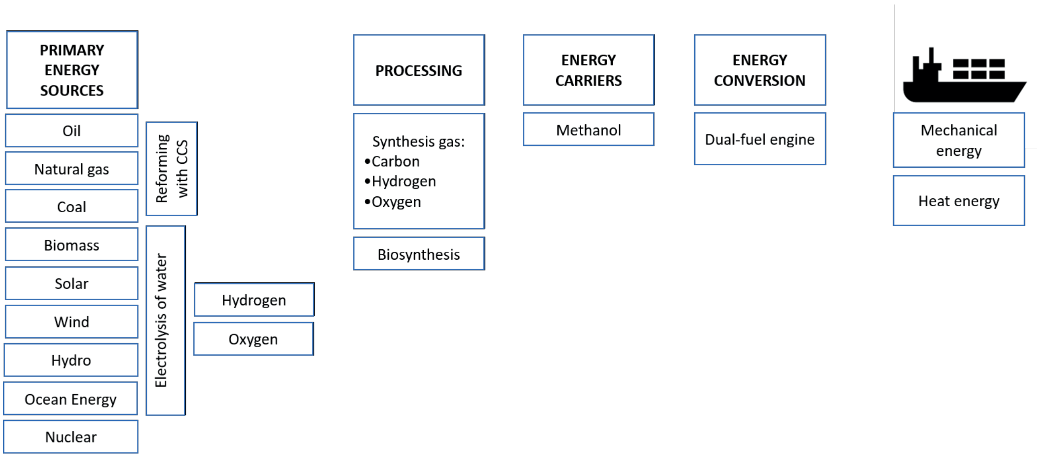
In this case, where methanol is an alternative zero-emission fuel to LH2, it must be produced from green hydrogen. Methanol production from green hydrogen includes a carbon source, which needs to be included in a renewable life cycle in order to define it as carbon neutral.

On the global market, the price of a kg renewable methanol is approximately 0,8 euro, which gives a price of 40 NOK per kg hydrogen[165]. The energy content of methanol is 5.56 kWh/kg which is far less that hydrogen's 33.3 kWh/kg, the density however, shows 780 kg/m^3 for methanol versus 70.85 kg/m^3 for liquid hydrogen.

Methanol is transferred in chemical tankers with an estimated price of 15-40 USD/ton, depending on distance and size of the ship[166]. It can be stored in tanks designed for diesel and other highly flammable hydrocarbons under atmospheric pressure and does not require cooling. Methanol fuel tanks are often twice the volume of oil tanks with the same energy content[167].

[164] Green hydrogen is produced from electrolysis with renewable energy as input, or from natural gas reforming with CCS.
[165] Statkraft (2018)
[166] Statkraft (2018)
[167] DNV-GL (2018)

Figure 32: Value chain for methanol



6.2 Price comparison between fuels

Looking at the price of hydrogen in a vacuum is not very useful, and another way to address the question is to find a price level that is competitive with other types of fuels. Prices for liquid hydrogen are based on market availability and produced by gas reformation without CCS, while the compressed hydrogen is produced by electrolysis.

In table 13 we have compared current prices for hydrogen to other current maritime fuels and future alternatives. The prices are all for fuel delivered at or near the end user.

We only consider fuel cost and do not include capital expenditure in vessels or varying level of other operational costs.

Table 13 – Price comparison

Fuel	*Retail price EUR/kg (ex. vat)*[168]	*Calorific value (kWh/kg)*	*Spec. fuel Consumption (g/kWh)*	*Efficiency powertrain*	*Cost in EUR per kWh*	*Corresponding LH_2-price EUR/kg LH_2*
LH_2 Norway	15,4	33,3	60,1	50 %	0,92	**N.A.**
LH_2 Europe	7,1	33,3	60,1	50 %	0,43	**N.A.**
LH_2 US	5,4	33,3	60,1	50 %		**N.A.**
CH_2 (250 bar) Norway	10,2	33,3	60,1	50 %	0,61	**10,2**
MGO	0,61	11,97	185,6	45 %	0,11	**1,9**
Bio-diesel	1,68	10,20	188,3	45 %	0,32	**5,3**
LNG	0,76	12,50	177,8	45 %	0,14	**2,3**
LPG	1,10	12,90	172,3	45 %	0,19	**3,2**
Ammonia (fuel cell)	0,51	5,17	193,4	55 %	0,18	**3,0**
Ammonia (combustion)	0,51	5,17	193,4	50 %	0,20	**3,3**
Methanol	0,8	6,39	313	50 %	0,25	**4,2**

[168] Prices are based on the industrial knowledge of the project partners and information from suppliers. The price of Ammonia is gathered from ISPT (2017). Some prices are converted from NOK to Euro with a conversion rate of 9,84 EUR/NOK

In the current market, hydrogen is far from competitive with fossil fuels. The current merchant price of LH_2 delivered in Norway is more than eight times higher in Euro/kWt than marine gas oil. But there is room for price reductions.

If we use the price given by Air Products for LH_2 ex. works in Europe at 7,1 Euro/kg LH_2 the price difference is reduced to nearly four times as expensive. While the price for LH_2 delivered on-site in California for the SF Breeze-project could be as low as 5,4 Euro/kg, comparable to that of bio-diesel prices in Norway. The price difference is probably due to larger liquefaction plants in the US than the 5 tons per day facility of Air Product in Rotterdam.

Ammonia is also a possible non-emission energy carrier, which already has an established value chain. The price of ammonia today varies between 300-350 dollar per ton, but this is ammonia produced with hydrogen from gas reformation without CCS. In their study of ammonia as an energy carrier for Svalbard they estimate a price of 5000 NOK per ton from small production plants based on electrolysis from renewable energy. The price for methanol is collected from the same study and is also based on hydrogen production from electrolysis.

Still, ammonia is a cost-effective option from a fuel perspective, but we emphasize that we do not consider the cost/maturity of vessels and powertrains using ammonia. To utilize directly in a fuel-cell the ship needs a high-temperature Solide Oxide Fuel Cell which is less mature than alkaline and PEM fuel cells. Alternatively, engine producer MAN Energy has recently released the first dual fuel-engine combining diesel and ammonia as fuel[169].

6.3 Price development for liquid hydrogen

As seen in table 13 there is a wide price gap from LH_2 to commonly used fuels such as MGO and LNG today. Predicting a future price depends on several variables: production volume, capital cost, efficiency levels, energy cost for natural gas and electricity, distribution and for gas reformation also the cost for carbon capture and storage.

Today, hydrogen produced from gas reformation is cheaper than hydrogen produced from electrolysis, but as the latter value chain mature, the price gap is expected to decrease[170], especially with an added cost of carbon capture and storage, which according to IEAGHG (2017) increase CAPEX with 18-79 percent and OPEX with 18-33 percent.

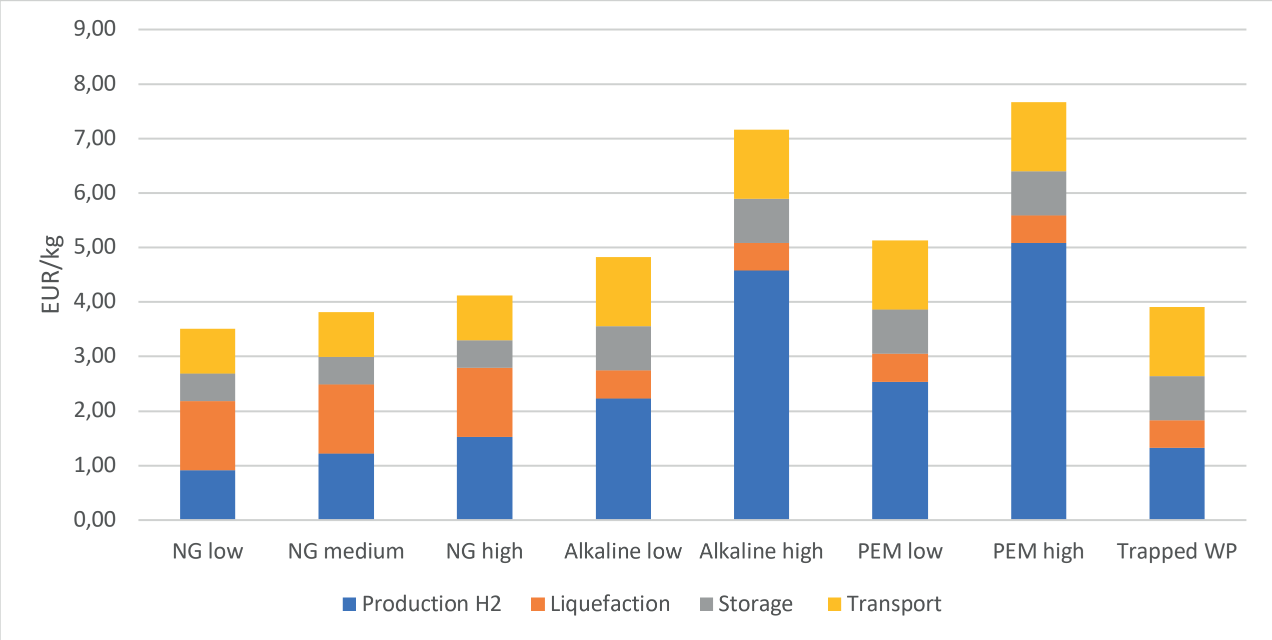
Concentrating on development in Norway we have separate estimations from DNV-GL on production from gas reformation with CCS and electrolysis in 2030, as well as cost for liquefaction, storage and transportation[171]. In addition, a scenario with “trapped” wind power from Northern Norway is estimated to have an electricity price below 0,20 NOK/kWh. In their analysis they use an electricity price between 0,34-0,67 NOK/kWh ex vat and a gas price between 1,70-2,20 NOK/Sm^3.

Other input is an efficiency of 75 percent for liquefaction, 15 days of storage before transport and 1000 km transportation by bunkering ship.

Combing the input and these parameters shows a price range from 3,5-7.7 EUR/kg LH_2 depending on the cost of energy input and fall of capital cost, the latter mostly affecting production from electrolysis.

[169] Man Energy (2018)
[170] See for example Energy.gov (2015), IRENA (2018), DNV-GL (2019) for a review of expected cost reductions
[171] DNV-GL (2019)

Figure 33: 2030: Estimation of LH_2-cost in Norway[172]



Using the same parameters as in table 13 we compare the 2030 price per kg LH_2 with other fuels, we see that LH_2 as a fuel can compete with current bio-diesel prices and ammonia in terms of fuel cost alone.

In the scenarios above, the hydrogen is distributed by ship. By using a standardized formula for various distribution units developed by the Institute for Transport Economics it is possible to get an understanding of land-based transportation. The formula considers time and km-cost for transport but does not consider investment cost for distribution units. But it can be used to assess how much distance affects the transportation cost by trailer.[173].

We have used the formula to calculate whether transport from Tjeldbergodden or Kvinnherad, two known project sites, is best served to supply a need of 4 tons in Florø, assuming similar investment cost for trailer and storage tank. Despite the distance/time being higher from Tjeldbergodden and twice the number of ferry crossings, the difference between the two alternatives are only about 1,50 NOK/kg LH_2 in favour of the closer alternative in Kvinnherad (see appendix for calculations). This gives an indication that the total cost for LH_2 is much more sensitive to the production price than transportation cost. In line with calculations based on US data which attributes 16,4 percent of the total LH_2 cost to transport[174]:

[172] Combination of data from DNV-GL (2019)
[173] Grønland (2018). The km-cost covers salaries, capital cost, annual fees, insurance and administration. The time cost covers: maintenance, fuel, washing tires and other supplies
[174] Klebanoff & Pratt (2016) – Production 38,5 percent, Liquefaction 45,2 percent and transport 16,4 percent,

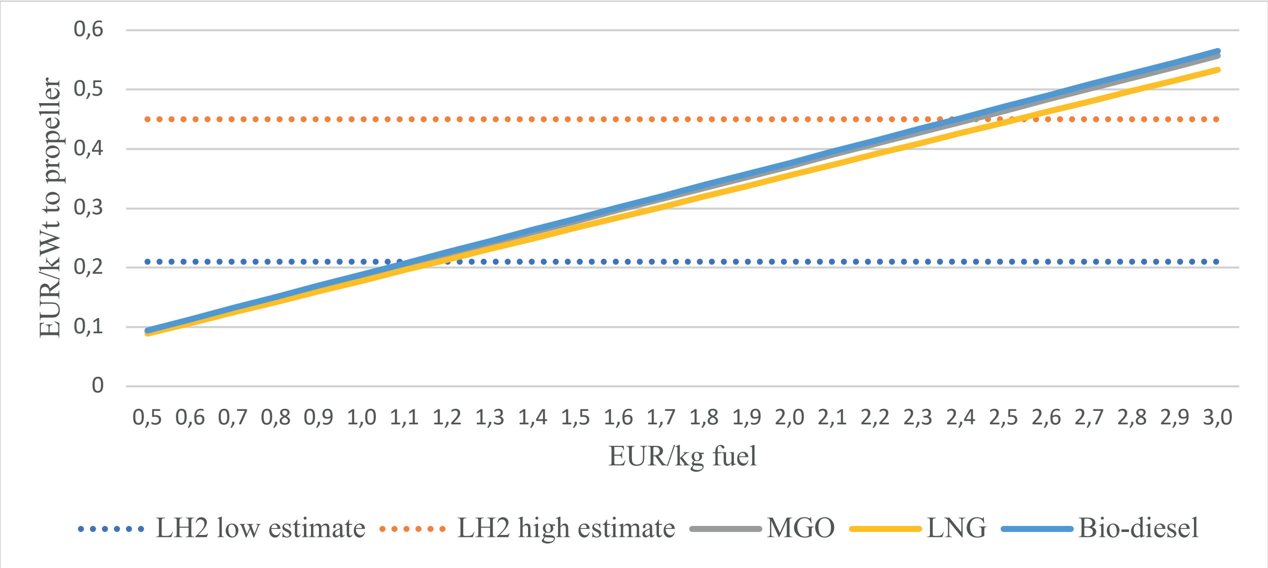
Table 14: Cost per kWt with 2030-price for LH_2

Fuel	*Retail price EUR/kg (ex. vat)*	*Cost in EUR per kWt*	**LH_2-price to match other fuels**
MGO	0,61	0,11	1,9
LNG	0,76	0,14	2,3
Ammonia (fuel cell)	0,51	0,18	3,0
LPG	1,10	0,19	3,2
Ammonia (combustion)	0,51	0,20	3,3
LH_2– Best case NG	3.5	0,21	N.A.
Methanol	0,8	0,25	4,1
Bio-diesel	1,68	0,32	5,3
LH_2– High estimate	7.5	0,45	N.A.

In figure 34 we illustrate a variation in prices per kWt for other fuels compared against a set price of 3,5 EUR/kg LH_2 (low estimate) and 7,5 EUR/kg LH_2 (high estimate).

If the predicted LH_2 in 2030 holds true we see what the comparable price level is for other fuels

Figure 34: Price development of fuels compared to 2030-prices of LH_2



7. Future demand for liquid hydrogen

The most important factor for the dimension of a future value chain for liquid hydrogen is the expected market demand. This has important implications for the production capacity, size of storage and distribution and bunkering units.

In a recent analysis of hydrogen in Norway, DNV-GL identified 186 vessels that spent most of their sailing time in Norwegian waters and have at least half of their calls in one of five ports DNV-GL sees as early adopters of hydrogen infrastructure[175]. Based on their assessment of the maturity of hydrogen solutions for different vessels, they estimate that a total of 18 vessels are converted to hydrogen by 2030, with an annual demand of 17 900 tons/year[176].

Table 15: Market demand for hydrogen in 2030[177]

Vessel	*Theoretical number of vessels*	*Number of H_2-vessels by 2030*	*Estimated demand tons/year*
Car ferry	9	9	10 000
Offshore service	8	4	2 500
Coastal route (Kystruten)	13	Not quantified	2 000
Cruise	48	Not quantified	1 200
Service/others	22	Not quantified	1 200
High-speed crafts	40	5	1 000
Fishing	48	Limited testing	Negligible
Bulk and cargo	7	Limited testing	Negligible
Total	**186**	**18**	**17 900**

In this early transition phase from fossil fuels, the yearly demand for the 18 vessels equals a daily demand of ca 49 tons of LH_2. As seen from table 15, the need for liquid hydrogen in the DNV-GL scenario by 2030 is more than double the current European production capacity of liquid hydrogen.

To supply such volumes of liquid hydrogen an increase in liquefaction capacity is Norway to minimize transportation costs and CO_2-emissions, given that a full CCS value chain is developed for production of blue hydrogen from gas reformation.

Continuing from the DNV-GL scenario, we have studied how a major transformation of fuel supply to the vessels represented in our study: car ferries, high-speed crafts and platform supply vessels would affect the need for LH_2 in Western Norway.

The vessels represented in our study: car ferries, high-speed crafts and platform supply vessels use MGO today, with a few vessels running on LNG. Our approach for car ferries and high-speed crafts has been to identify the routes that are most likely to run on hydrogen and use their current fuel consumption to estimate how much LH_2 they would use with a similar operational profile.

For PSVs we have used fuel data from DNV-GL[178] to estimate the number of PSVs operating in Norwegian waters and combined them with port calls to get a geographical overview of the activity. The calculations from MGO and LNG are made by using known quantities of energy

[175] Bergen, Ålesund, Tromsø, Kristiansund and Stavanger
[176] 9 car ferries, four PSVs and 5 high-speed crafts
[177] DNV-GL (2019)
[178] DNV-GL (2016) and (forthcoming)

per kilo for different fuel types and taken into account different efficiency for the powertrains[179].

Doing this presents us with a maximum amount of LH_2 needed for three vessel types in our geographical area of interest. However, it is highly uncertain how fast the deployment of hydrogen vessels will be, whether there are other emission-free alternatives that reduce the demand or how the hydrogen demand is divided between gaseous and liquid form.

For smaller quantities, for example short routes in remote locations, locally produced gaseous hydrogen from electrolysis might be the best option. This will not impact the need for hydrogen but reduces the need for liquefaction capacity. To address the uncertainty on the demand-side, we also show scenarios where 50 and 25 percent of the combined fuel consumption on a county level is LH_2.

7.1 Car ferries

The Norwegian Road Authorities has estimated a national need for 10 000 tons of hydrogen per year for car ferries, but mainly for just a few of the longer ferry routes. In the five counties covering the western coast of Norway we have identified two ferry routes:

- Hjelmeland-Nesvik in Rogaland
- Halhjem-Sandvikvåg in Hordaland

The route from Hjelmeland to Nesvik is part of a developmental contract recently won by Norled, for the development of the first car ferry using hydrogen as fuel.

Halhjem-Sandvikvåg is part of the E39 – the main road along the Western Coast of Norway and has a crossing time of about 40 minutes. The ferries are a gas-electric hybrid, bunkering LNG at Halhjem combined with battery charging.

Two other routes currently in operation – Mekjarvik-Kvitsøy and Arsvåg-Mortavika, both in Rogaland, would also be suitable for a conversion to hydrogen, but are no longer publicly tendered ferry routes from 2025, due to the planned building of the road/bridge project Rogfast.

In addition to the two routes identified above, other routes might end up being run by hybrid-vessels, especially where the quality of the local grid prevents a fully battery-electric solution. But it has been outside the scope of this report to consider grid capacity and/or detailed operational profiles for those ferry routes.

Table 16 – LH_2 for Car Ferries

Route	*Region*	*LH2 tons/year*	*LH2 tons/day*
Halhjem-Sandvikvåg	Hordaland	5 743	Ca 15,75
Hjelmeland-Nesvik	Rogaland	54,75	0,15
Total		**Ca 5 797**	**Ca 16**

7.2 High speed crafts

With longer distance, a need for high speed and a lack of storage volume/weight limitations makes liquid hydrogen the best solution for non-emission high speed crafts. A recent study from Sandia Laboratory of zero emission powertrains for a range of vessels found that the

[179] 45 % efficiency for combustion engines and 50 % efficiency for fuel cells

energy storage density of LH_2 (1,3 kWh/l) was higher compared to gaseous hydrogen tanks (0,36 kWh/l) and battery systems (ca. 0,09 kWh/l)[180].

In the table below estimates for annual fuel consumption provided by Selfa Artic are used to estimate the necessary volume of LH_2. We have only included routes with a crossing longer than 10 nautical miles – as shorter distances could be operated primarily by battery-electric powertrains.

For the daily fuel consumption, we have divided the annual consumption by 365 days. Ideally a more detailed study of daily departures on weekdays, weekends and holidays should be conducted to provide even more specific estimates, but that has been outside the scope of this report. Thus, it is reasonable to expect that the daily LH_2 consumption is a bit higher on busy weekdays than showed in table 16 and lower during weekends/public holidays.

Table 17 - LH_2 for High Speed Crafts

Route	*Region*	*LH2 tons/year*	*LH2 tons/day*[181]
Trondheim – Kristianssund	Trøndelag	1 371	3,8
Trondheim-Brekstad	Trøndelag	302	0,8
Namsos-Leka og Rørvik	Trøndelag	212	0,6
Ålesund-Nordøyane	Møre og Romsdal	413	1,1
Molde-Helland-Viksebusekken	Møre og Romsdal	311	0,9
Bergen-Sogn-Flåm	Sogn og Fjordane	1 447	4,0
Bergen-Nordfjord	Sogn og Fjordane	1 281	3,5
Sogn-Nordfjord	Sogn og Fjordane	576	1,6
Florø-Svanøy-Askrova	Sogn og Fjordane	250	0,7
Florø-Fanøy-Barekstad	Sogn og Fjordane	154	0,4
Florø-Måløy	Sogn og Fjordane	94	0,3
Ortnevik-Vik	Sogn og Fjordane	91	0,2
Flåm-Balestrand	Sogn og Fjordane	78	0,2
Hardbakke-Mjømna	Sogn og Fjordane	44	0,1
Eivindvik-Mastrevik	Sogn og Fjordane	43	0,1
Hardbakke-Utvær	Sogn og Fjordane	31	0,1
Sunnhordland-Austevoll-Bergen	Hordaland	1 504	4,1
Rosendal-Bergen	Hordaland	311	0,9
Norheimsund-Eidfjord	Hordaland	114	0,3
Austevollruten	Hordaland	88	0,2
Reksteren-Våge-Os	Hordaland	62	0,2
Stavanger-Ryfylke	Rogaland	803	2,2
Stavanger-Hjelmeland	Rogaland	730	2,0
Stavanger-Lysebotn (kombi)	Rogaland	326	0,9
Stavanger-Kvitsøy	Rogaland	110	0,3
Stavanger-Fisterøyene (kombi)	Rogaland	35	0,1
Total Trøndelag		1 185	5,2
Total Møre og Romsdal		723	2,0
Total Sogn og Fjordane		4 087	11,2
Total Hordaland		2 079	5,7
Total Rogaland		2 003	5,5
Total		**10 778**	**29,5**

180 Minnehan & Pratt (2017)
181 Yearly consumption divided by 365

In total the high-speed crafts from the southern part of Trøndelag to Rogaland have an annual need of nearly 11 000 tons of LH_2 – representing a daily demand of 29,5 tons of LH_2. The longest crossings have a daily demand of plus/minus 4 tons of LH_2. That is a daily demand equivalent to the amount transported by a truck with a cryogenic tank. Other routes have a daily demand that would indicate that one delivery/bunkering from a distribution truck per week is enough.

From a regional perspective the county of Sogn and Fjordane has the largest demand with 38 percent of the consumption. However, this figure also includes two routes going between Hordaland and Sogn og Fjordane, for which they have the administrative responsibility.

7.3 Platform Supply Vessels

While car ferries and high-speed crafts represent a stable market – organized through public tenders, the PSV market is much more volatile and difficult to estimate.

In an analysis for the Green Coastal Shipping Programme, DNV GL has, based on data from 2013, estimated the yearly fuel consumption from domestic traffic[182] for PSVs to be approximately 290 000 tons of MGO. Looking at CO_2-emissions from PSVs from 2013 and 2017 it is fair to assume that the fuel consumption has remained relatively stable[183].

Using data on port calls from Statistics Norway it is possible to estimate regional numbers on fuel for PSVs[184], with the main assumption being that the vessels refuel in or nearby the port they call to.

Table 18 – Regional fuel consumption for PSVs

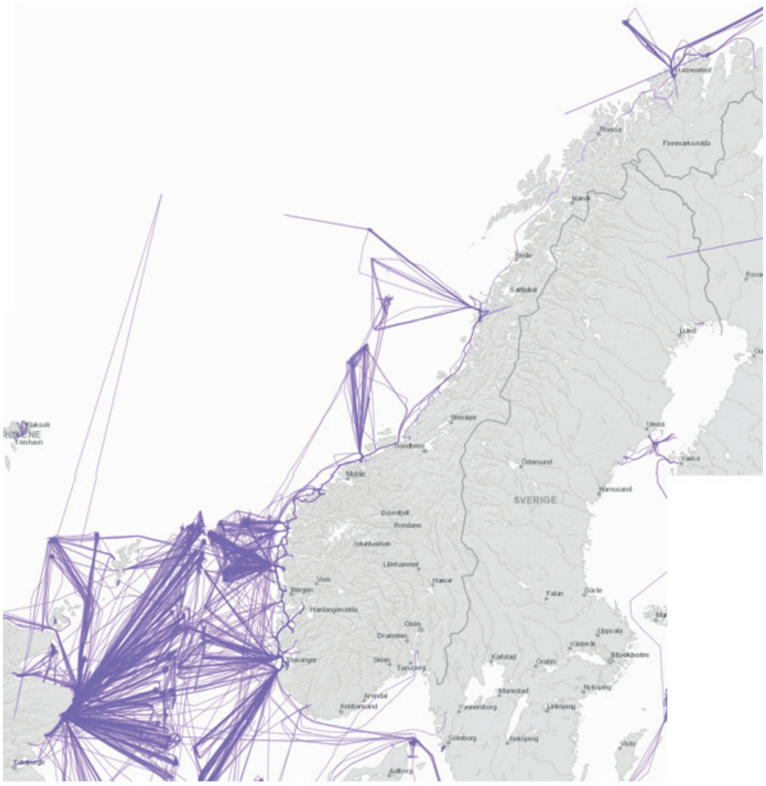
Geographical area	*Number of port calls*	*Percentage of total calls*	*MGO in tons*
Rogaland	2907	25,4 %	73 660
Hordaland	3853	33,7 %	97 730
Sogn og Fjordane	1496	21,8 %	63 220
Møre og Romsdal	1569	13,7 %	39 730
Trøndelag	30	0,3 %	760
Rest of Norway	585	5,1 %	14 790
Total	**11 440**	**100 %**	**290 000**

As we see in table 18 and figure 35 – almost all the PSVs are in route between supply bases in Western Norway/Trøndelag and the Norwegian continental shelf. Of the 585 port calls in rest of Norway, 459 are in the municipality of Hammerfest in Finnmark, where Polarbase supplies the oil & gas activity in the Barents Sea.

The patterns of regional activity are also evident when looking at AIS-data provided by the Norwegian Coastal Administration.

[182] Defined as transport between Norwegian harbor and oil & gas installations in Norwegian waters
[183] DNV-GL (2017) and (2019)
[184] We are using port calls from 2013 in order to keep all data within the same year

Figure 35 – PSV activity in Norwegian[185]



By using the parameters from table 4 on fuel properties, we estimate that the current fuel consumption is equivalent with an annual LH_2 demand of nearly 90 000 tons.

Table 19 – LH_2 for Platform Supply Vessels

Region	*LH2 tons/year*	*LH2 tons/day*
Rogaland	23 830	65,3
Hordaland	31 617	86,6
Sogn og Fjordane	20 453	56
Møre og Romsdal	12 853	35,2
Trøndelag	245	0,67
Total	**88 999**	**243,8**

In 2014. Prototech presented a study of a hydrogen-run PSV, where they estimated an average consumption of 1,7 tons LH_2, with 3 tons of LH_2 per day as a worst-case scenario in heavy weather conditions[186]. For a week-long trip they suggest onboard storage of 12 tons of LH_2

An ongoing study by NCE Maritime Cleantech, Wärtsila and Equinor has estimated a daily average of 2 tons LH_2[187]. Based on this the volume identified in table 18 equals around 120 platform supply vessels in total.

[185] Data from Havbase/Norwegian Coastal Administration
[186] CMR Prototech (2014)
[187] NCE Maritime Cleantech, forthcoming

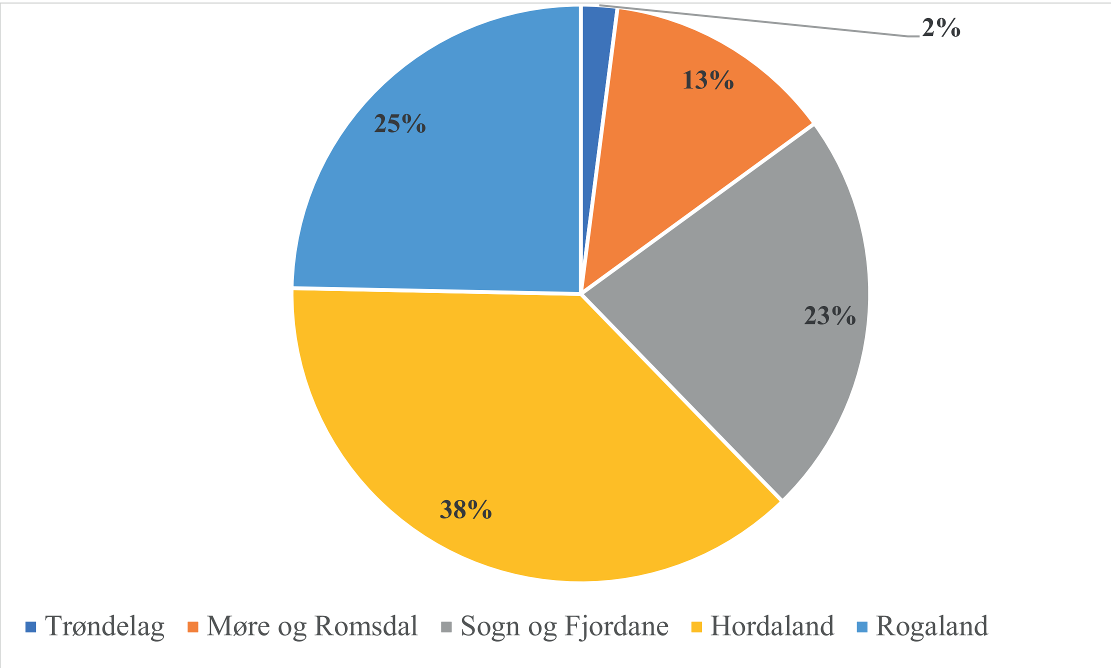
7.4 Summary – Demand of LH2

When we summarize the volumes identified in chapters 7.1 to 7.3, the total demand if all vessels convert to LH_2 is about 105 000 tons LH_2/year and 287 tons LH_2/day. In terms of the global production of liquid hydrogen today, such a demand would need over 80 percent of the production capacity. This is of course not a transformation that happens overnight and the numbers in table 20 must be looked upon as a maximum scenario without a clear timeline rather than a demand in 2030.

Table 20 – Demand of LH_2 per vessel category

	Trøndelag	*Møre og Romsdal*	*Sogn og Fjordane*	*Hordaland*	*Rogaland*	*Total*
High speed craft tons per year	1 885	723	3 417	2 079	2 003	10 108
High speed craft tons per day	5,2	2	9	6	5	28
Car ferry tons per year	0	0	0	5 743	55	5 798
Car ferry tons per day	0	0	0	16	0,2	16
PSV tons per year	246	12 853	20 453	31 617	23 830	88 999
PSV tons per day	0,67	35	56	87	65	244
Total tons per year	2 131	13 577	23 870	39 439	25 888	104 906
Total tons per day	6	37	65	108	71	287

Figure 36 – Future regional demand for LH_2



The two most southern counties, Rogaland and Hordaland, represent most of the LH_2-demand with over 60 percent of the total. As we move north the activity in the PSV-market decrease with Trøndelag being the county with the lowest share of the LH_2-demand.

As shown in table 19, just a few passenger routes or PSVs switching fuels would have a substantial demand for LH_2. With some of the longer high-speed routes needing around 4 tons of hydrogen per day, and a single PSV using about 2 tons per day, with a minimum storage of 6 tons of LH_2 for a three-day operation. In terms of the current production capacity in Europe, even the demand in Trøndelag from high-speed crafts equals the total capacity of either Lindes or Air Products liquefaction plants in Leuna and Rotterdam.

Without considering each individual car ferry, high-speed route or PSV we have also estimated the volume of LH_2 needed for a 50 and 25 percent conversion from MGO and LNG. The 25 percent-scenario is close to DNV-GLs estimate for 2030 and should be a realistic demand for the next 10-15 years in Western Norway, especially if upcoming tenders for the major high-speed crafts in Sogn og Fjordane and Trøndelag includes hydrogen as a potential energy carrier.

Table 21 – Demand of LH_2 – different scenarios[188]

Scenario	*100 % conversion to LH2*		*50 % conversion to LH2*		*25 % conversion to LH2*	
County	t/year	t/day	t/year	t/day	t/year	t/day
Trøndelag	2 131	6	1 066	3	533	1,5
Møre og Romsdal	13 577	37	6 789	19	3 394	9
Sogn og Fjordane	23 870	65	11 935	33	5 968	16
Hordaland	39 439	108	19 720	54	9 860	27
Rogaland	25 888	71	12 944	36	6 472	18
Total	104 905	287	52 454	144	26 227	72

Another way to calculate future market demand is to argue that the transformation of publicly tendered vessels will happen faster than in the private sector. Here, the authorities can include criteria for emission reduction that operators must follow. Also, hydrogen-powered car ferries and high-speed crafts are expected in 2021-22. From car ferries and high-speed crafts alone, the total demand of LH_2 is 44 tons per day, with a gravity of demand in the three southern counties.

In figures 37-40 we have visualized the volumes geographically. We have chosen to have separate maps for public tendered car ferries and high-speed crafts suitable for LH_2 and one indicating consumption for platform supply vessels.

[188] Figures are rounded to nearest whole number

Figure 37: Distribution of LH_2-need for car ferries and high-speed crafts: Møre og Romsdal and Trøndelag

Figure 38: Distribution of LH_2-need for car ferries and high-speed crafts: Hordaland & Sogn og Fjordane

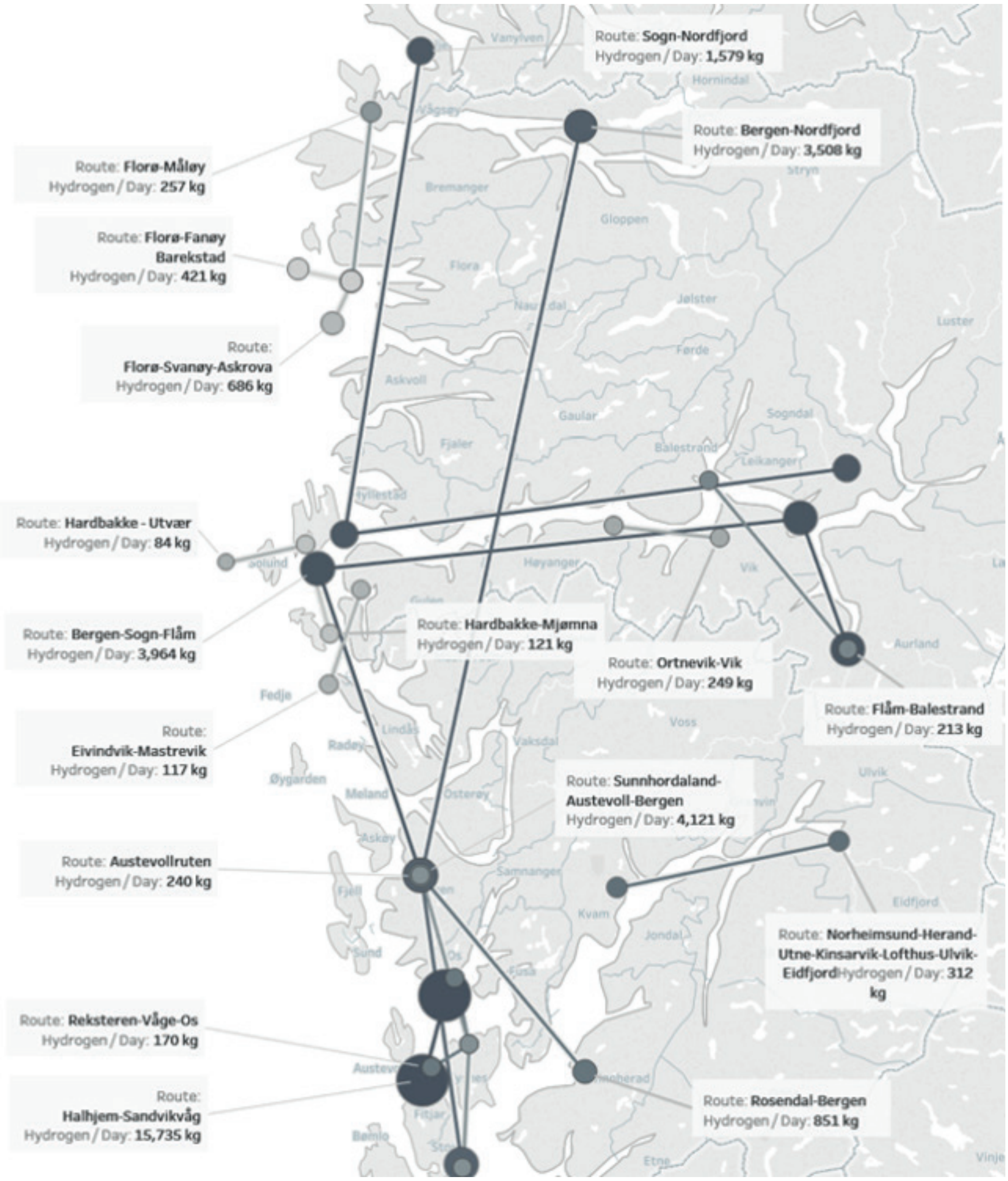


Figure 39: Distribution of LH_2-need for car ferries and high-speed crafts: Rogaland

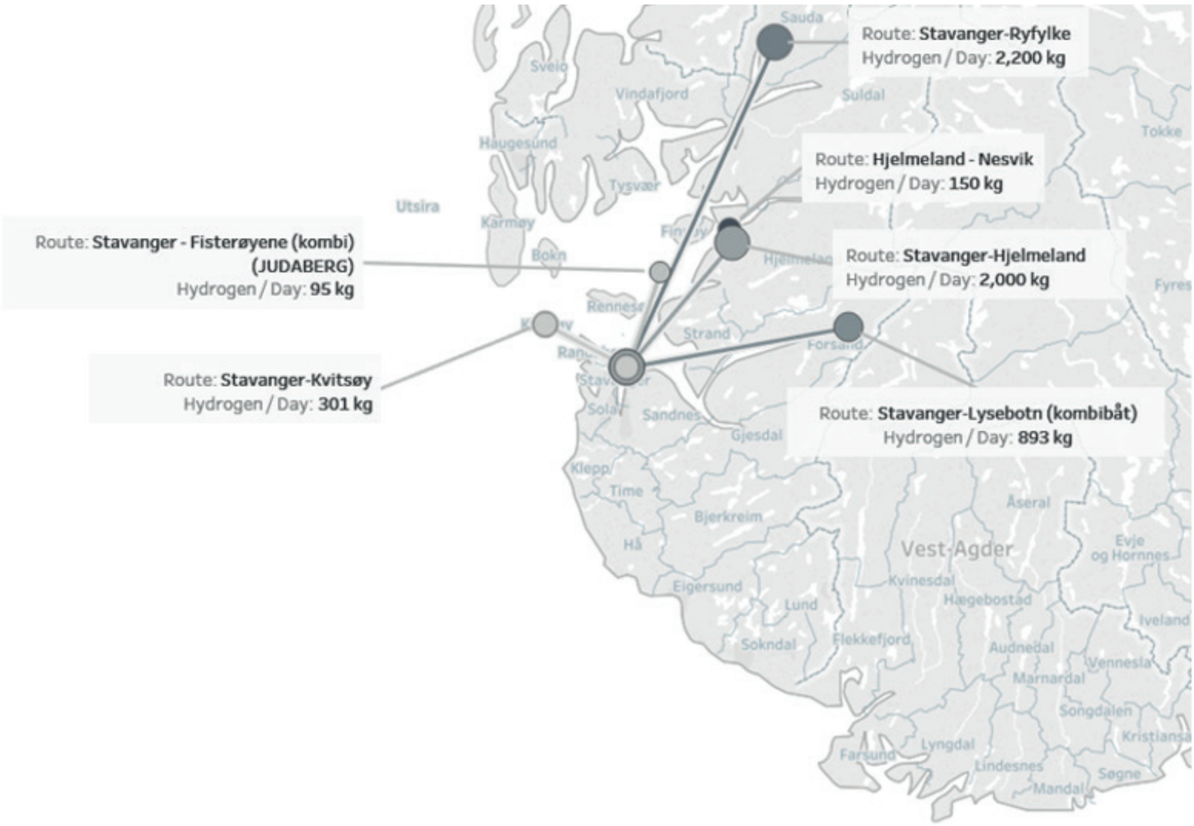
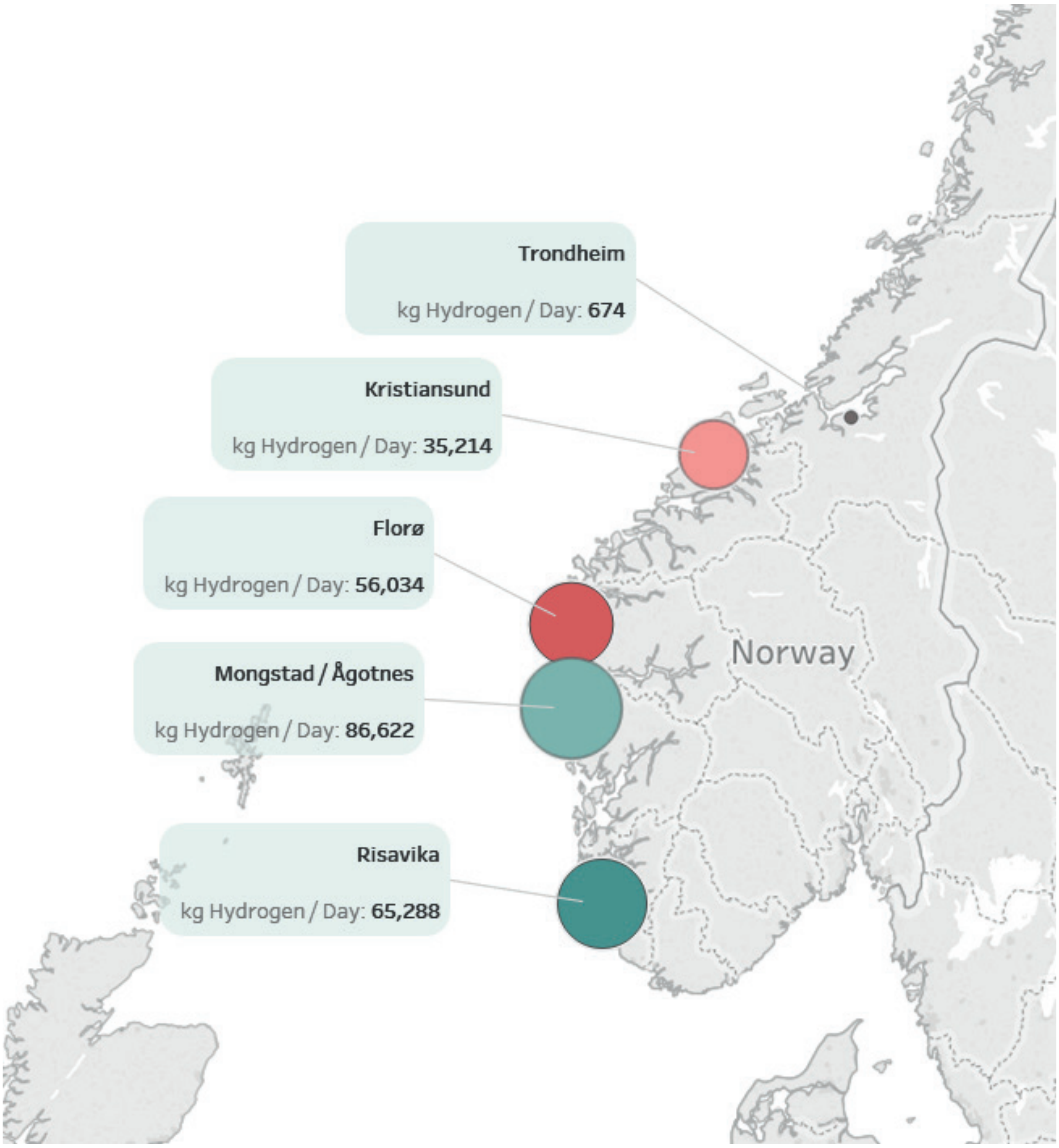


Figure 40: Geographic distribution of LH_2-need for platform supply vessels



7.5 Energy need – natural gas and electricity

Even with 25 percent of the current fuel consumption by car ferries, high-speed crafts and PSVs switching to LH_2, it represents a daily demand of just above 70 tons/day. This is about 3,5 times more than the current European liquefaction capacity. In order to achieve a larger restructuring of fuel in the maritime sector the volumes clearly show that in order to supply the Norwegian maritime sector with green hydrogen it is necessary to establish local production of hydrogen and liquification plants in Norway.

Following this line of thought, we have calculated the necessary energy input to produce the amounts above from either electrolysis or gas reformation. For each scenario we first identified how much energy the estimated volume of LH_2 contained. Secondly, using efficiency data for electrolysers and gas reformation plants with carbon capture and liquefaction plants, both state-of-the-art and with future technology developments, we estimated how much electricity and grid capacity, or natural gas is needed.

With a lower heating value of 33,3 kWh/kg LH_2 the volumes presented in table 20 above represent an annual energy amount ranging from 0,6 to 3,5 TWh. Considering the energy efficiency of electrolysis and gas reformation with carbon capture and the subsequent liquefaction, the needed energy input is nearly the double with today's technology.

Table 22: Energy needed for H2 production - Today and Future[189]

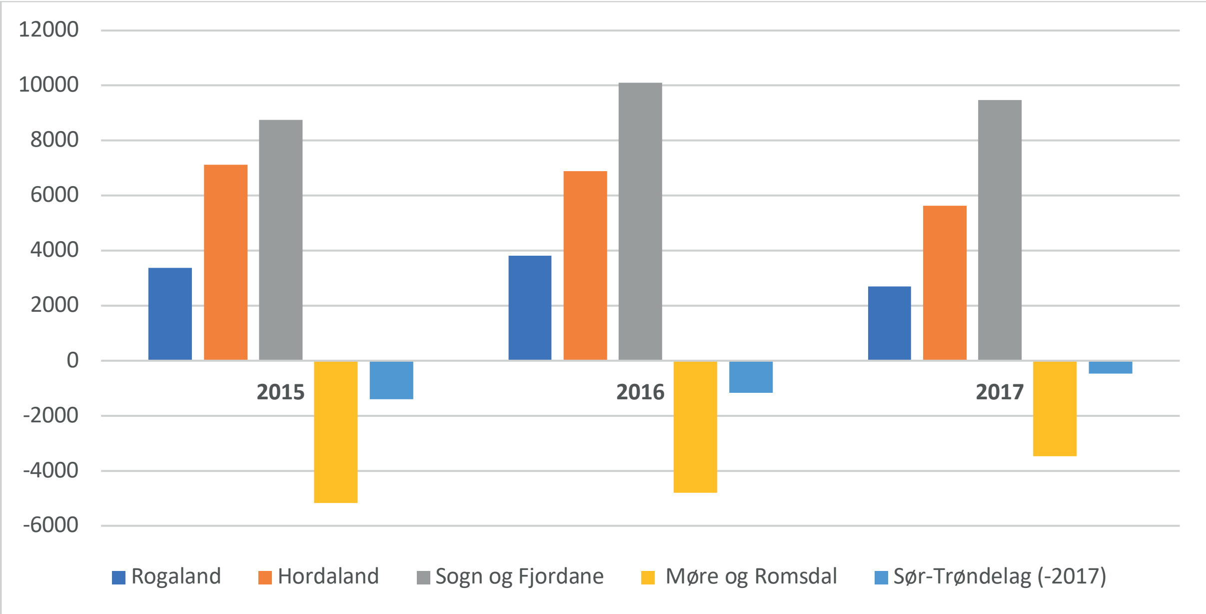
Scenario	*DNV-GL 2030*	*25 %*	*50 %*	*100 %*
Ton H2	17 900	26 277	52 454	104 906
Energy from H2 (TWh)	0,60	0,80	1,75	3,50
Electricity demand – today/future (TWh)	1,1/1	1,7/1,4	3,3/2,9	6,6/5,8
Total cap. load from grid – today/future (MW)	129/122	189/165	377/329	754/659
Demand of natural gas (Million SM³)	104,2/93,8	153,1/137,7	305,6/275	611,1/550

If produced by electrolysis the volumes described in this report would require a substantial amount of the Norwegian electricity surplus. In 2018 Norway produced 146 TWh of electricity, mainly from hydropower, and had a gross consumption of 136 TWh, resulting in a surplus of ca 10 TWh[190]. The volumes estimated by DNV-GL in 2030 would require 11 percent of this surplus, while a complete change to LH_2 for the vessels included in our scenario would require 66 percent of the surplus energy of 2018.

A county breakdown of gross consumption is not publicly available from Statistics Norway, but using net consumption shows that the counties of Rogaland, Hordaland and Sogn og Fjordane has a substantial surplus of electricity[191]. While Møre og Romsdal and Trøndelag does not have the same surplus of electricity, the natural gas facility at Tjeldbergodden process volumes that are more than large enough to provide hydrogen from gas reformation to the region (and beyond).

[189] Calculations are made from electrolyser data from IRENA (2018), liquefaction data from the Idealhy-project and calculations on SMR and carbon capture from IEAGHG (2017)
[190] Statistics Norway (2019a)
[191] Statistics Norway (2019d) and (2019e)

Figure 41 – Electricity balance – Western Norway 2015-2017



As a comparison the export of gas from Norway in 2017 was 117,4 billion SM^3, meaning that between 0,09 and 0,5 percent of the annual export is needed to produce the volume of hydrogen estimated. See the appendix for a regional breakdown of energy need and grid capacity.

8. Case studies

Based on the information presented in the previous chapters we have done preliminary case studies of how a value chain for liquid hydrogen would look like for three specific geographies:

- The car ferries between Halhjem and Sandvikvåg
- The high-speed craft from Bergen to Nordfjord (Selje)
- A PSV in traffic between the supply base at Mongstad and Statfjord

8.1 Car ferry Halhjem-Sandvikvåg

The ferry service between Halhjem and Sandvikvåg across Bjørnefjorden in Hordaland County are among the most heavily trafficked route in Norway, ranking third in number of daily vehicles, passengers and PCU-kilometers[192].

The service is currently run by Torghatten Nord on an eight year-long contract running from 2019, with five one-year options following 2027. Currently, Torghatten is phasing in new gas (LNG)-electric ferries to replace the previous LNG-ferries. From 2020, five gas-electric ferries operate the service, four in operation and one in reserve.

Table 23: Data Halhjem-Sandvikvåg

Value	***Data***
Length	22 km/12 Nm
Duration	45 min
Estimated speed	16 knots/hour
Daily crossings (from 2020)	54
Powertrain	Hybrid gas-electric (LNG)
Estimated annual energy consumption	212 500 000 kWh
Estimated energy consumption per crossing	ca 11 000 kWh
Estimated daily need of LH_2	16 tons

Today, LNG is stored locally at Halhjem in two 500 m^3 tanks, in total a gross volume of 1000 m^3, in proximity to the road. The tanks are filled from an LNG-trailer but can also be re-filled by an LNG-tanker.

[192] Norwegian Public Roads Administration (2016) – PCU = Passenger Car Units

Figure 42: LNG-storage at Halhjem

Based on our calculations the ferries need about 16 tons of hydrogen per day or about 4 tons of LH_2 per operational vessel.

A volume of 16 tons of LH_2 per day is enough to consider establishing a local hydrogen production with liquefaction capacity. But a lack of nearby energy resources, as well as its location between a potential production sites at Kollsnes (ca 85 km) and Matre where Gasnor, SKL and Kvinnherad Municipality (ca 100 km) have plans for a liquefaction plant, counts towards a solution with distributed LH_2 from a central production facility. In addition, there is no available land next to the quay, introducing the need for transport to the bunkering facility.

From an operational perspective, we assume it would be unsatisfying to have a logistical chain where the necessary fuel arrived on-site each day, without any local storage capacity in case of downtime at the hydrogen production facility or other forms of delivery problems. A delivery of 16 tons of LH_2 would take four trailers offloading per day. Considering an estimated 3,5-4 hours for delivery of four tons[193], it would potentially result in offloading of LH_2 16 hours per day. The duration can be reduced if the storage facility is designed to receive from multiple points simultaneously.

Ideally, the LH_2 would be delivered from a bunkering vessel capable of delivering several days of fuel in one offloading. This would remove the need for a minimum of four trailers per day and, with the transfer flow rate given by Moss Maritime in their design for a bunkering vessel, the offloading would go a lot quicker. With an unloading rate of 300 m^3/h it would take below two hours to fill a storage tank like the spherical solution used by Jaxa – with a capacity of 540 m^3 or 38 tons of LH_2. A storage solution with 700 m^3 would have enough fuel to cover three days of operation before a new shipment must arrive with a bunkering vessel.

[193] Klebanoff et.al (2018)

Figure 43: Spherical storage tank – Jaxa

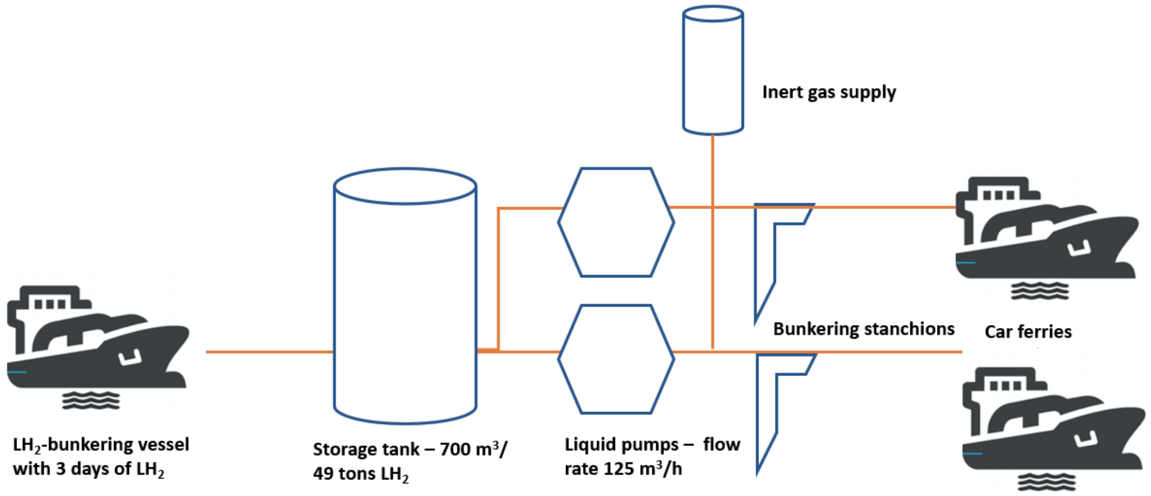
The tank is 12 meters high and would have enough hydrogen for two days, plus a sizeable margin.

Alternatively, if based on trailer transport, a 300 m^3 cylinder from an industrial gas supplier could provide a one-day-back-up, in case the daily delivery fails. Despite possible venting losses from a double transfer operation (trailer to storage to vessel), a local storage provides a much more flexible solution.

Based on the current schedule it would be advisable to have multiple lines from the storage to multiple bunkering stanchions. Between 06:00-22:00 all four ferries are in operation, before two ferries continue to operate until 00:45, and then three single departures from each direction between 00:45 and 05:30.

In the SF-BREEZE-project a transfer flow of 1000 kg LH_2/20-40 min is said to be manageable. The transfer time for 4 tons of LH_2 for one vessel would therefore be between 1h 20 min and 2h 40 min, plus pre-cooling and warming of lines and equipment before and after. The small bunkering window suggests that an LH_2-pump with a capacity of 200-250 m^3/h is needed to reduce the bunkering time or 125 m^3/h with two pumps connected to separate bunkering stanchions.

Figure 44: Simplified schematic flow of value chain - Halhjem



8.2 High-speed craft Bergen-Nordfjord

The route between Bergen and Selje in Nordfjord is 140 nautical miles long and has two return trips with 14 potential stops between the two end stops on weekdays and once during the weekend.

The current fuel consumption is reported to be around 500 kg diesel per hour for the five-hour voyage, about 2 500 kg diesel[194]. In addition, comes empty running while at quay and maneuvering in and out of the numerous stops underway. Looking at the annual fuel consumption of diesel an average of about 4 tons of hydrogen for a day of normal service with four crossings is estimated.

Table 24: Input high-speed craft Bergen-Nordfjord

Distance	*140 Nm*
Return trips per weekday	2
Number of stops, included end stops	16
Current fuel consumption one way	2500 kg diesel one-way + empty running and maneuvering
Current daily fuel consumption	10 000 kg ++
Daily LH_2-consumption with similar vessel	Ca 4 tons

Unlike the car ferry, the high-speed craft is much more weight sensitive and the vessel is unlikely to carry a full-day of fuel. A smaller high-speed craft (100 pax, 28 knots) designed by the Norwegian company Brødrene Aa as part of the Green Coastal Programme has a storage of 450 kg compressed hydrogen at 250 bar [195]. In the design for the high-speed craft SF Breeze (150 pax and 35 knots) the on- board storage was 1 200 kg LH_2, enough for two 50 nm-trips + a margin of 2-400 kg[196].

With a similar capacity for a LH_2-vessel going from Bergen to Selje it needs to refuel per every crossing. From a logistical point of view the bunkering would need to take place at the end stops as bunkering along the way would prolong the crossing.

[194] Correspondance with Norled, April 2017
[195] Nygård & Strømgren (2017)
[196] Pratt & Klebanoff (2016)

Thus, the vessel needs to bunker about 1 ton of LH_2 twice in Bergen and twice at Selje during a weekday. As Bergen and Selje are two widely different locations, both in terms of other traffic, geography and population, we look at the two end stops separately.

At Selje the high-speed craft hails in the centre of the village, close to the town hall, shops and pubs. The industrial harbour in the municipality is on the other side of the peninsula and not an option as a bunkering site.

Figure 45: Selje Harbour

The daily demand at Selje suggests that a solution with distributed hydrogen from a central production facility is preferable from an economic point of view.

With the current schedule bunkering would take place between in the afternoon (between 13-15) and after the final arrival at 21.40 in the evening (to prepare for the first departure the next day). From a logistical point of view, a delivery of 4 tons by trailer to a local storage unit every other day seems like a good solution. Pratt & Klebanoff (2016) estimate the cost for a storage unit of 4,2 tons and a bunkering stanchion that connects the storage unit and the vessel to 1,395 million USD.

With a window of two hours between arrival and departure in the afternoon a bunkering transfer flow as indicated in the SF BREEZE-project of 1000 kg LH_2 per 20-40 minutes, through pressure filling, is fast enough.

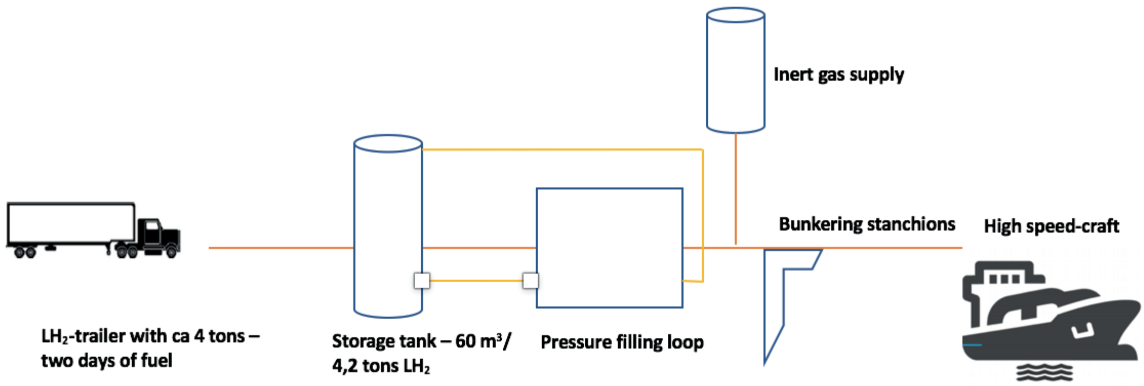
A project that might influence the bunkering solution at Selje is the Stad Tunnel, where the western entry point is located 6-7 nautical miles from the current quay. The project is fully financed in the national transportation plan for 2018-2029 and can be ready in 2026 at the earliest[197].

In the SF-BREEZE project they recommend a maximum distance of 5 nm between the bunkering facility and the embarkation point, however they have a smaller window between

[197] Stad Tunnel (2019)

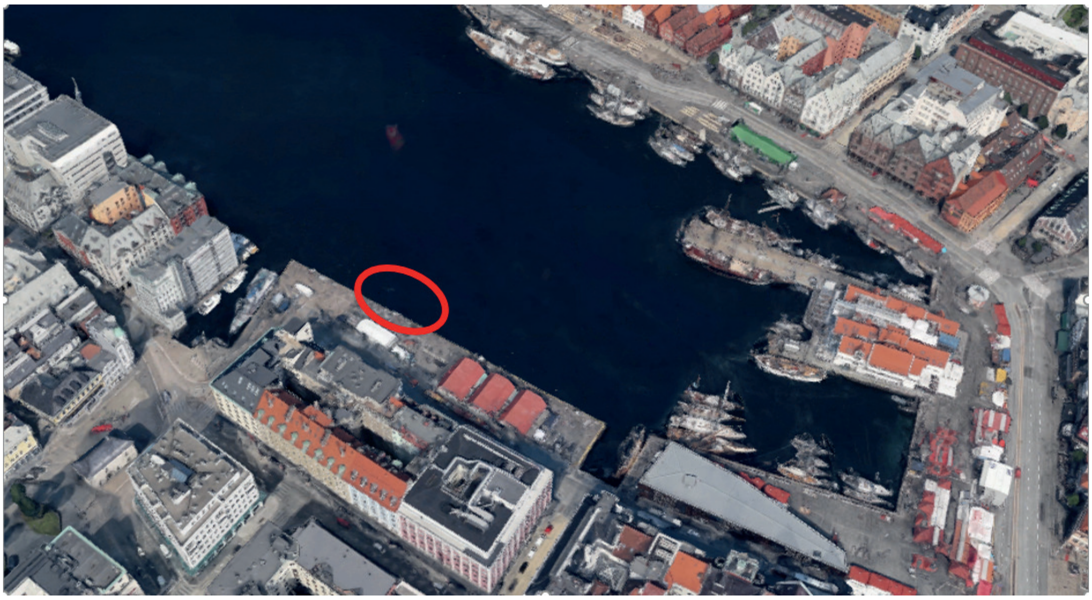
departures. If a larger bunkering facility is established in relations to the tunnel it can potentially also serve the high-speed craft.

Figure 46: Simplified schematic flow of value chain – Selje Harbour



In Bergen, the vessels call in the inner city. A previous study by Greensight has questioned whether it is possible to have any form of hydrogen bunkering due to public areas close by and limited space for trailers to operate[198]. Also, Bergen is a hub for several other high-speed crossings and probably be one of the harbours most suited for hydrogen on a larger scale, hence the findings made by DNV-GL (2019). They estimate a daily need of nearly 8 tons LH_2 in 2030, divided by high-speed crafts, a few PSVs and testing of fuel cells & hydrogen at Kystruten[199]. Infrastructure to serve the high-speed craft from Bergen to Selje would likely also have the capacity to serve other end users.

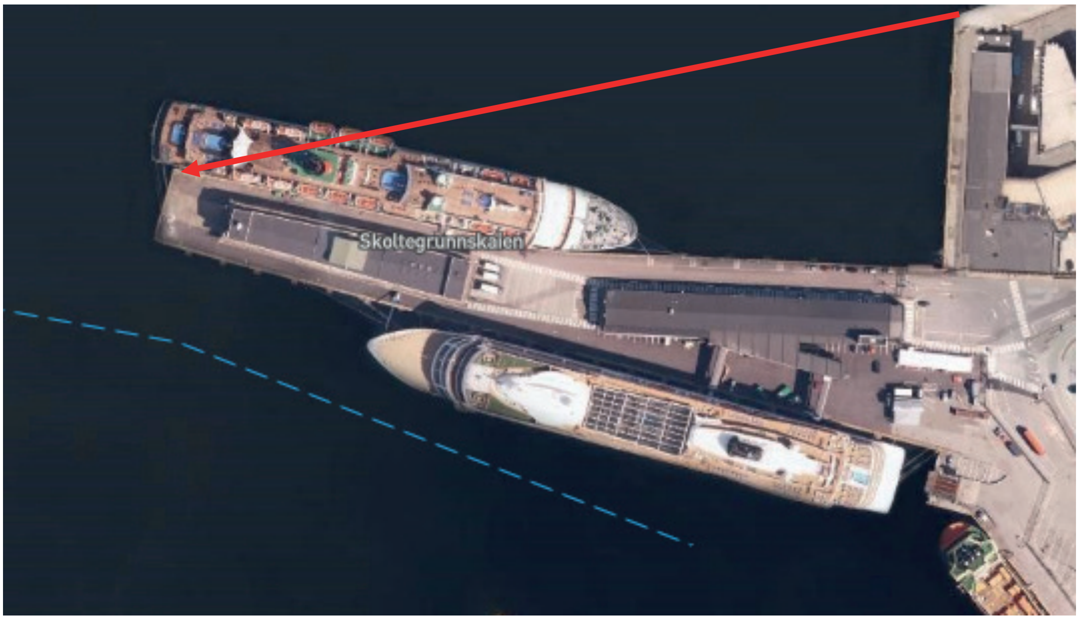
Figure 47: Bergen, Standkaien



[198] Greensight (2018)
[199] DNV-GL (2019)

A potential production site is Equinors gas terminal at Kollsnes, about 50 kilometers from the centre of Bergen. An amount of 8 tons per day could be transported by two trailers of 4 tons each to a local storage facility, or if the high-speed craft is the only end user in the beginning, a trailer every other day would be enough to provide the vessel with hydrogen. The most challenging task is perhaps to find room for a storage tank and bunkering stanchion. The Port of Bergen has suggested to the regional authorities to fill out a portion of the inner fjord to obtain new land, which could serve as a potential area. The potential new land area of roughly 17 000 m^2 is illustrated by the red line in the figure below.

Figure 48: Suggested new land in Bergen Harbour



A cryogenic tank of 100 m^3 – with a diameter of 3 m and length of 14 m can store just above 7 tons of LH_2 and can be a first step – with a continuous expansion of local storage as the demand increases.

8.3 PSV from Mongstad to Statfjord

Of the vessel-types we have included in the report, the platform supply vessels represent the largest single user, as the demand for ferry/high-speed crossings is divided between multiple vessels.

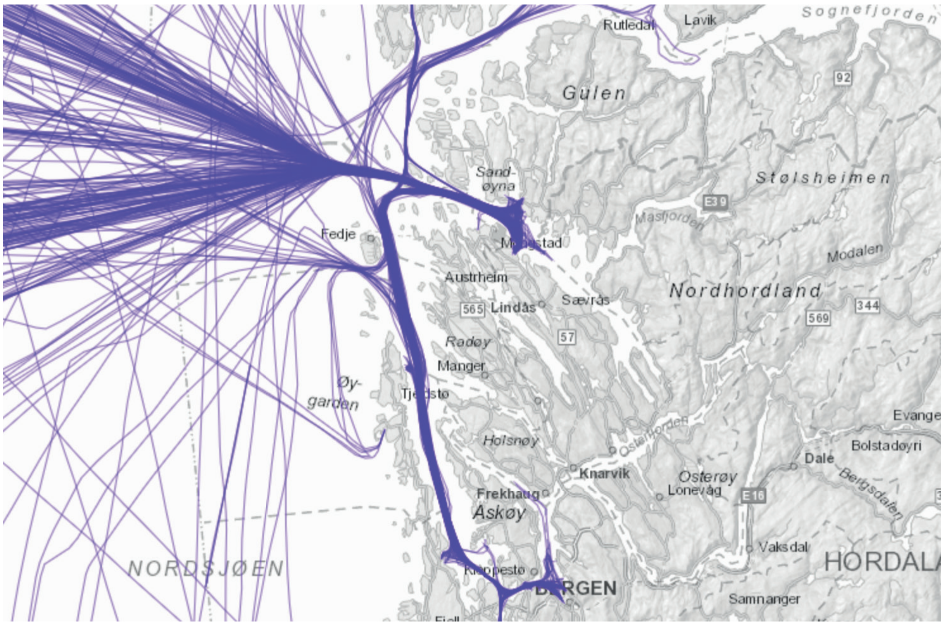
In table 20 we have listed input on a hydrogen-driven PSV from a research project done by CMR Prototech in 2014. The distances between Mongstad and the Statfjord-area is about 200 nautical miles. It is not given in the CMR-report which distance the PSV is designed to cover per day with the daily fuel consumption of 1701 kg LH_2 per day. As Statfjord are among the most western oil fields we have set a daily LH_2-use of 2 tons per day on average.

Table 25 – Input Platform Supply Vessel

Distance one-way Mongstad-Statfjord	Ca 200 nm
Estimated average LH_2 per day	2 tons
1 refuelling per week	Ca 12 tons
2 refuelling per week	Ca 6 tons
Expeditions per week	2
On-board storage with 1 refuelling	192 m^3
On-board storage with 2 refuellings	108 m^3

CCB Mongstad is the main supply base for Equinors activity in the North Sea Today they have a storage capacity of 9000 m3 marine gas oil from Cirkle-K and 1000 m3 of LNG from Gasnor. As figure 48 shows it is a major hub for the PSV activity to and from the Norwegian continental shelf.

Figure 49 – AIS-data for PSV-traffic to Mongstad[200]



In 2016 Greenstat did a feasibility study on potential hydrogen production from electrolysis at Mongstad, then with the intention to supply Equinors refinery. The study showed a maximum production per day of 31,2 tons of compressed hydrogen per day[201]. If those volumes are liquefied a production of green LH_2 at Mongstad could provide 2,5 platform supply vessels per day, based on a once-a-week refuelling of 12 tons, in total 16-18 vessels per week.
The scope of this report does not allow for a detailed study of how a production plant at Mongstad should be designed, but a possible solution is to transport low pressure compressed hydrogen in a pipeline from the electrolyzer for compression and liquefaction closer to the shoreline.

But to provide a single PSV with LH_2 it will be provided from an external production plant. A solution is distribution by bunkering vessel from a potential production from gas reformation at Kollsnes, about 20 nautical miles north of Mongstad. Offloading into a 540 m^3-storage tank, see figure 23, could provide fuel for three weeks for a single PSV. Depending on the

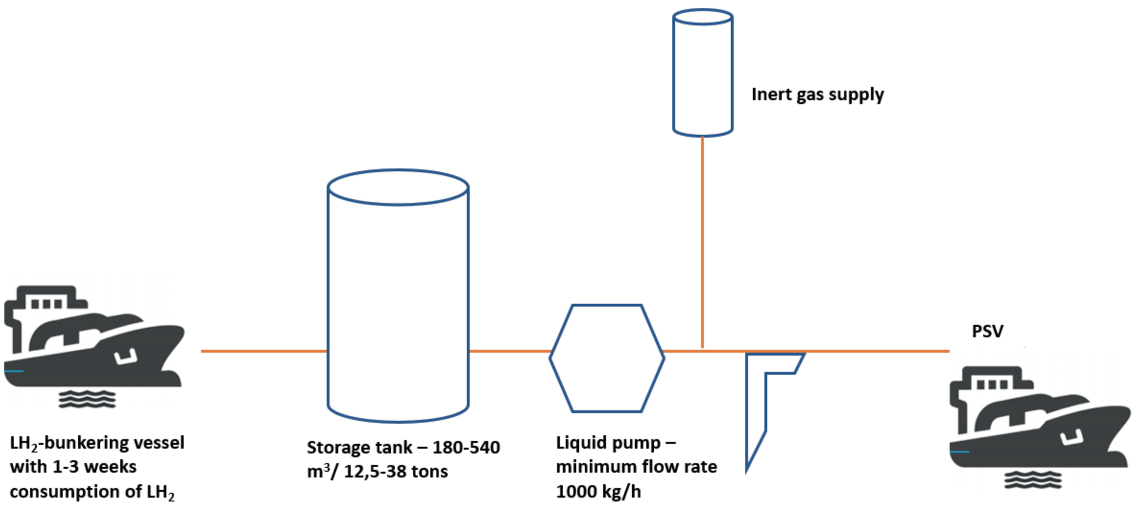
[200] Havbase (2019)
[201] Greenstat (2016)

need for flexibility and ability to schedule bunkering it is also possible to have a single weekly bunkering with LH_2 distributed by three trailers with 4 tons each. Distribution by truck would minimize the need for infrastructure on the shoreside, especially if it is possible to use pressure filling to transfer LH_2 on-board.

But without fixed departure times and a volatile work load, the flexibility provided by a local storage unit and a LH_2-pump for speedy transfer of fuel, seems like the best solution for a PSV. The size of the storage unit is flexible, in their study CMR Prototech suggest a storage of 12 500 kg/LH_2 to match the weekly consumption of the vessel. While it increases CAPEX for storage, if supplied by a bunkering vessel a larger quantity stored locally would reduce the transportation cost per kg LH_2,

An LH_2-pump providing a flow transfer rate of 1000 kg LH_2/h would give an estimated refuelling time of 12 hours for 12 tons or six hours if the vessel refuels six tons twice a week.

Figure 50: Simplified schematic flow of value chain – Mongstad



9. Summary: Barriers for a liquid hydrogen value chain

The goal of this report was to examine a future value chain for liquid hydrogen in Norway, with a special focus on car ferries, high-speed crafts and platform supply vessels. This has identified several barriers that need increased intention in the years to come.

Demand for liquid hydrogen: A first step for a Norwegian value chain is to create a demand that leads to production of liquid hydrogen in Norway. Our volume scenarios and cost comparisons clearly show that the current European capacity is both too small and distant to serve a Norwegian maritime market. And even with the LH_2-prices available in Europe, the cost per kWt to the propeller of a vessel represents a substantial increase in fuel cost.

To reduce cost per kg the research literature clearly states that size matters. In combination with technology improvements a tenfold increase in production capacity per day can reduce the energy needed for liquefaction by 50 percent[202]. A minimum production capacity of 10-15 tons LH_2 per day has been mentioned by Equinor and SKL/Gasnor for their potential production at Tjeldbergodden and Kvinnherad.

A large barrier is therefore to substantiate a demand of liquid hydrogen large enough for trigger investment in hydrogen production and liquefaction in Norway. As seen from the development of electric ferries and the first car ferry on LH_2, public tenders can be an effective tool. Our data on future demand high-speed crafts show that several crossings would require around 4 tons per day and the car ferry crossing from Halhjem to Sandvikvåg requiring around 15 tons per day on its own.

Cost development: In addition to the scale of production, a positive cost development is closely connected to three areas: the cost of energy needed to produce hydrogen, increased efficiency for all parts of the value chain and a continued fall in capital cost for infrastructure. With about half of the production cost per kg of hydrogen being energy cost[203], as well as a substantial energy need for liquefaction, a decrease of cost depends on stable energy prices or the ability to utilize "trapped power" outside of energy markets.

Also, for production of hydrogen from natural gas, which currently is cheaper than electrolysis, the establishment of and cost associated with CCS provides an element of uncertainty. Our run-through of criteria for blue and/or green hydrogen shows that CCS is necessary in order to achieve a low enough level of $kgCO_2/kg\ LH_2$ to label hydrogen from natural gas as blue hydrogen.

Technology: While there is a continued need for increased efficiency, both production and liquefaction of hydrogen is considered as a mature industry, from few, but highly competent industrial gas companies. The last year has also seen a spike in new capacity being built in the US (3x30 tons per day) and a doubling of Lindes plant in Leuna from 5 to 10 tons per day. In terms of land-based storage of LH_2 there are several suppliers with experience and availability for cryogenic storage tanks and there exists large solutions developed for space industry.

[202] Idealhy (2013)
[203] DNV-GL (2019)

As we move further along the value chain the need for technology development increases. Currently distribution of LH_2 in Europe is done by trailer truck or by ISO-containers on ships. This is a suitable solution for small volumes, but as seen in our case studies it is not a very cost efficient or flexible form of distribution for larger volumes. The development of LH_2-tankers that can supply bunkering sites along the coastline is necessary for an effective distribution of large volumes.

In general, for distribution and bunkering, suppliers seem to believe that existing technology for LNG can be modified and adapted to LH_2. This includes tanks, submerged pumps for offloading, vacuum insulated pipes and valves and flexible pipes or loading arms. However, this requires considerable engineering and qualification before solutions are commercially available for maritime applications[204].

Regulations and standards: While some regulations and standards are developed for hydrogen as an energy carrier, less is available for maritime use of liquid hydrogen. In Norway it falls to a large degree under the general regulation on handling of dangerous substances with references made to maritime use of LNG. A development of international standards for a maritime use of hydrogen, especially concerning bunkering, is needed. Also hydrogen should be more directly addressed in national guidelines following the regulation on handling of dangerous goods.

Spatial planning: The lower energy density, 8500 MJ/m^3 compared to 38 000 MJ/m^3 for MGO and 22 000 MJ/m^3 for LNG, makes liquid hydrogen a more area demanding solution. As an example, we showed how much storage was needed to match the current amount of energy stored at major bunkering sites along the coastline (figure 29). In order to make room for infrastructure it is important that harbors, logistics bases and bunkering sites have this in mind for future spatial planning.

[204] Moss Maritime (2018)

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11. Appendix

Table 26: Energy efficiency throughout value chain – Electrolysis (kWh/kg)

	Electrolysis		
	kWh	Energy efficiency	Loss
Input Electrolysis/	51	65 %	
Input Liquefaction	11,9	74 %	
Output: LH₂ (LHV)	**33,3**	**48 %**	
Distribution / storage	33,2		0,3 %
Delivery/bunkering	31,55		5 %
Energy to propeller	15,77	50 %	
Total energy loss			**75 %**

Table 27: Energy efficiency throughout value chain – Gas reformation (kWh/kg)

	Electrolysis		
	kWh	Energy efficiency	Loss
Input Gas reformation with Carbon capture/	48	70 %	
Input Liquefaction	11,9	74 %	
Output: LH₂ (LHV)	**33,3**	**53,7 %**	
Distribution / storage	33,2		0,3 %
Delivery/bunkering	31,55		5 %
Energy to propeller	15,77	50 %	
Total energy loss			**73,5 %**

Table 28: Energy needed for H2 production – Rogaland

Scenario	***25 % conv. to LH_2***	***50 % conv. to LH_2***	***100 % conv. to LH_2***
Ton H2	6 472	12 944	25 888
Energy from H2 (GWh)	220	430	860
Electricity demand – today/future (GWh)	410/360	820/710	1630/1420
Total cap. load from grid – today/future (MW)	47/41	93/81	186/163
Demand of natural gas (Million SM^3)	37,7/33,90	75,4/67,9	150,8/135,7

Table 29: Energy needed for H2 production – Hordaland

Scenario	***25 % conv. to LH_2***	***50 % conv. to LH_2***	***100 % conv. to LH_2***
Ton H2	9 860	19 720	39 439
Energy from H2 (GWh)	330	660	1310
Electricity demand – today/future (TWh)	620/540	1240/1080	2480/2170
Total cap. load from grid – today/future (MW)	71/62	142/124	284/248
Demand of natural gas (Million SM^3)	57,4/51,7	114,9/103,4	229,7/206,8

Table 30: Energy needed for H2 production – Sogn og Fjordane

Scenario	*25 % conv. to LH_2*	*50 % conv. to LH_2*	*100 % conv. to LH_2*
Ton H2	5 968	11 935	23 870
Energy from H2 (GWh)	200	400	790
Electricity demand – today/future (TWh)	380/330	750/660	1500/1310
Total cap. load from grid – today/future (MW)	43/37	86/75	172/150
Demand of natural gas (Million SM^3)	34,8/31,3	69,5/62,6	139,0/125,1

Table 31: Energy needed for H2 production – Møre og Romsdal

Scenario	*25 % conv. to LH_2*	*50 % conv. to LH_2*	*100 % conv. to LH_2*
Ton H2	3 394	6 789	13 577
Energy from H2 (GWh)	110	230	450
Electricity demand – today/future (GWh)	210/190	430/370	860/750
Total cap. load from grid – today/future (MW)	24/21	49/43	98/85
Demand of natural gas (Million SM^3)	19,8/17,8	39,5/35,6	79,1/71,2

Table 32: Energy needed for H2 production – Trøndelag

Scenario	*25 % conv. to LH_2*	*50 % conv. to LH_2*	*100 % conv. to LH_2*
Ton H2	533	1066	2131
Energy from H2 (GWh)	20	40	70
Electricity demand – today/future (GWh)	34/29	70/60	130/120
Total cap. load from grid – today/future (MW)	4/3	8/7	15/13
Demand of natural gas (Million SM^3)	3,1/2,8	6,2/5,6	12,4/11,2

Table 33: Ex.Transportation cost to Florø from Tjeldbergodden and Kvinnherad

Input		
Cost per km	6,93 NOK	
Cost per hour	549 NOK	
Cost per tonn in terminal services	11 NOK + 136 NOK per shipment	
Amount of LH_2	4000 kg	
Variable cost	**Tjeldbergodden**	**Kvinnherad**
Total cost per km	5 766 NOK	4 851 NOK
Total cost per hour)	10 980 NOK	8 784 NOK
Total terminal cost	180 NOK	180 NOK
Ferries/toll	7 430 NOK	3 994 NOK
Cost per kg LH_2	6,09 NOK	4,43 NOK

Table 34: Regulations, standards and codes for hydrogen[205]

Regulations (legally binding, international and national)	*UN ECE* • *Global Technical regulation (vehicles)* • *ADR (Road transport)* • *AND (Inland waterways transport)* *IMO* • *IMDG code (Maritime transport)* • *IGC code (Maritime transport in bulk)* • *IFG code (Ships)* *EU Directives* • *Pressure vessel (PED etc)* • *Explosive atmosphere (ATEX etc)* • *Fuelling stations (AFI etc)* *Norway (in Norwegian):* • *Forskrift om håndtering av farlig stoff* • *Forskrift om storulykkevirksomheter*
Standards & Codes (not legal documents, serve as guidelines to meet requirements)	ISO • TC 197 Hydrogen Technologies IEC • TC 105 Fuel Cell Technologies EIGA • IGC Docs Hydrogen stations, pipelines etc SAE International • J2601 Fueling protocols

[205] Hamanaka (2015)