# HOPE

## Hydrogen fuel cells solutions in shipping in relation to other low carbon options – a Nordic perspective

**WP2- Propulsion technology options for alternative marine fuels**

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# Report

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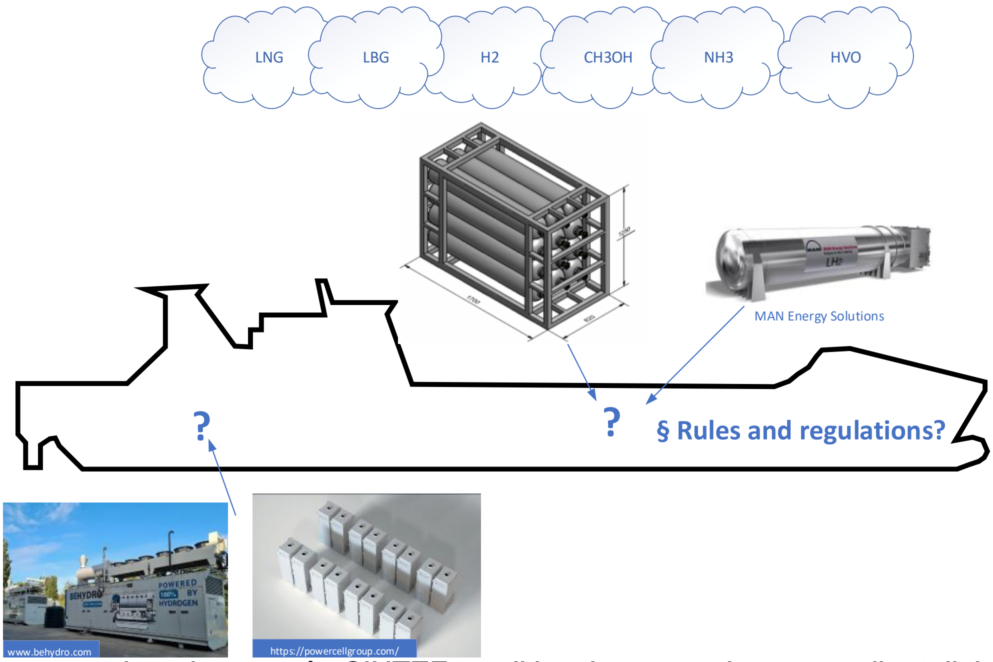




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**ABSTRACT**
Technology options for alternative low-carbon fuels in shipping is assessed with focus on hydrogen as fuel. Fuel choice has great impact on storage and bunkering systems on board a ship and on potential energy converters, i.e. internal combustion engines or fuel cells. In the report the energy density of the alternative fuels is briefly discussed, and consequences of storage volumes are evaluated. Further, energy converter options for burning hydrogen are evaluated. The evaluation is general but based on user requirements of a 20 MW propulsion plant on a Ropax case ship.

MANAGEMENT SYSTEM CERTIFICATION
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# Table of Contents

# 1 Abbreviations

| | |
|---|---|
| BOL | Beginning of Life (ref. Fuel cells) |
| CAPEX | Capital expenditure |
| CH3OH | Methanol |
| CBG | Compressed biogas |
| CNG | Compressed natural gas |
| CO | Carbon monoxide |
| CO2 | Carbon dioxide |
| CO2-eq | Carbon dioxide equivalent |
| DF | Dual Fuel |
| DWT | Deadweight tonnage |
| ECA | Emission Control Areas |
| e-fuel | Electrofuel |
| EU | European Union |
| EV | Electric vehicle |
| FAME | Fatty acid methyl ester(s) (=Biodiesel) |
| FC | Fuel cell |
| FCV | Fuel cell vehicle |
| FEED | Front-end engineering design |
| FT fuels | Fischer-Tropsch fuels |
| GHG | Greenhouse gas |
| H2 | Hydrogen |
| HCl | Hydrogen chloride |
| HF | Hydrogen fluoride |
| HHV | Higher heating value |
| HVO | Hydrogenated Vegetable Oil (=Renewable diesel) |
| ICE | Internal combustion engine |
| IMO | International Maritime Organization |
| IRR | Internal rate of return |
| LBG | Liquefied biomethane |
| LBSI | Lean burn spark ignited (engine) |
| ICE | Internal Combustion Engine |
| LH2 | Liquefied hydrogen |
| LCA | Life-cycle analysis |
| LHV | Lower heating value |
| LNG | Liquefied natural gas |
| LPG | Liquefied petroleum gas |
| NOx | Nitrogen oxides |
| OPEX | Operating expenditure |
| PEM | Polymer electrolyte membrane |
| PM | Particulate matter |
| PV | Photovoltaic |
| RED | Renewable Energy Directive |
| RORO | Roll on-Roll off (ship) |
| ROPAX | Roro and passenger (ship) |
| SNG | Synthetic natural gas |

| | |
|---|---|
| SOx | Sulphur oxides |
| TRL | Technology readiness level |
| TTW | Tank-to-wake |
| US | United States |
| WTT | Well-to-Tank |
| WTW | Well-to-Wake/propeller |

UNITS OF MEASURE

| | |
|---|---|
| EJ | Exajoule |
| GJ | Gigajoule |
| Gt | Gigatonne |
| kg | Kilogram |
| km | Kilometer |
| kt/y | Thousand tonnes per year |
| kW | Kilowatt |
| kWh | Kilowatt hour |
| L | Litre |
| L/d | Litres per day |
| MJ | Megajoule |
| Mt | Million tonnes |
| MtCO2 | Million tonnes of carbon dioxide |
| MW | Megawatt |
| MWh | Megawatt hour |
| m3 | Cubic metre |
| t | Tonne |
| TWh | Terawatt hour |
| t/d | Tonnes per day |
| t/y | Tonnes per year |
| nm | Nautical mile |

## 2 Executive Summary

The HOPE project addresses how regional shipping in the Nordic region can do the transition to become fossil-free. The project aims at clarifying the potential role of hydrogen based marine solutions in reducing the Nordic greenhouse gas emissions.

This report evaluates ship propulsion technology options for alternative fuels with focus on hydrogen as fuel. State of the art for alternative marine fuels are also outlined. To evaluate hydrogen as fuel a case ship has been defined to serve the Gothenburg – Frederikshavn route and operational requirements from Stena form basis for evaluation of fuel storage system and power trains on board.

One challenge with low carbon fuel for maritime application is significantly lower energy density than traditional marine diesel as illustrated in Figure 4.2.

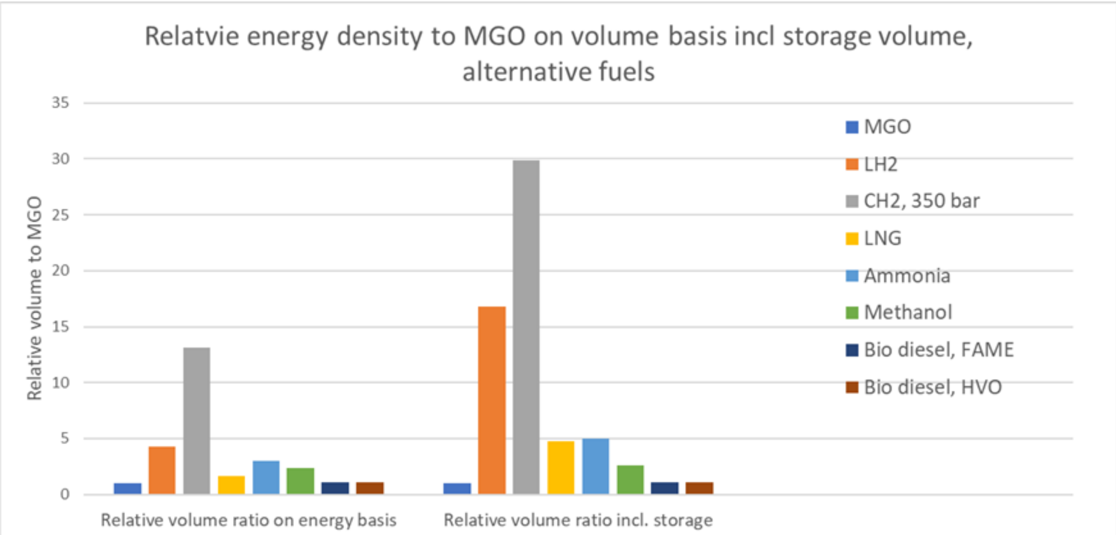



**Figure 1 – Relative energy density for alternative fuels compared to MGO on volume basis. Left bars: On energy basis. Right bars: On energy basis including storage volume.**

Liquified or compressed hydrogen is one of the most challenging fuel and can influence on the deadweight and load capacity of the ship in concern. Assuming that the endurance of a H2-fuelled ship is kept unchanged, significant weight and volume increase of the fuel storage and bunkering system is required. For such case additional weight for LH2 and $CH2_{350bar}$ storage is increased by about 3,5 and 6 times respectively and relative volume by 16-30 times compared to MGO as reference. To meet the low energy density of H2, alternative operation pattern is required with much more frequent bunkering than for traditional operation. By accepting lower endurance of the ship and design the fuel system to meet minimum endurance criteria, H2 could be feasible as an alternative fuel from a ship design point of view.

Well to wake GHG emission include production, transportation, and use of fuels on board. Traditional fuel oils have their major contribution from the use on board, but for H2-fuelled fuel cells this is eliminated. Hydrogen, ammonia and methanol have high GHG when produced from fossil sources so to make any difference, renewable energy or bio-sources are required as basis for these low-carbon alternatives.

Power plant and hydrogen storage alternatives has been evaluated with basis in a case ship with a 20 MW power plant and an endurance of app 150 nm which require a H2 storage capacity of 330 MWh or 10 tons of hydrogen. Required storage volumes for liquified H2 would be 140 m3. Required storage tank volume need to consider allowable filling level of 69%. For the case ship 2x110 m3 storage tanks are proposed.

Alternatively compressed storage at 350 bar could be used. Such system could be fitted in ten 45' containers. For such system 1000 m3 of space is required for the containers.

The case ship is designed with electric propulsion and electric power can be produced in hydrogen-powered ICE with generators or produced by PEMFC.

ICE's are so far only offered to the market by one supplier at a power range up to 2670 kW. Other suppliers have announced development project where hydrogen is tested as a blend in natural gas and such engines are today sold as "hydrogen-ready" engines. However, blend ratio of H2 is 15-25% by volume in these concepts. H2-fueled engines has potential to operate with high efficiency and low emissions. GHG emissions during operation could be close to zero for pure H2 operation but will vary dependent on technology choice. A machinery system with ICE and hydrogen as fuel would in principle be equal to a natural gas powered propulsion system. This means that basic technology is known by the industry, but specific development is required and safety issues need to be considered in all H2 ship project. H2-fuelled ICE's have been chosen in a new ship project in Norway which is scheduled to enter operation in 2024, but the availability of H2 fuelled ICE's are still limited. Additional cost for H2-fuelled ICE compared to traditional diesel engines is not clear, but at least 20-40% cost increase is expected based on cost level for natural gas powered engines but is also dependent on technology choice.

Marine Fuel cell systems are offered from several suppliers. Powercell systems consist of FC modules of 200 kW which can be linked together for MW plant systems. For a 20 MW system 100 FC units are required. Fuel cell systems for marine application in the MW range has so far not been delivered. PEM fuel cells have higher efficiencies than ICE at low load and at beginning of life. However, at high load (i.e. at rated power) the efficiency drops and is close to what could be expected on conventional ICE on the market today. Efficiency losses will occur over life time due to degradation. To obtain high efficiency fuel cell stacks must be exchanged, and a lifetime of 20000 hours is expected. These facts influence on maintenance cost which is expected to be significantly higher for a fuel cell system compared traditional ICE systems. Specific cost of PEMFC today is about 1500 €/kW which is expected to decrease the next 5-10 years. This is 3-5 times the cost of a conventional diesel engine.

Both H2 fuelled ICE's and PEMFC systems can be offered for H2 fuelled ships. TRL level for H2 fuelled ICE is 5-7 and for maritime PEMFC in the MW range the TRL level is 7 meaning that the technology is not fully commercial at the moment. The durability of the technology is unsure and high operability demand may be challenging and will add risk to a project. Good back-up solutions may be required, which can be hybrid systems with traditional ICE on renewable diesel in combination with batteries.

Potential bunkering procedure is dependent on fuel storage choice. An important constrain for the Ropax case ship in concern is limited turning time in harbor which is defined to be one hour. Required bunker amount is about 3,5 tons of H2 for each trip. CH2 bunkering could be solved by swapping containers which may be feasible on a ROPAX ship, and four containers should be swapped for each trip. Liquid storage is also an option and liquid bunkering could be from trailers or from dedicated bunker systems in the harbor. In any case liquid bunkering is time demanding due to cooldown and safety procedures and need to be developed and optimized to meet operational requirement and available time in harbor.

Rules and regulations for a hydrogen powered ship is not in place but are evolving. IMO interim guidelines for ships using fuel cell installation are approved and is a good starting point for a design, but so far a hydrogen powered ship need to be developed and approved in accordance with the alternative design approach.

Production of green hydrogen in the Nordic countries need to be developed. Nearly no green hydrogen production exists today, and hydrogen is sold at a high prices. A total of 112 projects and project plans for production of green hydrogen or ammonia in the Nordic countries has been identified. To utilize hydrogen as ship fuel green hydrogen need to be available and fuel supply system need to be an integrated part in a ship project.

# 3 The "Hope" project

## 3.1 Background

The Nordic countries aim for a carbon-neutral Nordic region. Maritime transport is one of the key remaining sectors to decarbonize and is important from a Nordic perspective due to the relatively large Nordic involvement in this industry.

The HOPE project addresses how regional shipping in the Nordic region can do the transition to become fossil-free. The project aims at clarifying the potential role of hydrogen based marine solutions in reducing the Nordic greenhouse gas emissions. In the centre of the project is a ship concept where a typical RORO/ROPAX-vessel with operating distances of around 100 nautical miles is designed for including operation with hydrogen as fuel and fuel cells for energy conversion. For this concept ship other fuel alternatives are investigated such as ammonia as fuel and the use of combustion engines as well as hybrid solutions with batteries.

Further, both the conditions for designing such a ship and the consequences are studied. The conditions include technical design and costs of fuel systems and handling, powertrains etc. but also an analysis of costs and barriers and drivers for the realisation of such a ship, such as safety issues, legal issues, and policy issues.

Strategies and the potential of producing these fuels in the Nordic region are reviewed from a shipping perspective. A realistic potential for uptake of these technologies/fuels by Nordic shipping are assessed and the benefits regarding lower emissions of greenhouse gases and air pollutants as well as impact on the sea environment are calculated.

In terms of drivers, policy options needed to accelerate uptake of hydrogen based marine solutions are assessed.

The project partners are:

- IVL Svenska Miljöinstitutet AB
- SINTEF Ocean AS
- University of Iceland
- Stena Rederi AB
- PowerCell Sweden AB

Figure 1 presents an outline of the project. The work is divided into 6 work packages with different tasks, as shown with interaction between all tasks involving all collaborating partners.

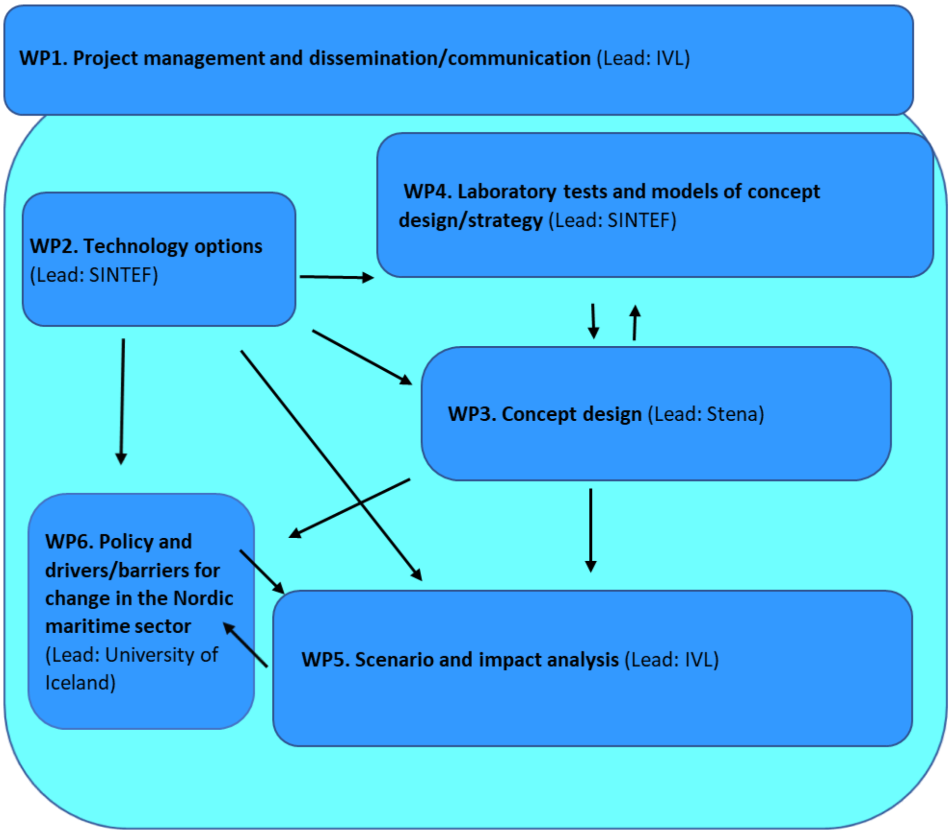



**Figure 3.1 – Organisation structure and work package definitions of the "HOPE" project**

In this report the results from WP2 "Technology Options" are reported.

## 3.2 Description of work package 2 (WP2)

Sintef Ocean has been responsible for WP2, with contributions from other partners. The objective of this WP has been to evaluate ship propulsion technology options for alternative fuels with focus on hydrogen fuelled ships.

State of the art for alternative marine fuels are outlined. Focus is on hydrogen and ammonia, but also other low carbon fuels as methanol, and biofuels incl. biomethane are discussed. To evaluate hydrogen as fuel a case ship has been defined by Stena to serve the Gothenburg – Frederikshavn route and operational requirements from Stena form basis for evaluation of fuel storage system and power trains on board.

Gaseous and liquid hydrogen storage systems are benchmarked with other low carbon fuels related to storage volumes and arrangement with focus on parameters such as energy density, physical and chemical properties and safety issues and linked to operational profile and range of the ship.

Alternative power trains for hydrogen as fuel is also assessed and FC systems, conventional ICEs and marine battery systems are addressed. Special focus is on PEMFC fuelled with hydrogen. The alternatives are assessed as single systems and in combination where relevant, with focus on efficiencies of the different powertrain alternatives, taking account of parasitic losses as well as utilization of waste heat.

A separate activity has been to evaluate fuel availability from a shipping perspective and give an overview of plans for production of renewable hydrogen and ammonia in the Nordics.

# 4 Marine fuels

## 4.1 Fossil based reference fuel

In this report low carbon fuel is defined as fuel with a significant lower carbon content than traditional fossil fuels for marine use as defined in ISO 8217. These traditional fuels are marine distillate fuels and marine residual fuels.

Typical H/C content in the reference fuels are shown in Table 4.1.

| | Carbon | Hydrogen | Nitrogen | Oxygen |
|---|---|---|---|---|
| Destillate fuel oil, (ISO 8178, DM grade) | 86,2% | 13,6% | 0,0% | 0,0% |
| Residual fuel oil , (ISO 8178, RM grade) | 86,1% | 10,9 % | 0,4 % | 0,0% |

**Table 4.1 – Typical default fuel parameters for distillate and residual fuel oil, (Ref IMO MEPC 58/23/add.I, annex 14).**

These fuels consist of hydrocarbons primarily derived from petroleum sources but may also contain hydrocarbons from renewable or synthetic sources or from co-processing of a renewable feedstock with a petroleum feedstock and should meet the ISO 8217:2017 standard.

Latest ISO 8217 edition introduces DF (Distillate FAME) grades DFA, DFZ and DFB which allow up to 7% fatty acid methyl ester(s) (FAME) content by volume. These grades are identical to the traditional DMA, DMZ and DMB grades for all other parameters except for the 7% FAME allowance. The FAME content in the DF grades should be in accordance with the requirements of EN 14214 or ASTM D6751 at the time of blending.

The regular marine fuel grades DMA, DMZ, DMB and RM (residual marine) grades shall not include FAME other than a minimum level, while DMX must be FAME-free. This minimum level has been increased to 0.5% by the ISO working group in charge of developing the latest marine fuel standards, (ISO/TC28/SC4/WG6).

## 4.2 Low-carbon fuels

Today most ship operate on various qualities of HFO and MGO with a CO2 factor of app. 3,2 kgCO2/ kg fuel. To meet environmental challenges for shipping low-carbon fuel is required. Decarbonizing marine fuel is a demanding task and will go step-wise. The first step is to use fuel with lower carbon content as natural gas which have been used as ship fuel for more than 20 years, and natural gas is believed to be a transition fuel until other lower carbon fuels are available together with technology to utilize such low carbon fuels.

Besides natural gas there are several fuels that are being evaluated as low GHG emission fuels for the maritime sector, e.g. liquid biofuels, biomethane, hydrogen gas produced by electrolysis, hydrogen gas made from natural gas with carbon capture and storage, green ammonia and methanol.

There are advantages and disadvantages to all alternative fuels which may reduce GHG emission. The fuel volumes that may be supplied are in some cases limited. Costs are in general higher than for conventional fuels and for those in early development still very uncertain. It is possible that we in the future will see a range of products used, not like today's situation based on a few products from oil refineries. For smaller ships also electricity and batteries are used as zero emission alternative.

### 4.2.1 Energy density of alternative fuels

Energy density and some characteristic data for alternative fuels are shown below. These characteristics is important to have in mind relative to handling and storage on board. Fuel characteristics described in Table 4.2 is basic input when calculating the energy density of the alternative fuels.

| Fuel | Energy density, mass (LHV) | Energy density, volume (LHV) | Lower heating value, (LHV) | Density | Storage temperature/ pressure | Boiling point |
|---|---|---|---|---|---|---|
| | MJ/kg | MJ/l | kWh/kg | kg/m3 | | °C, 1 bar) |
| H2 | 120 | 0,01 | 33,3 | 0,089 | 15 °C / 1 bar | -253 |
| CH2-350 bar | 120 | 2,8 | 33,3 | 23 | 15 °C / 350 bar | NA |
| LH2 | 120 | 8,5 | 33,3 | 71 | -253 °C / 1 bar | -253 |
| MGO | 42,7 | 36,3 | 11,9 | 850 | 15 °C / 1 bar | 160-400 |
| LNG | 49,5 | 21,8 | 13,8 | 440 | -163 °C / 1 bar | -162 |
| LPG | 46,4 | 22,7 | 12,9 | 490 | 15 °C /<15 bar | -42 |
| Ammonia, liquid | 18,6 | 12,1 | 5,2 | 653 | 15 °C / <15 bar | -33,3 |
| Methanol | 19,9 | 15,5 | 5,5 | 780 | 15 °C / 1 bar | 65 |
| Bio diesel, FAME | 37,5 | 33,2 | 10,4 | 885 | 15 °C / 1 bar | >180 |
| Bio diesel, HVO | 44,1 | 34,4 | 12,3 | 780 | 15 °C / 1 bar | >180 |

**Table 4.2 – Characteristic data of alternative fuels, /9/ .**

Figure 4.1 show the gravimetric and volumetric density of MGO and relevant low carbon fuels. For cryogenic or compressed storage large and heavy bunker tanks is required which have a significant effect on actual energy density. On fuel basis the gravimetric and volumetric density for LH2 is 120 MJ/kg and 8,5 MJ/litre respectively. Considering the LH2 storage tank itself including cold box and the filling degree of such tank when used as bunker tank on a ship, the energy density for LH2 is reduced to 11 MJ/kg or 2,2 MJ/litre.

Similar effect is seen on compressed hydrogen at 350 bar where gravimetric density is reduced to 7 MJ/kg and the volumetric density to 1,2 MJ/litre when storage is included.

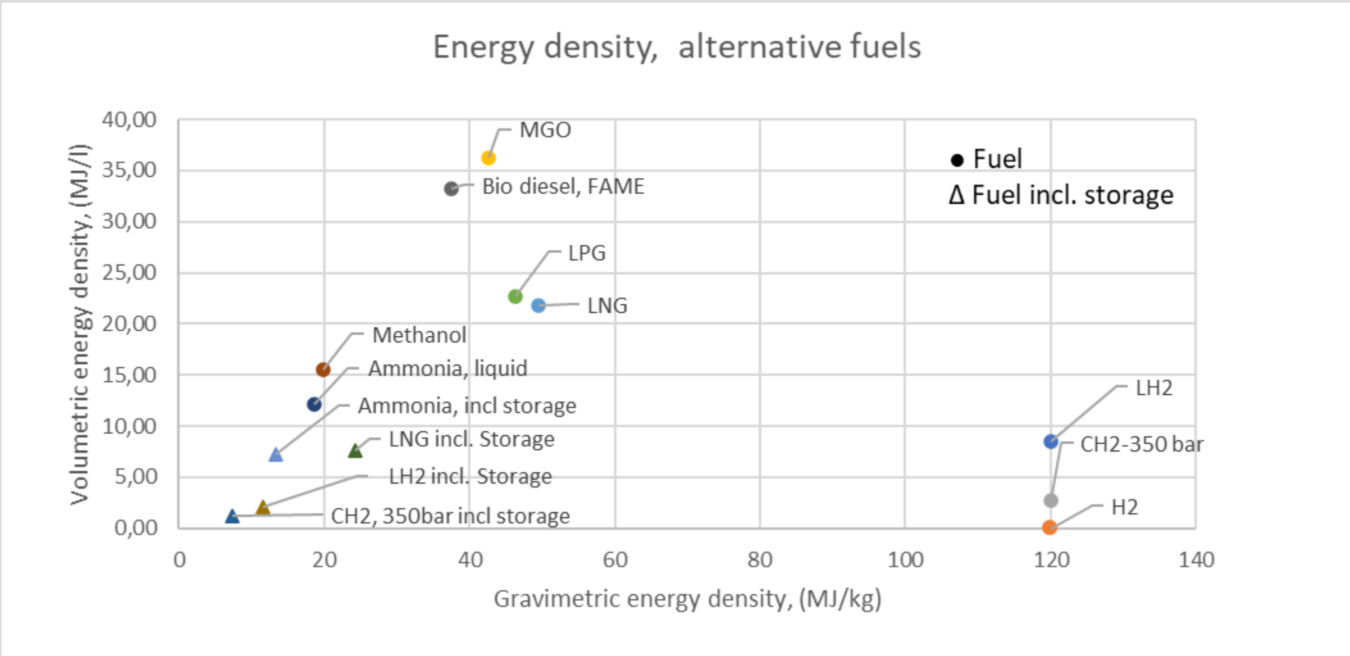



**Figure 4.1 – Energy density of alternative fuels and effects of storage tanks for cryogenic or compressed fuels. Adapted from DNV-GL 2019, /14/**

For ammonia including storage in a standard 20 bar ammonia storage tank the actual storage density is reduced to 13,3 MJ/kg and volumetric density to 7,2 MJ/litre.

For methanol it is assumed that standard tanks similar to tanks used for diesel could be used, but such tanks should be prepared for methanol storage by required coating or alternatively appropriate grade of stainless steel quality. It is assumed that no additional storage weight or volume are brought into the ship compared to MGO storage. Based on this the energy density of methanol is 19,9 MJ/kg and 15,5 MJ/litre.

The low gravimetric and volumetric density of alternative fuels when including required storage systems has great impact on the ship design and may influence on pay load and storage capacity. Relative weight and volume effects compared to MGO is illustrated in Figure 4.2. Liquified or compressed hydrogen is the most challenging fuel and may influence on the deadweight of the ship in concern. Additional weight for LH2 and $CH2_{350bar}$ is increased by about 3,5 and 6 times respectively and relative volume by 15-30 times compared to MGO as reference. Countermeasures could be to change ship main dimensions and adjust operational parameters and endurance and change bunkering frequency to fit dedicated routes.

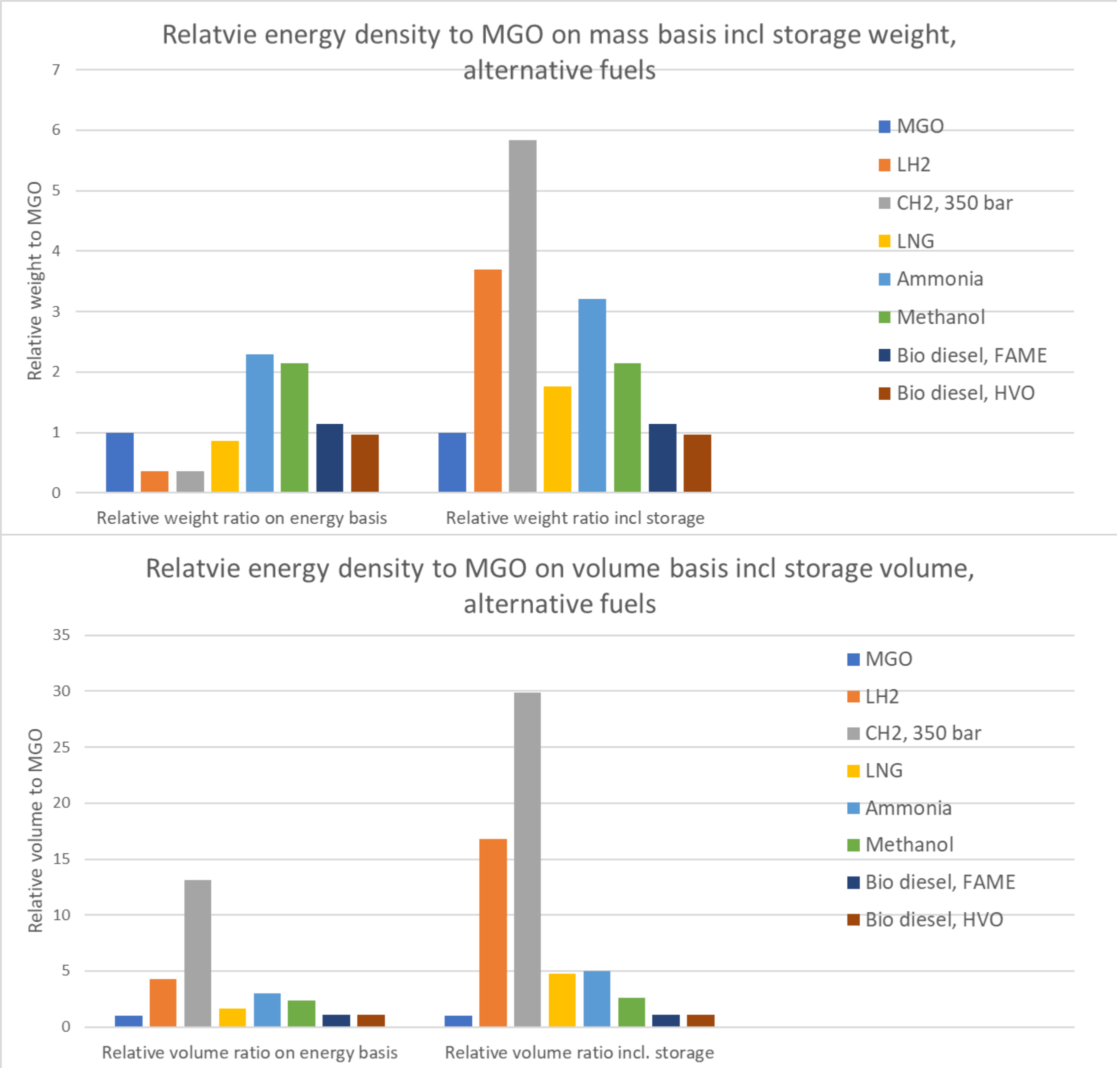


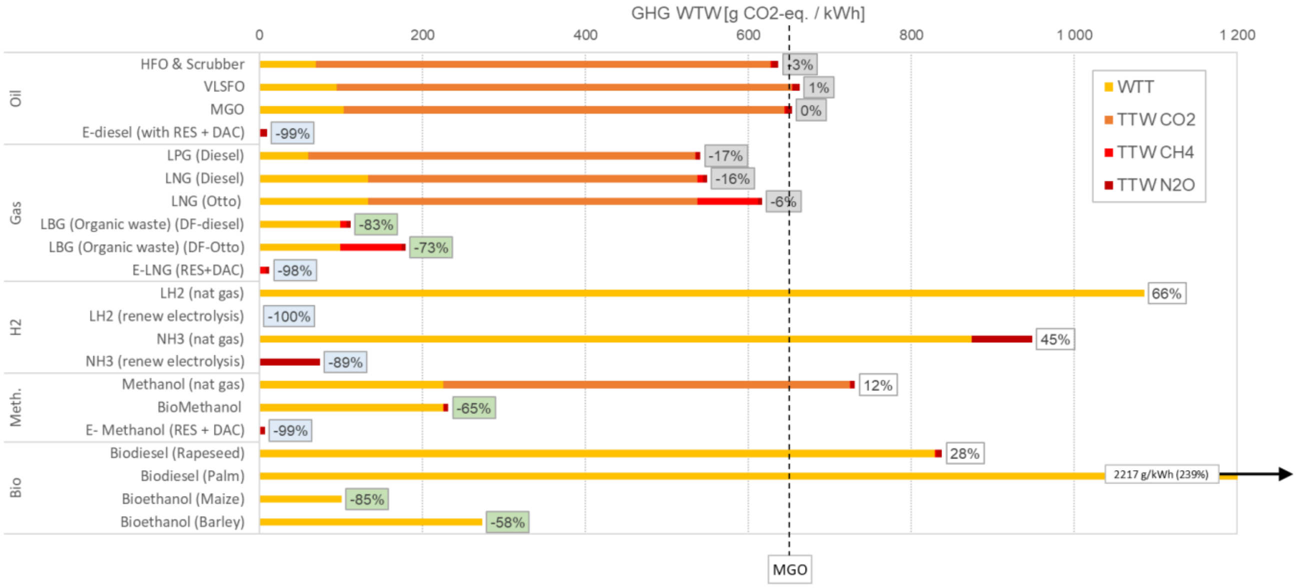

**Figure 4.2 – Relative energy density for alternative fuels compared to MGO on weight and volume basis. Left bars: On energy basis. Right bars: On energy basis including storage weight or volume.**

In addition to the fuel containment system itself, specific requirements for alternative fuels given by classification rules as in DNV Rules for ships[1] apply and will influence the overall energy density for the alternatives in question. This includes requirements to storage tanks, cofferdams, piping, material etc. related to safety issues for the fuel type in concern. Such system will occupy space and add weight to the fuel system, but these details are not considered above and not further discussed in this document.

### 4.2.2 GHG emissions for alternative fuels

GHG emissions for alternative marine fuels have been discussed and analysed in several papers and publications. It is important to include the whole value chain from fuel production to use on board the ship in such evaluations. Emissions from use is often designated Tank-to-Wake (TTW) emissions, the production and distribution are called Well-to-Tank (WTT) emissions and the total emissions is designated Well-to-Wake (WTW) emissions.

[1] DNV- Rules for classification. Ships. Edition July 2022. Part 6 Additional class notations Chapter 2 Propulsion, power generation and auxiliary systems




DAC (Carbon capture from air)
RES Renewable energy source

**Figure 4.3 – Well to Wake emission for alternative fuels, (ref.: E. Lindstad et.al, 2021) /15/**

As shown in Figure 4.3 WTW GHG emission include production, transportation and use of fuels on board. Traditional fuel oils have their major contribution from the use on board, but for H2 fuelled fuel cells this is eliminated. Hydrogen, ammonia and methanol have high GHG when produced from fossil sources. To make any difference, renewable energy or bio-sources are required as basis for these alternatives. In Figure 4.3 MGO is defined as reference fuel. The colour codes in the label of each fuel-bar refers to the origin of the energy source used for fuel production; - Blue colours indicate fuels which depend on renewable electricity to deliver the GHG reductions indicated; - Green colours indicate biofuels; -Grey colours indicates fossil fuels.

Negative values on a WTW-perspective means net reduction of GHG emission compared to reference and positive values means increased GHG. As an example, LH2 from natural gas indicate 66% increased GHG emissions in a WTW perspective and this increase is related to the production of hydrogen from natural gas (Well to tank (WTT)).

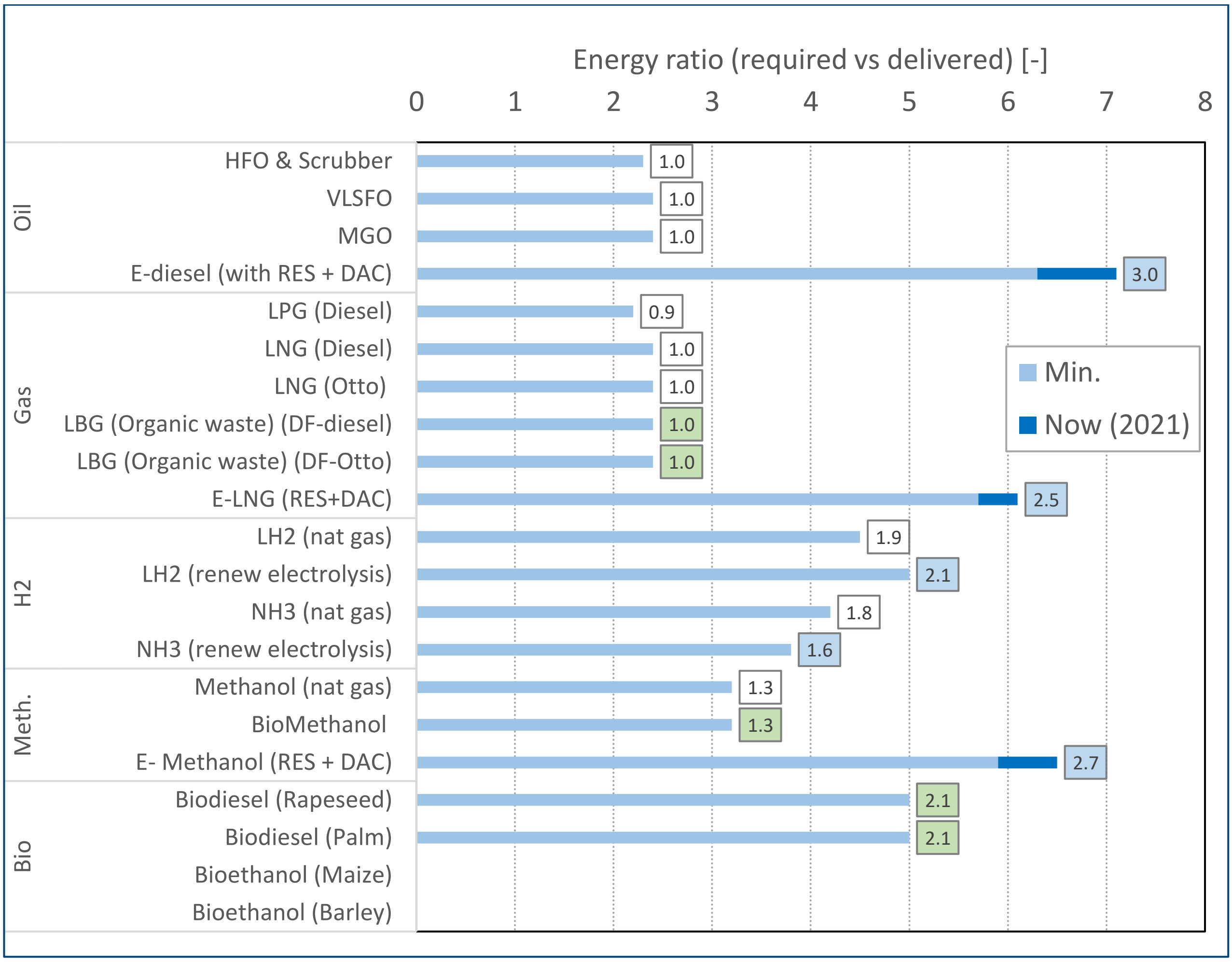
For new fuels as H2 and ammonia the efficiency of the energy converter (ICE or Fuel cell) is unsure and TTW emission for these fuels are more uncertain than for traditional fuel which use mature technology for energy conversion.

Data used for calculations of GHG factors for alternative fuels is shown in Table 4.3.

| | | | GHG Emissions | | | | | Energy usage |
|---|---|---|---|---|---|---|---|---|
| Fuel types | Engine Type | LCV | WTT | TTW, CO2 | TTW, CH4 | TTW, N2O | WTW | WTW Input/ Power Output |
| | | Mj/kg | g CO2e/MJ - 100 years | | | | | MJ/MJ |
| HFO&Scrubber | Diesel | 40,2 | 9,6 | 77,5 | 0,2 | 1,1 | 88,5 | 2,3 |
| VLSF | Diesel | 41 | 13,2 | 77,6 | 0,2 | 1,1 | 92,1 | 2,4 |
| MGO | Diesel | 42,7 | 14,4 | 75,1 | 0,2 | 1,1 | 90,8 | 2,4 |
| LNG | DF-Diesel | 49,2 | 18,5 | 56,1 | 1 | 0,7 | 76,3 | 2,4 |
| LNG | DF Otto | 49,2 | 18,5 | 56,1 | 10,4 | 0,7 | 85,7 | 2,4 |
| LPG | DF-Diesel | 46 | 8,3 | 66 | 0,2 | 0,7 | 75,2 | 2,2 |
| Liq.Hydrogen (NG) | Fuel Cell | 120 | 150,8 | 0 | 0 | 0 | 150,8 | 4,5 |
| E-Liq. Hydrogen | Fuel Cell | 120 | 0 | 0 | 0 | 0 | 0 | 5 |
| Ammonia (NG) | DF Diesel | 18,6 | 121,4 | 0 | 0 | 5,3 | 126,7 | 3,8 |
| E-Ammonia | DF Diesel | 18,6 | 0 | 0 | 0 | 5,3 | 5,3 | 4,2 |
| E-LNG | DF Ott | 49,2 | 0 | 0 | 10,4 | 0,7 | 11,1 | 6,2 |
| E-LNG | DF Diesel | 49,2 | 0 | 0 | 1 | 0,7 | 1,7 | 6,1 |
| E-Methanol | DF Diesel | 19,9 | 0 | 0 | 0,2 | 0,7 | 0,9 | 6,5 |
| E-Diesel | Diesel | 42,7 | 0 | 0 | 0,2 | 1,1 | 1,3 | 7,1 |

**Table 4.3 – WTW calculation data. GHG emission and energy requirement for production and use of alternative fuels. Adapted from /15/ .**

Another important issue which also is discussed in /15/ is the energy demand in the production and transport of the fuel relative to produced shaft power in the ship. Data is shown in Table 4.3 (right column) and illustrated in Figure 4.4.




*Minimum values (light blue) reflect future aspiration levels.

**Figure 4.4 – Energy use for alternative fuel, well to wake, relative to MGO. To deliver 1 MW shaft power based on MGO, 2,4 MW energy use is required, i.e. 1,4 MW is used for fuel production, transport and efficiency losses in system and engine. Assumption: Thermal efficiency of engine: 50%., /15/ . Labels for each bar indicate required energy ratio relative to MGO to obtain 1 MW shaft power.**

As shown in Figure 4.4 production and distribution of all alternative fuels have significant higher energy demand then fuel used by shipping today. This is important to bear in mind when choosing alternatives, and the whole value changes should be considered to make the right choice.

### 4.2.3 Natural Gas

Natural gas is available all over the world, and global trade of LNG consist of 372 million tonnes in 2021 and global liquefaction capacity is app. 460 million tonnes per year /13/ . This means that the utilisation rate of the production capacity is about 75%. Bunkering terminals for LNG are in operation in all Scandinavian countries except Iceland. LNG is produced at several places in Norway and distributed to customers in Scandinavia. LNG is also available from European suppliers. Bunkering infrastructure has developed significantly during the last 10 years and consists of fixed land terminals and ship-to-ship and truck-to-ship bunkering systems.

In general, natural gas has high energy content and good combustion properties and is well suited as fuel for ICE's. However, natural gas quality worldwide varies based on production site. A gas engine will be rated in accordance with the gas quality available, and the methane number should be in accordance with gas engine supplier's specification for a given engine rating.

| TYPICAL LNG COMPOSITION FROM MAJOR EXPORT AND BUNKER TERMINALS [Mol%] | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | | Methane | Ethane | Propane | Butane | Heavier HCs | Nitrogen | LHV [MJ/kg] | Methane |
| | | [CH4] | [C2H6] | [C3H8] | [C4H10] | [C5+] | [N2] | [MJ/kg] | Number (-) |
| Arzew | (ALG) | 87,4 | 8,6 | 2,4 | 0,1 | 0,0 | 0,4 | 49,1 | 72,7 |
| Bintulu | (MAS) | 91,2 | 4,3 | 3,0 | 1,4 | 0,0 | 0,1 | 49,4 | 70,4 |
| Bonny | (NGR) | 90,4 | 5,2 | 2,8 | 1,5 | 0,0 | 0,1 | 49,4 | 69,5 |
| Das Island | (UAE) | 84,8 | 13,4 | 1,3 | 0,3 | 0,0 | 0,2 | 49,3 | 71,2 |
| Badak | (INA) | 91,1 | 5,5 | 2,5 | 0,9 | 0,0 | 0,0 | 49,5 | 72,9 |
| Arun | (INA) | 89,3 | 7,1 | 2,2 | 1,2 | 0,0 | 0,1 | 49,4 | 70,7 |
| Kenai | (USA) | 99,8 | 0,1 | 0,0 | 0,1 | 0,0 | 0,1 | 50,0 | 98,2 |
| Lumut | (BRU) | 89,4 | 6,3 | 2,8 | 1,3 | 0,1 | 0,1 | 49,4 | 69,5 |
| Point Fortin | (TRI) | 96,2 | 3,3 | 0,4 | 0,1 | 0,0 | 0,0 | 49,9 | 87,4 |
| Ras Laffan | (QAT) | 90,1 | 6,5 | 2,3 | 0,6 | 0,0 | 0,3 | 49,3 | 73,8 |
| Skikda | (ALG) | 91,5 | 5,6 | 1,5 | 0,5 | 0,0 | 0,9 | 49,0 | 77,3 |
| Withnell | (AUS) | 89,0 | 7,3 | 2,6 | 1,0 | 0,0 | 0,1 | 49,4 | 70,6 |
| Snøhvit | (NOR) | 91,9 | 5,3 | 1,9 | 0,2 | 0,0 | 0,6 | 49,2 | 78,3 |
| Kolsnes | (NOR) | 94,6 | 3,8 | 0,6 | 0,3 | 0,1 | 0,6 | 49,3 | 83,2 |
| Bilbao | (ESP) | 91,9 | 7,0 | 0,7 | 0,2 | 0,0 | 0,2 | 49,5 | 79,8 |
| Risavika | (NOR) | 92,3 | 6,9 | 0,4 | 0,1 | 0,0 | 0,4 | 49,5 | 81,6 |
| Rotterdam | (NED) | 91,2 | 6,9 | 1,4 | 0,4 | 0,0 | 0,0 | 49,6 | 76,4 |
| Average | | 91,3 | 6,1 | 1,7 | 0,6 | 0,0 | 0,2 | 49,4 | 76,7 |

Table 4.4 - Typical LNG composition from major export terminals. Ref. gas analyses received from terminals and information adapted from /4/ .

As can be seen the methane number for the various LNG qualities varies from around 70 to 98. This is an important value to characterize the knocking resistance of the gas and is used as reference by the engine manufacturer for engine performance. Low methane number of the gas would require engine derating to avoid risk of engine knocking. Engine performance is normally given for a reference methane number, and as an example Wärtsilä DF 34 engine performance is referred to a methane number higher than 70. Engine control systems are designed to handle normal variation in gas quality for safe operation.

Today we see an increasing interest in natural gas as fuel in shipping, and gas fuelled ships are in operation worldwide. Natural gas is a competitive fuel against fuel oils and has environmental benefits with low emissions of NOx, SOx, and PM and also significantly lower CO2 emissions due to the low carbon content in natural gas with a CO2 emission factor of 2,75 kg CO2/kg fuel. The methane slip from gas fuelled engines has increased focus by IMO, EU and environmental NGO's as methane has a GHG factor 25 times higher than CO2 and will reduce the overall GHG benefit for some gas fuelled engines concepts. The methane slip issue is a challenge in particular for low pressure dual fuel (LPDF) and lean burn spark ignited (LBSI) gas engine concepts.

Several manufacturers have developed their own gas engine concepts, and natural gas fuelled engines are available in all sizes from small engines of some 100 kW to large multi-MW engines. This means that technology is available for all ship types.

### 4.2.4 Biomethane

Liquid biomethane (LBG) made from biogas through cleaning, upgrading and liquefaction is a maritime fuel, which has fuel properties similar to liquified natural gas (LNG). There is a European Standard for biomethane to be used as vehicle fuel.

Liquified biomethane (LBG) is cleaned for impurities and should consist of 96-99% methane and be in accordance with recognized standards for vehicle fuels. LBG will be stored in cryogenic tanks on board a ship and has similar storage and handling systems as LNG. When LBG is used as ship fuel it is vaporized in a heat exchanger system prior to engine and is injected as gas phase into the engine. Several engine technologies can be used such as lean burn spark ignited engines (LBSI=pure gas engines), low pressure dual fuel engines and high-pressure dual fuel engines.

By assuming biomethane with 97% methane and 3 % nitrogen the methane number is calculated close to 100 which implies good knocking resistance.

LBG and LNG can be mixed freely or can be held in separate tanks if desired by operator/owner or if necessary due to requirements from authorities.

The greenhouse gas (GHG) emission from production of biomethane depends very much on the feedstock used in the process. The EU Renewable Energy Directive (RED) have specific rules for calculating the GHG. For the use of animal manure as a feedstock, a bonus ("negative emission") is given for hence avoiding methane and nitrous oxide (N2O) from traditional manure storage and when it is spread out on the farmland. Biomethane produced on feedstock having a large percentage of manure can thus have a negative GHG emission according to the RED. Biomethane produced from other feedstocks will have a higher GHG emission, and in worst case higher than marine gas oil if feedstocks result in land use.

Methane slip from the biogas plant is also a part of the total GHG emission. It is known that this is very variable dependent on technology used and operational factors. An IEA report (Liebetrau, 2017, /5/ ) forms a good starting point for evaluating biogas plants.

There will be a competition for sustainable biomethane between sectors like road, rail, conversion to aviation fuel, industry and shipping. There is an unused sustainable feedstock potential and IEA (2020, /6/ ) has estimated the world potential to be 20% of today's natural gas consumption.

The main producer of biogas in Scandinavia is Denmark followed by Sweden, Finland and Norway.

Biogas status is from 2020/21 and volumes may have changed today.

| | |
|---|---|
| Denmark: | 5,8 TWh |
| Sweden: | 2,2 TWh |
| Finland: | 0,8 TWh |
| Norway: | 0,7 TWh (2021) |

To date, most of the produced biogas in Denmark is used in electricity production. About 2,6 TWh is upgraded to biomethane and can be used as transportation fuel and is delivered to the natural gas grid. /24/

In Sweden 65% of the produced biogas is upgraded to biomethane and can be used as fuel in combustion engines, /10/ .  Liquid biomethane is also available from several plants in Sweden.

According to Finnish Biocycle and Biogas Association, /11/ the biomethane production was app. 156 GWh in 2021 which is 21% of total production.

About 40% of Norwegian production is upgraded to biomethane or about 280 GWh, /23/ . This is available as CBG and LBG in Norway today and only a few plants are producing biomethane for transportation.

### 4.2.5 Liquid marine biofuels

Biofuels are produced from various biologic resources as plant-based sugar, oils and terpenes and animal fat waste, /1/ and goes through various processes in several stages before it reaches an accepted fuel quality which can be used in combustion engines. Relevant information and overview of biofuel technology can be found on ETIP Bioenergy homepage, http://www.etipbioenergy.eu/, /3/

The European standards organization, CEN, has published a FAME standard (EN 14214) that establishes specifications for biodiesel use as either: (i) a final fuel in engines designed or adapted for biodiesel use; or (ii) a blendstock for conventional diesel fuel. Similarly, ASTM International has established specifications for neat biodiesel (ASTM D 6751) but only for use as a blending component, not as a final fuel, /2/ .

Special concern related to biodiesel are:

- Stability, oxidation of fuel
- Low temperature behaviour
- Hydroscopic, potential for high water content
- Deposit formation in injection system
- Filtration clogging
- Impact on natural and nitrile rubber seals in fuel system
- Impact on metals as brass, bronze, copper, lead and zink to cause sediments and filter plugging

For land-based use, engine and vehicle manufacturers have elaborated on these concerns as described in /2/ .

In the IEA report "Biofuels for the marine shipping sector" /7/ potential biofuel for marine application is addressed. The report gives a comprehensive overview of ship types and propulsion, current marine fuels and potential for biofuels in shipping. The main conclusions are that it is a potentially large market for biofuels in the shipping sector, but technical and logistic issues need to be resolved before biofuels can be introduced at a larger scale, and a closer collaboration between biofuel producers, engine developers and ship owners is recommended as a path forward. The report clearly states that GHG savings from biofuel is dependent on production process and origin of the fuel in concern. A big advantage of biofuels is zero or low sulphur content which make this fuel compliant with existing regulations. Low sulphur content in fuel will also influence emissions of particle matter (PM) which will be significantly reduced on mass basis. Effects on NOx and other emissions is not discussed, but NOx emissions can increase for some biofuel qualities. Biofuel for marine application is one measure to meet IMO GHG goals in 2030 and 2050 with potentials for 40-70 % reduction in GHG from shipping

Drop-in biofuels are defined as liquid bio-hydrocarbons that are functionally equivalent to petroleum-derived fuels and fully compatible with existing petroleum infrastructure. By definition, they must meet the following bulk property requirements: miscibility with petroleum fuels, compatibility with performance specifications, good storability, transportability with existing logistics structures and usability within existing engines. Additionally, they are also mostly compatible with fuel injection systems already in place, /1/ .

HVO is an example of drop in biofuels which could substitute auto diesel or MGO. Such qualities are also known as renewable diesel. Several demonstrators have used this fuel as a blend with MGO or as B100 quality. Biofuels have also been used in demonstrator as blends with low sulphur fuel oil. Several ships and engine types have been involved in these demonstrators.

Current ISO standard (ISO 8217) do not allow FAME in residual oil and limit the blend to 7% in distillates. Engine manufacturer are reluctant to use biofuels for their engines as increased risk of failure may be the consequence in case of fuel incompatibility, etc. Several risk reduction measures are suggested, such as system modification and operation procedures. An engine validation test will be required in advance of a full-scale demonstration on a ship. Test with non-ISO compliance fuel will imply a warranty breach and a transfer of responsibility from OEM to fuel supplier or ship owners in case of failure.

Biofuel availability and price is uncertain. Increased use in land and air transport will reduce availability. The maritime fuel marked may be unattractive to the biofuel makers due to the traditionally low fuel prices in shipping.

Biofuels have been used in land-based transportation, and the RED II directive will increase the use of biofuel among EU member states. Technical obstacles and quality issues related to biofuel is well known and can be handled, also for marine application. Fuel compatibility and technical modifications on ships are issues to be addressed to ensure safe operation. Resolving these issues is foreseen to require close cooperation between ship owner, engine manufacturers fuel suppliers and others.

GHG factors for various types of biofuel is established in RED II, and some renewable biodiesel have a GHG saving of up to 90%. This means that with a blend of 45%, the IMO GHG goals for 2030 can be met.

World production of biofuels (biodiesel and renewable diesel) are 50-54 mill ton per year in 2022, /26/ . More details on biofuels are not within the scope of this report.

### 4.2.6 Hydrogen

Hydrogen has been introduced as a potential carbon free fuel for land-based transport but also as fuel for the maritime sector.

The special properties of hydrogen make it challenging to use as fuels in ships, and this is particularly related to energy density and safety issues. Hydrogen can be stores in compressed or liquid form and a process diagram is shown in Figure 4.5. Main safety issues are related to potential leakage, ignitability properties in air and large flammability range in air (4-75%).

Rules and regulations for hydrogen as fuel is not in place, and an alternative design approach is required when utilizing hydrogen as a fuel on ships.

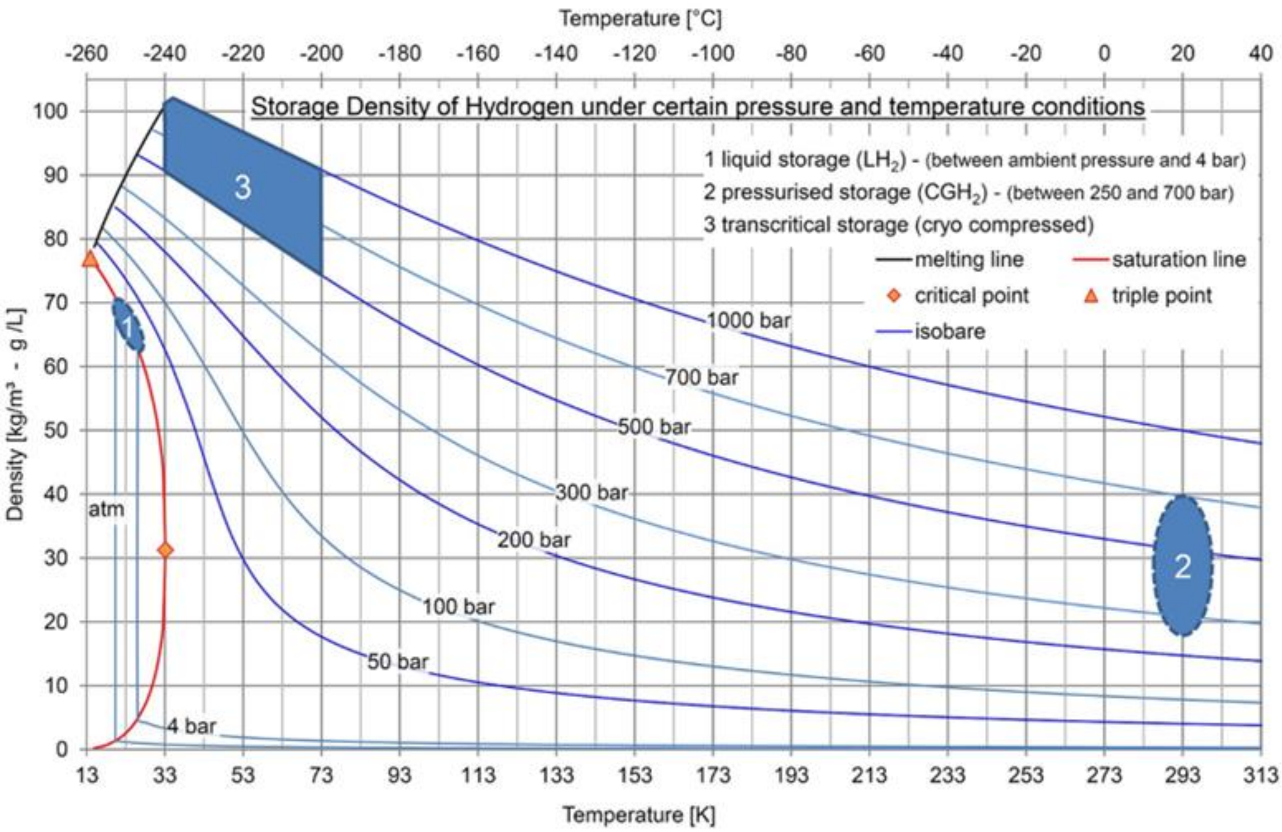



**Figure 4.5 – Storage density of hydrogen, https://www.ilkdresden.de/en/service/research-and-development/project/hydrogen-test-area-at-ilk-dresden/**

Hydrogen is not commercially available as marine fuel today but used in process and chemical industry. Today, hydrogen is mainly produced from thermochemical conversion (reforming) of natural gas (almost 67 percent). Annual world production is app. 70 million tonnes /17/ and European production capacity is app. 11,5 mill tons/year with a utilisation of app. 76%, /34/ .

In Norway the annual production is app. 225 000 tonnes, /18/ . Domestic use in Norway is in fertiliser production, methanol production and other industry.

The production and use of hydrogen in Sweden amounts to approximately 180,000 tonnes of hydrogen per year (equivalent to about 6 TWh/year hydrogen), /16/ . Almost all hydrogen produced in Sweden today is used close to where it is produced.

In Denmark the production of hydrogen is about 18000 tons, and mostly used in oil refineries, (97%), /19/

Total hydrogen production in Finland is estimated to be about 150 000 t/a (5,0 TWh). Less than 1 % is produced via water electrolysis, /21/

In Iceland hydrogen there were nearly no use of hydrogen in 2020. /25/

Total hydrogen production in Scandinavia amount for app. 570 000 tons a year or less than 1% of world production.

Liquified H2 is not available in Scandinavian countries today and world production is app. 350 tonnes/day. European LH2 production capacity is about 20 tonnes/day. (2021). Main source for H2 production is natural gas and about 5% of total word production is green H2 produced from electrolysis of water.

Hydrogen is not an energy source and have to be produced. To make hydrogen available as an attractive fuel large investment in production and infrastructure is required. In the Scandinavian countries several hydrogen projects are presented, and this is future discussed in chapter 9.

Green hydrogen has the potential to contribute to lower GHG gasses from the transportation sector in general and also for ships. The feasibility of H2 as ship fuel for larger ships is challenging due to fuel properties and available technology, and this project will make conceptual design of a ROPAX ship to evaluate gaps and challenges which need to be solved.

Hydrogen has been used in combustion engines in the automotive industry in cars and buses. However main energy converter for H2 in cars and buses seems to be fuel cells.

In 2020 an ICE engine from Belgian company BeHydro was launched, /29/ . The engine is offered as dual fuel engine operating on 25% diesel and 75 % H2 and as a spark ignited engine operating on 100% H2 and in a power range from 1000-2670 kW in 6,8,12 or 16 cylinder configuration.

H2 powered ship engines are not commonly available today, but engine manufacturer Wärtsilä has announced a development program to utilize H2 as fuel for their gas engines. Their aim is to develop the combustion process in their gas engines to enable them to burn 100% H2. In previous research they have run their engines on blends of H2 and natural gas with up to 60% H2 concentration, /8/ . Bergen Engines has announced successfully test results from running H2-natural gas blends up to 15% on volume basis and has entered contracts to supply gen-sets running on blends of H2 and natural gas./27/ /28/ . MAN Energy Solution has developed a gen-set running on 20% vol H2 and aims for 100% H2 during this decade,/32/ .

H2 powered fuel cells have been used in several ship demonstration projects. Mostly smaller ships and energy systems have been demonstrated. Systems in the MW range have been designed, however such systems are still not in operation in any ships.

### 4.2.7 Ammonia

Ammonia is a H2 carrier and could be used as fuel in ICE and FC. Ammonia has bad combustion properties /22/ and is toxic in small concentration which rise safety questions which must be handled related to handling and transport.

Global production of ammonia is about 180 million tonnes and world trade market are about 20 million tonnes, (ref. Yara). Yara has 25% market share of the global trade.

Ammonia is transported in large quantities at sea and on land, and production, handling and transport is regarded mature technology. However, this is special transport and required several safety measures to handle the risk associated with this product.

Using ammonia as a fuel on ship close to populated areas rise several issues related to risk which need to be understood and dealt with. This is not a topic for this report.

The traditional way to produce ammonia today is by reforming natural gas which have a high energy demand and CO2 footprint. State-of-the-art production of ammonia gives 85 kgCO2/GJ compared to about 88 kgCO2/GJ for LS-MGO (DNVGL, 2020). No significant CO2 reductions apply by using "brown" ammonia as a hydrogen carrier based on natural gas reforming. To be considered as a low carbon fuel, renewable sources must be used for production as illustrated in Figure 4.6.

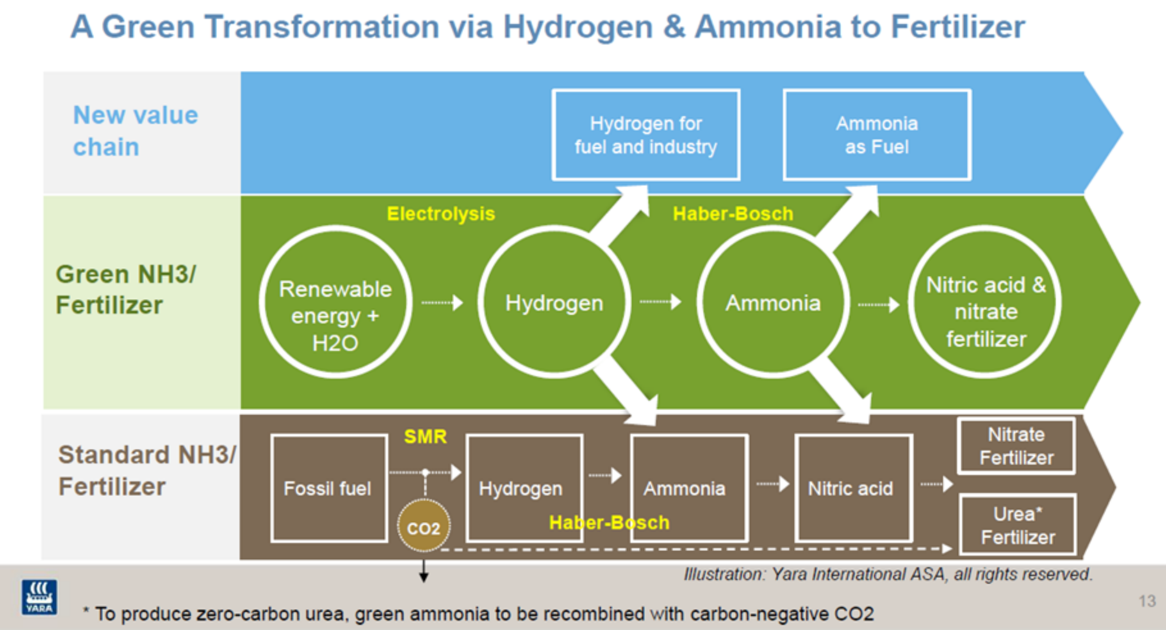



**Figure 4.6 - Possible renewable production chain for ammonia, ref Yara.**

Assuming renewable energy as source for H2 production, green ammonia can be produced and offered as fuel for transportation.

Today no engine manufacturer supply ammonia fuelled engines to the maritime market. MAN and Wartsila have development projects to utilize NH3 as a fuel in ICEs, and other engine manufacturers are investigating the potentials for ammonia as a carbon free fuel on ships. Dedicated bunker tanks is required for ammonia which will be stored in liquid phase at low pressure on board. Material quality for all systems in contact with ammonia should be carefully chosen for safe operation. There are also development project for ammonia fuelled SOFC, but maritime systems has not yet been demonstrated.

### 4.2.8 Methanol

Methanol may be a low or zero carbon fuel dependant on how it is produced. Methanol ($CH_3OH$) is a liquid chemical and can be stored in fuel tanks at atmospheric pressure like bunker fuel oil.

Today, methanol is typically produced on an industrial scale using natural gas as the principal feedstock by steam reforming of natural gas to make synthesis gas and further conversion into liquid methanol. Total annual production of methanol was 98 mill ton in 2019 mostly based on fossil sources. Methanol from renewable sources counts for only 0,2 million tons annually, /12/ . This can be bio-methanol produced from bio-mass or e-methanol produced from CO2 capture and green hydrogen.

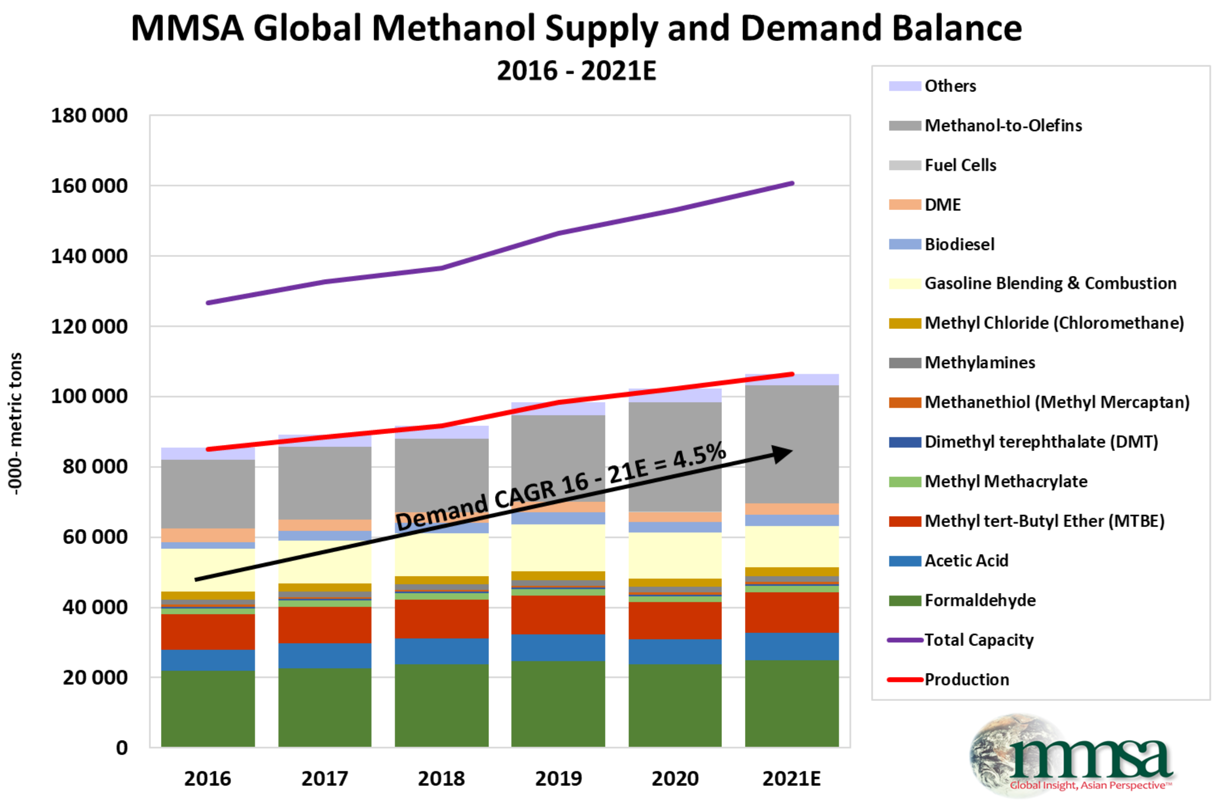



**Figure 4.7 – Global Methanol supply and demand balance, https://www.methanol.org/methanol-price-supply-demand/**

Figure 4.7 indicate total production capacity (purple line) and actual consumption and main product from methanol worldwide.

Methanol can be used as fuel in large ship engines. Marine demonstration project has been run and methanol has been used as fuel on methanol carriers in commercial projects. Two-stroke and four stroke engines have been demonstrated in these project and technology for handling and using methanol as fuel in ships is known.

# 5 Definition of system scope for this study

## 5.1 Fuel and power train system

The aim of this study is to investigate power train alternatives depending on fuel choice. Of special concern is the choice of energy conversion system which can be traditional ICE or fuel cells depending on fuel. A feasible approach for such investigation is to "follow the energy" as illustrated in Figure 5.1 as follows:

- Energy supply and storage system
  - Land transportation
  - Shore storage
  - Shore to ship transfer
  - Onboard storage
  - Storage to energy converter
- Fuel system
  - Fuel conditioning system
  - Fuel safety systems
- Energy Converter
  - PEM Fuel cell
  - ICE
- Energy converter to electric distribution system, electric motor- mechanical power to propulsors
  - Electric distribution system, motors and propulsors assumed to be available technology

This project focus on the ship concept and systems on board the ship. Hence, land distribution and storage of alternative fuels is not further discussed.

Fuel and power system should be designed to meet operational requirements as speed and endurance and the operational profile of the ship will define these requirements. Preferred energy converter will be PEMFC, but H2 powered ICE will also be discussed.

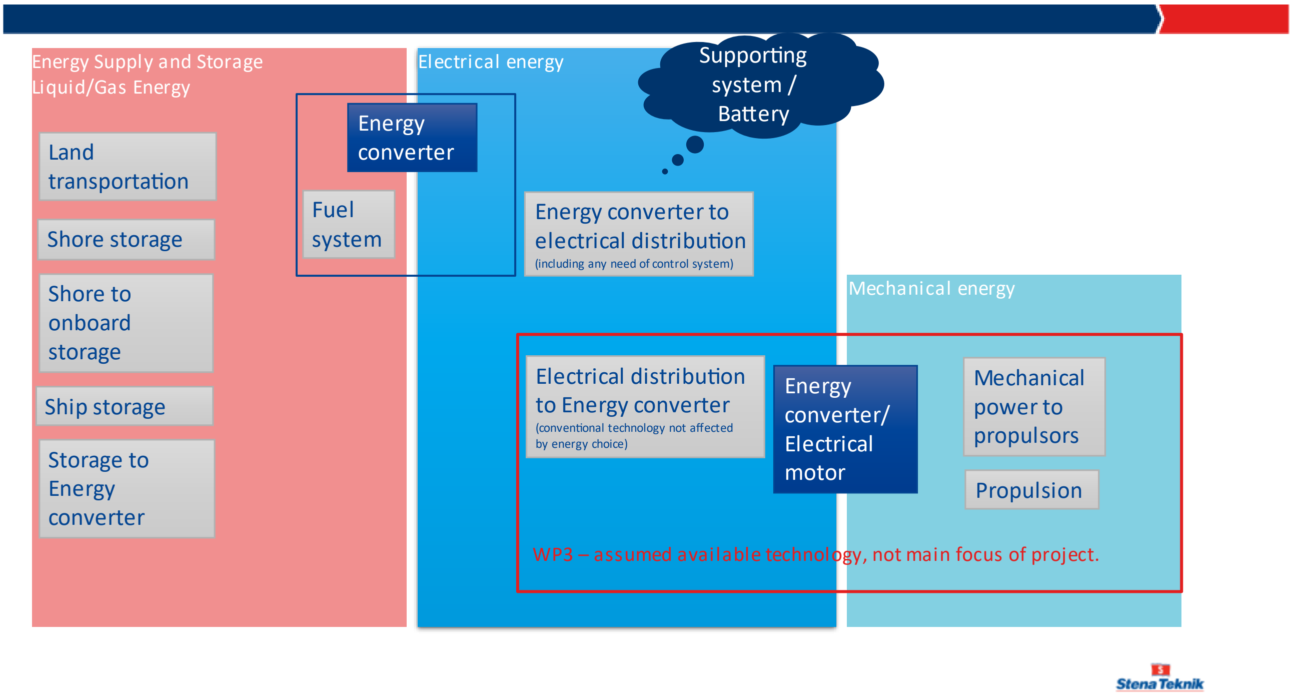



**Figure 5.1 – System boundary for power train investigation, ref. Stena Teknik.**

## 5.2 Case description

### 5.2.1 Operation profile

The case ship in this project is a ROPAX vessel and based on existing route the following operational profile has been defined.

- Route: Gothenburg-Frederikshavn
- Sailing distance: 50,5 nautical miles, (nm) (Measured from map)
- Sailing Schedule: 3 h 15 min sailing, (based on route schedule information)
- Harbour 90 min.

Sailing route is illustrated in Figure 5.2

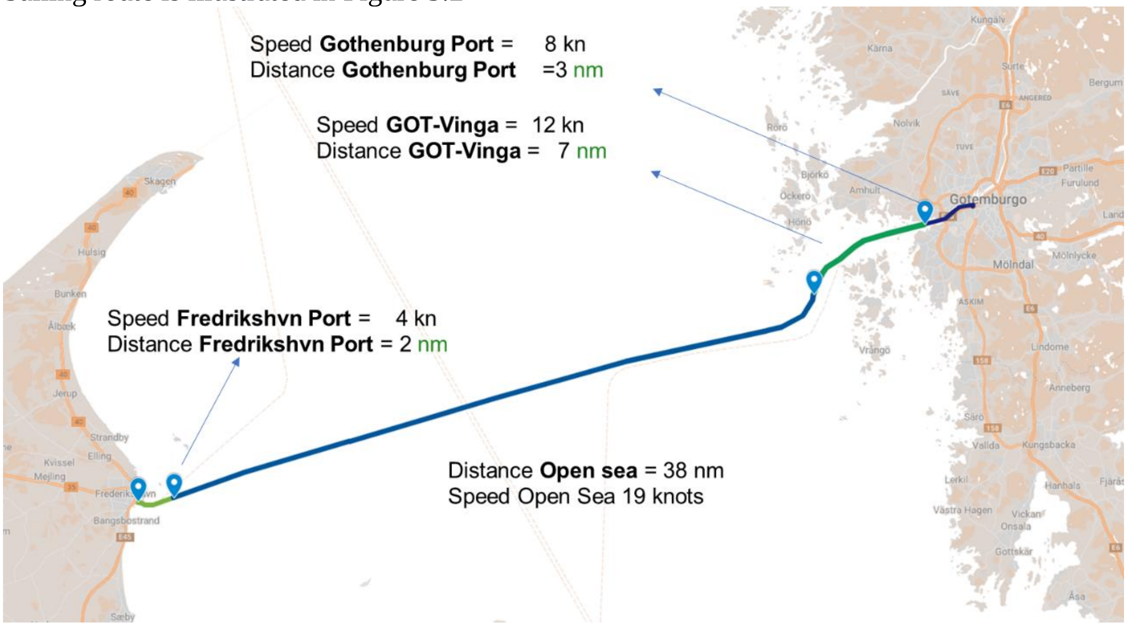



**Figure 5.2 - Sailing route for case study, Gothenburg-Frederikshavn**

**Table 5.1 – Operational profile, sailing distance and speed in various operational modes**

| | Distance | | Speed | Time | |
|---|---|---|---|---|---|
| Op. Mode | nm | km | kn | h | min |
| Service speed | 38,0 | 86,1 | 19 | 2,0 | 120 |
| Slow speed Got | 3,0 | 1,6 | 8 | 0,4 | 23 |
| Slow speed Got-Vinga | 7,0 | 3,8 | 12 | 0,6 | 35 |
| Slow speed Fred | 2,0 | 1,1 | 4 | 0,5 | 30 |
| Harbour, average | | | | 1,5 | 90 |
| Trip duration, ex harbour | 50,0 | | | 3,5 | 208 |
| Total distance | 50 | 92,6 | | | |
| nm= | 1,852 | km | | | |

Assumed speed power curve for similar ship type is used as basis.

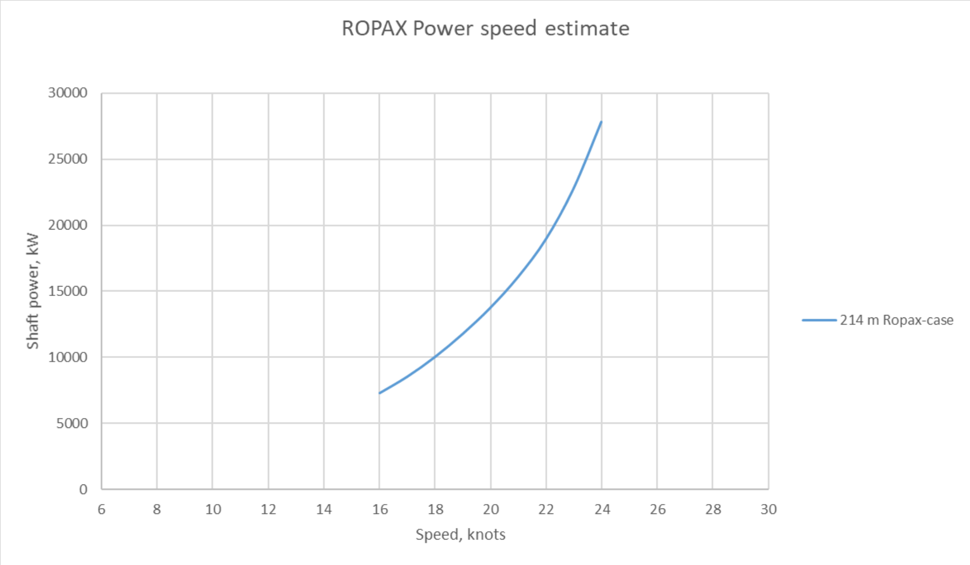



**Figure 5.3 – RoPax speed-power curve, incl. 12% sea margin**

Based on operational profile of case ship the overall energy storage on board for propulsion is estimated to be 300 MWh.

Average speed for the case ship would be 18-19 knots for the planned route, which could be obtained with a propulsion power of app. 10 MW. Typical design speeds for this kind of ships on general basis is 22-23 knots with a propulsion power of 18-25 MW. But by accepting reduced performance for the dedicated case ship design, significant reduction in power demand is achieved.

Assumed installed propulsion power for the case ship would be 16-17 MW to obtain margins and flexibility giving a design speed of app 21 knots.

### 5.2.2 Fuel consumption – Endurance - fuel storage on board

Reference ship will be calculated based on a design requirement with a total energy availability in fuel for propulsion of 300 MWh based on hydrogen.

To count for hotel power of 2 MW continuously use additional fuel is required. Based on this condition design specification for fuel quantities is as follows:

**Table 5.2 - Design basis for H2 storage in case ship**

| **Design basis, hydrogen storage** | | |
|---|---|---|
| Mechanical energy on shaft | 150 | MWh |
| Efficiency of Fuel cell, design basis | 50 | % |
| Energy in fuel for propulsion | 300 | MWh |
| Hotel and margin: | 32 | MWh |
| Sum hydrogen storage | 332 | MWh |
| Required H2 storage: | 10,0 | ton |

### 5.2.3 Bunkering frequency

Bunkering would be required for each trip, alternatively once for a return trip. Assuming bunkering for each trip, the estimated energy consumption is equivalent to 3,5 tons of H2, and this energy amount should be bunkered during maximum 90 minutes in harbour. Shorter time in harbour (=60 min) may be required from a commercial perspective, resulting in reduced time for bunkering. More details on storage and bunkering alternatives are discussed below.

# 6 Fuel handling and storage options

## 6.1 Hydrogen as fuel

Based on case ship design requirements on endurance and propulsion power, the fuel volume has been estimated.

Bunkering frequency would be every 50 nm, but fuel storage should be dimensioned with spare capacity. Design consideration assume 150 nm endurance for this ship, and energy storage capacity equivalent to 332 MWh of hydrogen. Based on such operation profile bunkering capacity of 10 tons of H2 is required.

### 6.1.1 Compressed hydrogen

Compressed storage of 10 tons of hydrogen requires a storage volume of app. 400 m3 at 350 bar storage pressure. Lower storage pressure requires significant larger volumes (Figure 6.1).

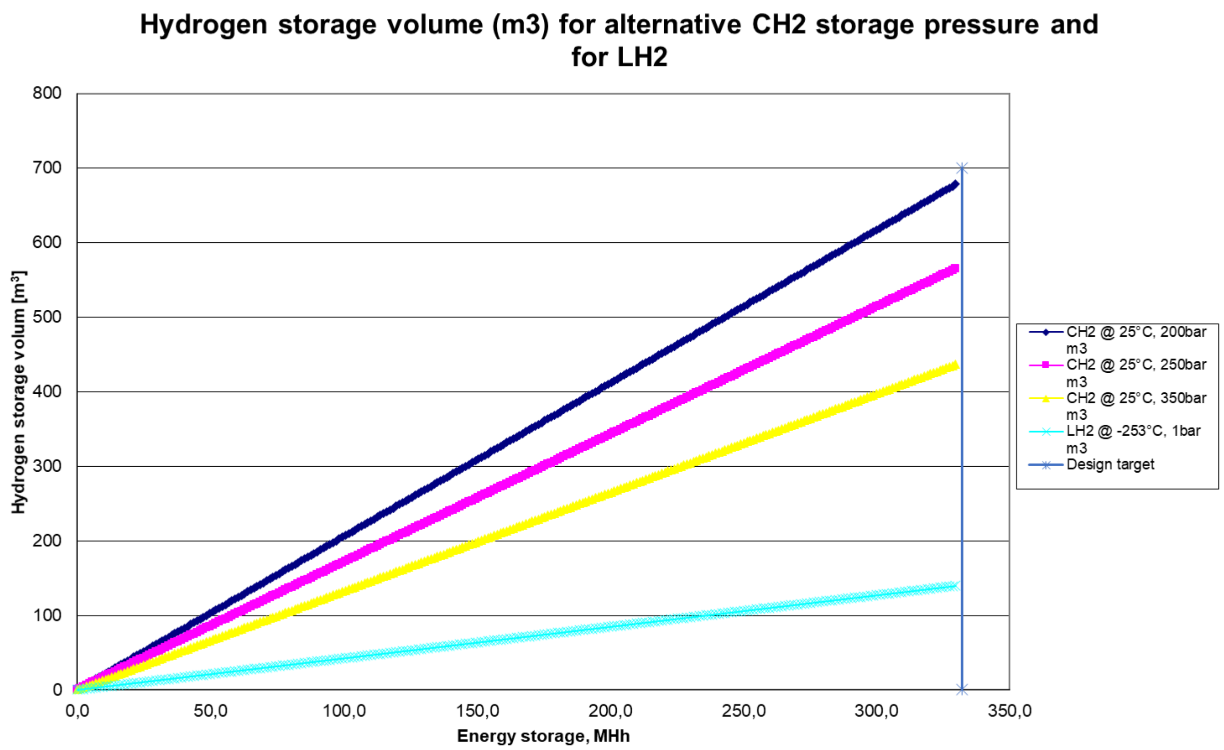



**Figure 6.1 – Required storage volumes for 10 tons of hydrogen at alternative storage pressure.**

Potential suppliers of pressure storage systems could be:

- Hexagon
- UMO Composite

Assuming pressure vessels from UMO as a design basis data is shown below.

A 45' ISO high cube container has capacity to store app. 1000 kg of H2 at 350 bars in 22 individual pressure vessels. Ten (10) such containers are required for storage of the required amount of H2 for the design case. Footprint of one 45' container is 13,8*2,5 m.

Weight of a single pressure vessel is in the range of 500 kg. Total weight of 22 pressure vessels is 11000 kg. Tare weight of a 45' iso container is app. 5000 kg. In addition, mounting frames and internal pipes and fittings is required giving a weight estimate of 16000 kg for a single container or 160 tons for the total storage system including fuel.

It is assumed that using ISO-container for CH2 storage will be an efficient way for installation of the gas cylinders on board and give alternatives on how to bunker the ship. The ISO-container reference also gives good indication of required volume in the design process. In the case compressed H2 is found feasible, more detailed design is required on how to bundle and install these in a ship (which is mainly outside the scope of this project).

Based on these parameters the following design parameters is defined related to CH2 storage at 350 bar pressure:

**Table 6.1 - Design basis, compressed H2 storage at 350 bar based on UMO Advanced Composite, (UAC) cylinders.**

| CH2 Storage cylinders | | Ref, https://www.uac.no/ |
|---|---|---|
| Storage pressure, bar | 350 | |
| Total storage volume, (water volume), m3 | 440 | |
| No of cylinders | 220 | Approximate |
| Single cylinder volume, liter | 1925 | |
| Estimate cylinder weight, kg | 500 | Per cylinder |
| **Total weight, cylinders, kg** | **110000** | |
| **ISO 45' container data** | | |
| Iso 45' container dimensions, (LxBxH) m3. (High cube) | 13,8x2,5x2,9 (=100 $m^3$) | Footprint, 34,5 m2 |
| Estimate 45' ISO container weight incl mounting frames, pipes and valves kg | 5000 | |
| Number of Iso 45'container stack with 22 cylinders | 10 | |
| Total weight – containers, kg | 50000 | |
| Total weight, CH2 storage system 350 bar, kg | 160000 | |

Pressure cylinders can be stacked and placed in ISO containers for transportation. Example on stacking cylinders in height from UAC is shown in Figure 6.2.

**Figure 6.2 - Example, H2 pressure cylinder arrangement, ref.www.uac.no**

As shown each cylinder has valve train arrangement. This normally consist of safety arrangement for each cylinder as pressure relief system which could be blast disk for overpressure and temperature fuse in case of fire. Each cylinder is further connected to a gas piping system.

Example of alternative arrangement of pressure cylinders are shown in Figure 6.3. These cylinders are smaller and arranged in vertical racks. A cylinder size of 350 liter has storage capacity of 8,4 kg H2 at 350 bar, meaning that app. 1190 single cylinders are required for storage of 10 tons of H2 which is the design basis for the case ship. Such arrangement needs eleven 45' containers with 108 cylinders in each container.


**Figure 6.3 - Arrangement of pressure cylinder in 45' container. Ref.: https://hexagongroup.com/companies/hexagon-purus**

### 6.1.2 Bunkering procedure for compressed H2

Compressed hydrogen can be bunkered in three ways:

- Swapping CH2 containers
- Bunkering from compressor system (compressed storage)
- Bunkering from LH2 system (LCH2 system)

Swapping containers for our case ship mean that four containers should be swapped after each trip, (1 ton of H2 per container). As this is a ROPAX ship this may be a feasible solution. Swapping containers meet operational challenges and safety issues related to handling and connection/disconnection of containers. Available time for swapping should be sufficient as harbour time is 60-90 minutes.

Bunkering from compressors need a storage system or continuous production of H2 close to ferry terminal and a bunkering system for gas transfer. Compressor system need high capacity and temperature control to meet storage requirements and will be large units. Bunkering CH2 at 350 bars via compressor close to quey should be carefully designed to make them feasible within the available time for bunkering the ship. Filling technology for cars and trucks has been demonstrated but ship systems need significantly higher capacity to be able to bunker large quantities in a short time period.

Bunkering system based on liquid hydrogen (LCH2-system) is a third way of refuelling the ship with compressed H2. Such system will in principle be equal to LCNG system commonly used in filling stations for vehicles, and would require liquid storage, pump and evaporation system and gas distribution system on the quey side. As for compressor bunkering dimensions must be sufficient to meet operational requirements which means larger systems than used in the automotive industry today.

Bunkering solutions for two Norwegian project (With Orca, bulk ship[2] and Torghatten H2 RoPax Ferries[3]) is based on compressed H2 storage. For With Orca the bunkering procedure is based on swapping of containers. Detailed bunkering procedure for the new Torghatten ferries is not described but daily bunkering will be required.

Hydrogen will be stored in compressed form in replaceable containers, and bunkering will take place by empty containers being lifted off the ship and replaced with full ones.

Any details and requirement to CH2 bunkering systems are not further discussed in this report.

### 6.1.3 Liquified hydrogen

For dimensioning LH2 fuel storage tanks the following requirements apply:

- Tank filling level: 69%
- Storage redundancy, two independent tanks.

Based on MAN solution the following tank design apply:

- Vacuum insulated double tank
- Footprint: (LxH): 17,4 x 4,1 m2.

[2] https://kommunikasjon.ntb.no/pressemelding/the-worlds-first-hydrogen---powered-cargo-ship-receives-nok-104-million-in-support-from-enova?publisherId=17848299&releaseId=17941901
[3] https://hydrogen24.no/2022/04/28/torghatten-nord-mener-trykksatt-hydrogen-er-billigst-og-enklest/

- Weight/ water volume: 50500 kg, 110 m2
- Cold box for process and safety equipment

For the case ship in concern the LH2 storage parameters described in Table 6.2 apply.

**Table 6.2 - Design basis, liquified H2 storage.**

| | | |
|---|---|---|
| LH2 Storage tanks | | |
| Storage pressure, bar | 10 | |
| Total storage volume, (water volume), m3 | 220 | Two tanks |
| Tank filling level | 69% | |
| No of tanks | 2 | |
| Estimate tank weight incl. cold box, kg | 50500 | Per tank |
| **Total weight, LH2 storage system, kg** | **101000** | |

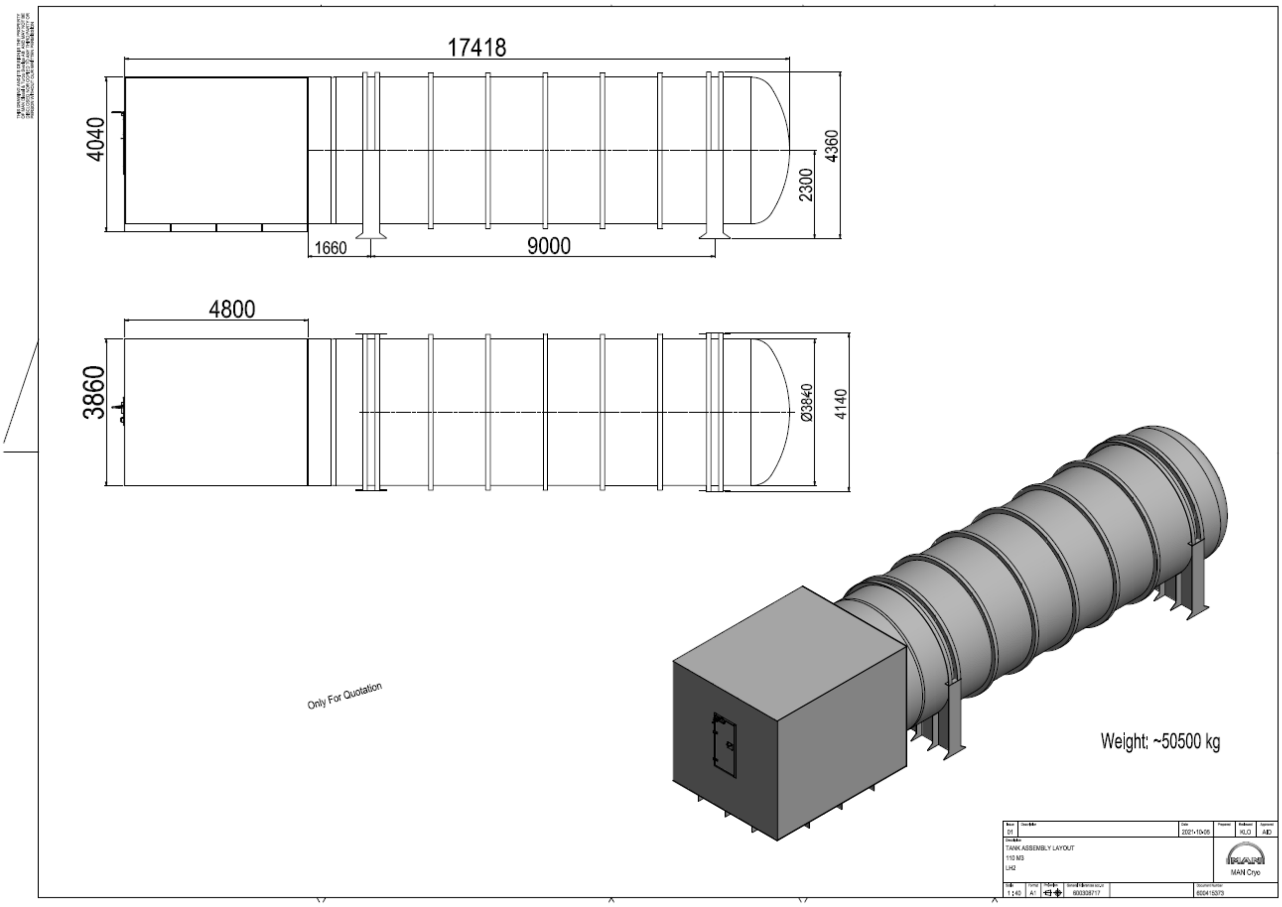


**Figure 6.4 - LH2 storage tank, 110 m3, Source MAN Cryo**

For the case ship in concern redundant tank system is required. The MAN Cryo LH2 storage tanks (Figure 6.4) is approved by class, and the main safety philosophy follows principles of LNG storage systems:

- Industry standard for cryogenic fluid handling, i.e. double hull tanks where outer hull is considered as secondary barrier
- Volatile gas handling; Leak barrier, double piping for leakage prevention
- Inert system with nitrogen, avoid combustible mixture in case of leakage
- H2 detection system, alarm and shutdown system
- Automatic control, system shutdown and venting to safe location
- Potential leak handling by ventilation to safe area, (vent mast).

Principle arrangement of LH2 storage based on standard industry cryogenic storage tank design is shown in Figure 6.5.

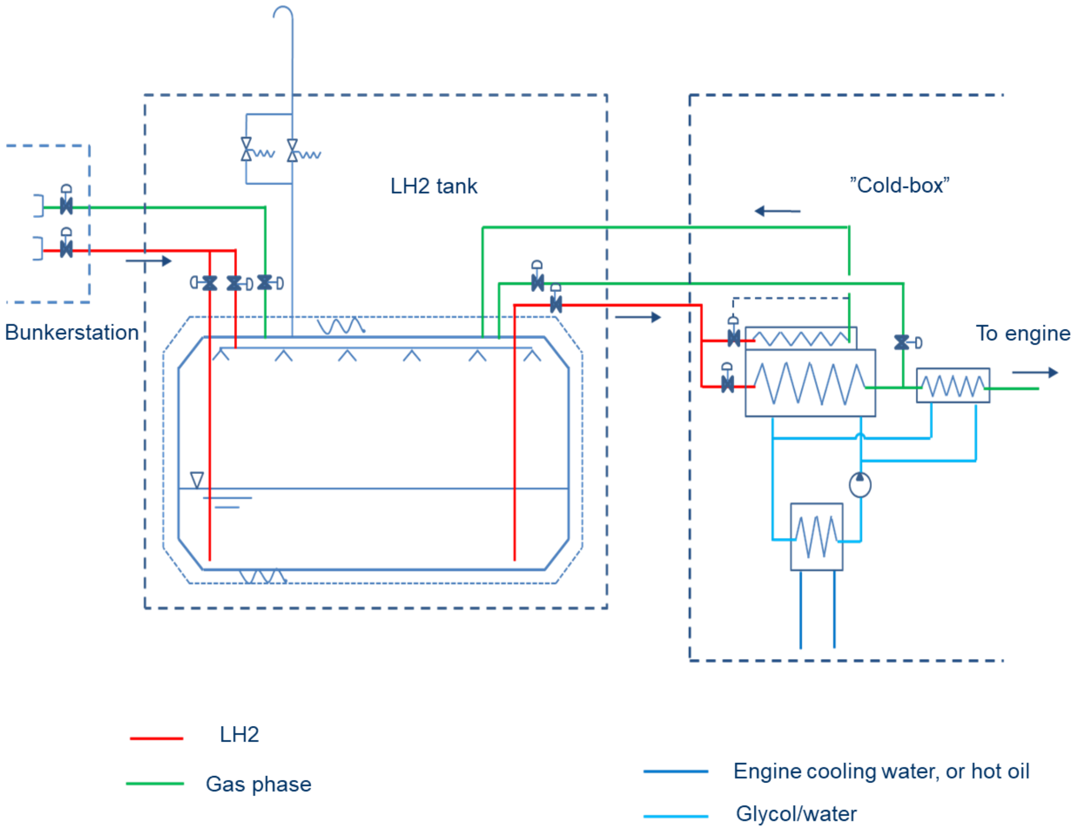



**Figure 6.5 – Princip diagram of LH2 storage system on board based on industry standard for cryo-fluid handling.**

A dedicated bunkering station need to be implemented on the ship side on starboard or port side depending on ship orientation in harbour. In dedicated ship routes it will be possible to decide details on practical ship design on this issue. The bunkering station on board will be defined as a separate safety zone and restrict the use of nearby area on the ship.

The bunkering station consist of pipe connections points and valve arrangement for LH2, vent and purging system, communication system, gas alarm and safety systems.

Bunkering system for LH2 will in principle be equal to similar systems for LNG, including LH2 storage, cryogenic pump, distribution system, boiloff handling system and inert gas system. Such land-based installations are not further discussed in this report. LH2 could also be bunkered from trailers similar to LNG bunkering. A third option may be bunkering from a LH2 bunker boat, but such system also needs to be developed.

A critical issue for cryogenic refueling is the time required for safe and efficient bunkering operation. This includes system purging before and after filling and cooldown of all piping to minimize evaporation, boil-off handling and connection to the ship. Estimated time required for preparation of LH2 bunkering from a trailer are one hour (ref. Air Products, Powercell webinar January 2022), but none such systems exist, so experience is limited. In addition, the bunkering time itself need to be included which are based on pump capacity for the specific LH2 bunkering system.

A likely first step to utilize LH2 on ships is to use existing technology with bunkering from trailers. Pump capacity from trailers operated by Air Products is 1500 kg/h, but systems with larger capacity may be required to minimize bunkering time. Existing trailers have storage capacity from 2900-3500 kg of LH2 and simultaneous bunkering from two trailers may be an option. In any case available bunkering time including bunkering preparation exceeds todays ship schedule where time in harbor is 1-1,5 hours, meaning that further development and adaption of a feasible bunkering system and procedure will be required. Technology exists from several suppliers for high capacity system, but time for cooldown and safety procedures is still required and should be minimized.

Another issue is safety concern and available space in harbor for bunkering operation. Bunkering from trailers will require safety zones and restriction in other activities on quay. In case of a realization project the bunkering issues need to be solved, which will involve industry partners and relevant authorities to develop a safe and feasible bunkering solution.

One important question which need to be clarified is if bunkering will be allowed while pax and roro operations are occurring. Such operations are allowed for LNG fuelled ROPAX ships, and parallel bunkering and loading operation is required to meet the operational profile of the ship.

## 6.2 Ammonia and methanol as fuel

Ammonia could be an option to reduce GHG emissions from ships. Energy storage design basis is 10 tons or 333 MWh tank capacity for H2. Energy equivalent amount of NH3 is 64 tons and app. 99 m3 storage volume. NH3 storage would typically be in pressure tank < 20 bar at ambient temperature.

Methanol is an alternative fuel and green methanol could be an option to reduce GHG emissions from ships. Energy storage design basis is 10 tons or 333 MWh tank capacity for H2. Energy equivalent amount of methanol is 60 tons and app. 77 m3 storage volume. Methanol storage would typically be in atmospheric tanks at ambient temperature.

The energy density per volume for ammonia and methanol is significantly higher than for hydrogen and fuel capacity could be increased for these fuels to meet operational requirements. This means that ship endurance could be significantly longer than when comparing to the hydrogen case without major reduction in load capacity. It would also mean that bunkering could be scheduled to meet operational requirement from the ship owner. No further details on these issues are evaluated in this report.

# 7 Power trains

## 7.1 Fuel choice and energy converter

Typical power train for ROPAX vessels today can have alternative designs and specification. The energy converter is dependant of the fuel choice as illustrated in Figure 7.1, and ICE or fuel cells are the alternatives for the fuels in concern in this report. In addition, hybrid system is an alternative combining mechanical and electrical energy for propulsion, or alternatively having backup fuels to increase flexibility and endurance of the ship in concern.

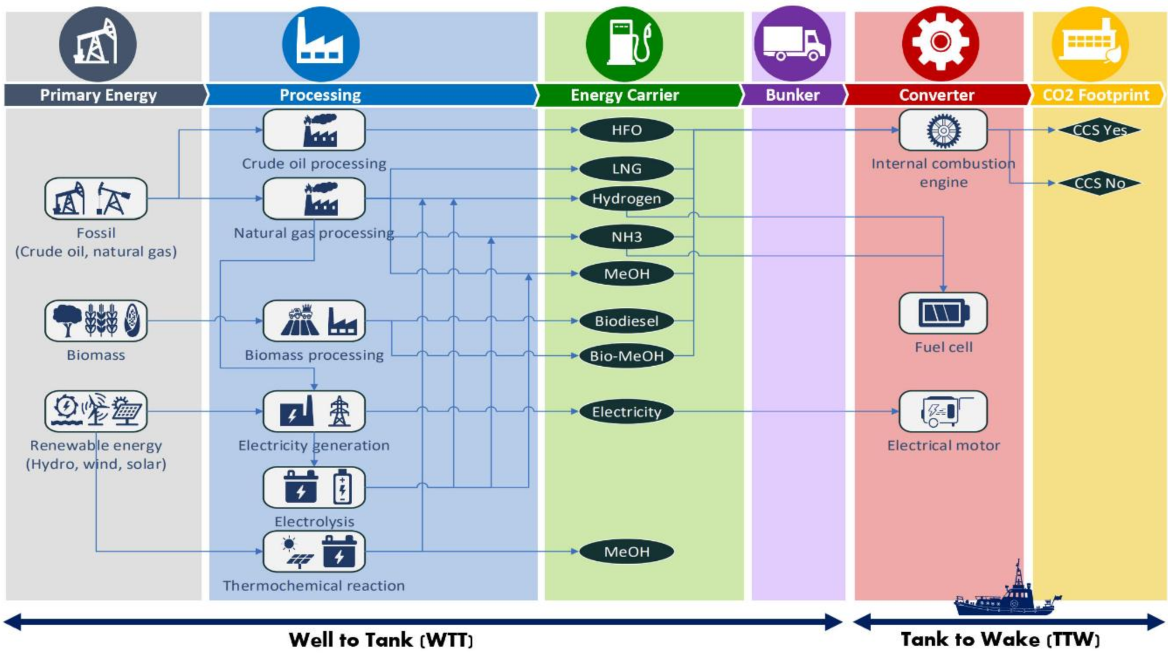



**Figure 7.1 -** Alternative energy converters dependant on fuel choice: ICE, Fuel cell or electric motor, /20/ .

ICE can in principle burn any fuels shown in Figure 7.1. Various engine technology is available, and the various fuels can be burned in diesel or otto engines and can be used in liquid or gaseous form. Maturity of engine technology vary for the alternative fuels in concern. ICE's for HFO, MGO and LNG is well proven and supplied by many manufacturers. The basis engine principle used of natural gas seems to be the best starting point for other alternative fuels as H2 or ammonia. All gas engines in operation today are derived from their diesel counterpart, which still is the dominating energy converter in ship today.

The diesel engines can also run on various types of biodiesel even though engine manufacturer are a bit reluctant to recommend such fuel due to lack of long-time operational experience and potential operational problems related to compatibility between fuel qualities. HVO renewable biodiesel is regarded as a drop-in fuel meaning that it could be used directly and is fully compatible with MGO. But guarantee issues may still occur from engine manufacturer when switching to such fuel.

Methanol and ammonia are promising alternative fuel which could be used in ICE. Methanol powered ICE are on the market and have been in operation in ships since 2015 in some demonstration projects. However, limited experience exists for this fuel, and only a few engines manufacturer can offer such technology at the moment. Further development of this concept will be market driven, and green methanol is assumed to be important in a future carbon free shipping trade.

Ammonia power ICE for ships are not available in the market yet, but several engine manufacturer are developing such engines. Ammonia has bad combustion properties as high auto-ignition temperature (651°C), low flame speed, narrow flammability limits (15-28% by volume in air) and high heat of vaporization /30/ and will be challenging to operate with high efficiency.

PEM FC can be used with ammonia as fuel but will need an ammonia processing system (ammonia cracker) to convert ammonia to H2 in advance of entering the fuel cell. Ammonia can also be used in SOFC directly, without fuel pre-treatment but such systems are still under development and not regarded as mature technology and SOFC for marine application is not available today. SOFC has some disadvantages to ICE and PEMFC with long startup-time and slow transient response which need to be considered in a propulsion plan arrangement to meet ship operational requirements.

Hydrogen can be burned in ICEs, but the properties of hydrogen also make it challenging to use directly as fuel in ICEs. Several manufacturers have demonstrated the concept where H2 has been blended with natural gas, and such application performs well. Operation on 100% H2 has been demonstrated and required major adaption of engine components and control system to ensure stable combustion and safe operation.

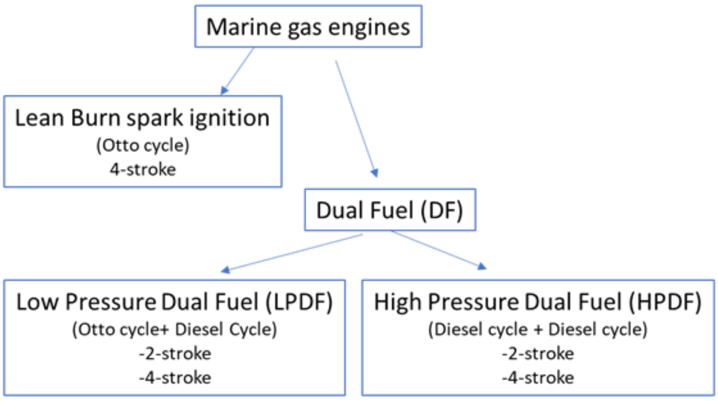
Alternative FC technologies are available and H2 PEMFC is the preferred solution and has been used for land base and automotive applications for many years and are now entering the maritime market. PEMFC can convert hydrogen directly but require high grade hydrogen to avoid any pollution and degradation of the FC and to extend lifetime. PEMFC can in principle use ammonia as fuel, but in such case a fuel pre-treatment system (cracker) is required and a purification system to clean H2 to required grade.

## 7.2 Internal combustion engines, (ICE)

### 7.2.1 Gas engine concepts

The alternative gas engine concepts are especially relevant for using hydrogen as fuel and are briefly described below. There are five different gas engine concepts as shown below within three main gas engine groups. These engines come in various versions dependent on fuel choice and are developed to burn natural gas and other alternative fuel types. Hydrogen and ammonia can be used as fuel in all these concepts which have different combustion characteristics that give different effects on efficiency and exhaust emissions. This means that the overall environmental effects by using alternative fuels are dependent on technology choice, something that is not arising in the general environmental considerations around alternative fuel operations of ships.

- Lean-Burn Spark Ignited engines (LBSI-engine),
  - Medium-high speed, 4-stroke cycle (0,5-8 MW)
- Low pressure Dual-Fuel engines (LPDF-engine),
  - Medium speed, 4-stroke (LPMSDF): 1-18 MW
  - Slow speed, 2-stroke (LPLSDF): 5-63 MW
- High-pressure Gas Injection (HPDF engine),
  - Medium speed, 4-stroke (HPMSDF): 2–18 MW
  - Slow speed, 2-stroke (HPLSDF): > 2,5 MW




As can be seen there are overlap in the power range between the concepts and choice of engine and gas system should be carefully evaluated in each case based on ship type requirements as propulsion power, redundancy, flexibility, endurance, operational profile, gas availability and commercial issues.

The LBSI and 4-stroke LPDF engines have been in operation in natural gas powered ships for some years and could be considered as proven technology. The LPDF 2-stroke engine (Winterthur Gas and Diesel, Win-GD) and the HPDF 2-stroke engine (MAN) have also been installed in commercial ships and is available in a large power range. The HPDF 4-stroke engine from Wärtsilä has been in operation for many years in the power plants on FPSO' s operating in the North Sea and for the onshore power plant market but has not been used for ship propulsion so far.

Today gas engines are offered from most suppliers in a wide power range, and these engines concepts form basis for using other alternative fuels.

### 7.2.2 Combustion principle

Combustion principles for the alternative gas engines concepts are illustrated in **Figure 7.2**, and these engine concepts are all candidates for hydrogen engines.

Lean burn spark ignited engines (LBSI) is a single fuel engine which operate on pure gas and use electric ignition system with spark plugs. The engine operates in accordance with the Otto-cycle, and gas is injected into the air flow and mixed with air during the intake stroke of the cylinder. The lean air/fuel mixture is compressed and ignited by a spark plug.

Low pressure Dual Fuel engine (LPDF) operates according to the Otto cycle as for the LBSI engine. This concept uses micro pilot diesel to ignite the lean air/fuel mixture.

For the LBSI and LPDF engine fuel can be premixed with air in advance of entering the cylinder in a gas mixer system. This results in a constant air/fuel ratio for all cylinders. Alternatively, fuel can be port injected which means that fuel is individual injected for each cylinder. Port injection require a more advanced control system.

High pressure dual fuel engines (HPDF) operate according to the Diesel cycle. Air is compressed as for ordinary diesel engines and at top of the compression stroke pilot diesel is injected for ignition purpose and simultaneously high-pressure gas is injected as the main fuel.

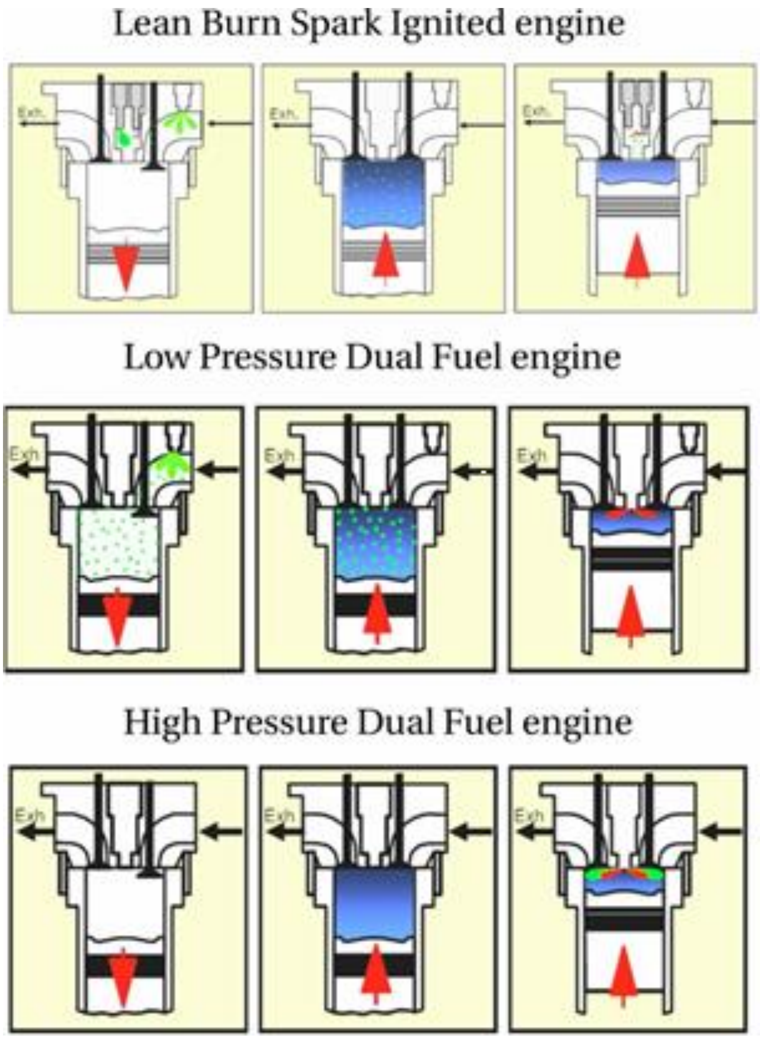



**Figure 7.2 – Gas engine concepts – combustion principle**

LBSI
1. Suction stroke – gas injected and mixed with air
2. Compression stroke: Gas/air mixture is compressed
3. Ignition by spark plug, (placed in pre-chamber for larger engines)

LPDF
1. Suction stroke – gas injected and mixed with air
2. Compression stroke: Gas/air mixture is compressed
3. Ignition by pilot fuel

HPDF
1. Suction stroke – air succeed into the cylinder
2. Compression stroke: Air is compressed
3. Ignition by pilot fuel -continues supply of gas at high pressure

The technology readiness level of hydrogen as a fuel in ICE for marine application is limited. Only one supplier (BeHydro) has so far announced H2-fuelled ICE for the maritime marked based in LBSI and DF design. Core gas fuelled engines can be used as basis, but several technological issues on single components and systems need to be solved for most suppliers before H2 engines are available to the shipping market in large scale.

### 7.2.3 Hydrogen as fuel in combustion engines

The properties of hydrogen make it challenging to use as fuel in otto-cycle combustion engines. The minimum ignition energy in air is very low (0,02 mJ) compared to natural gas (0,29 mJ) and consequently potential for preignition (i.e. uncontrolled ignition during combustion stroke) is expected to be challenging. Hydrogen itself has high auto ignition temperature (585 C) and is therefore hard to ignite due to compression temperature alone. However due to the low ignition temperature, preignition due to hot-spots in the combustion chamber may develop into knocking, which again can result in major engine damage. An advanced fuel- and engine control system is required to detect any tendency to misfiring and secure safe operation within design limits of the engine. Basic engine parameters as the compression ratio need to be adapted to the fuel in concern to secure safe ignition and combustion. Engine design needs to ensure that there are no hotspots that can pre-ignite the hydrogen.

Hydrogen is expected to operate with very lean combustion. Compared to natural gas operation it is expected a significant decrease in power produced per unit of cylinder volume, meaning that the max power output of the H2 engine compared to natural gas counterpart will be lower. Such load decrease needs to be compensated by adding more cylinders, larger cylinders or more engines to meet a defined power requirements from a ship. Engine performance will be a compromise of NOx emissions, charging strategy, ignition and injection strategy, combustion chamber design, fuel efficiency, knocking control and more,/31/ , /35/ .

The hydrogen supply system needs to be carefully designed to avoid any leakage and keep a high safety standard. This involves material quality on sealings, piping and valves, injectors etc. Special focus is on hydrogen embrittlement and material quality need to be selected to avoid such problems. Material quality related to operational issues due to low lubricity as hydrogen is very dry is another issue which need attention. This may also influence on wear and tear of moving parts and lifetime of active components. Other operational issues would be inerting of inlet and exhaust system prior to start and after engine stop to avoid any traces of unburned fuel in the engine systems. In Cimac Guidelines /33/ important issues related to H2 as fuel in ICE is also addressed.

High Pressure Dual Fuel (HPDF) gas engines are diesel cycle concepts. Pure air is compressed, and a pilot oil injection secure ignition and a gas jet is injected at top dead centre in similar pattern as diesel sprays. This concept could be used with hydrogen as fuel, and there are some advantages in gas operation for this concept:

- Diffusion combustion of H2 meaning that hydrogen is injected at high pressure close to top dead centre after the intake valves are closed.
- Safe ignition as pilot oil is used for compression ignition
- Knocking issue is eliminated due to compression of air only.
- No requirement for hydrogen quality, low-grad H2 can be used directly

HPDF gas engines have the same characteristics as the diesel engine regarding power range, fuel consumption and load pick up. The disadvantage is the requirement for high gas pressure supply of gas in the range of 350 bar for natural gas and it is assumed that similar pressure level will be valid also for hydrogen but that needs to be confirmed in a development process. Hydrogen injection need to be properly mixed with air in the cylinder and combustion chamber modification may be required. Natural gas fuelled ships use LNG storage on board, and a high pressure cryogenic pump to obtained required pressure. Similar system is assumed to be required also for hydrogen powered ships using HPDF technology for energy conversion, and such systems for marine application need to be developed. Cryogenic high pressure pumps, in this case piston pump, is existing mature technology. However, they are not developed for this kind of application with continuously operation. One experience and challenge with LNG pumps is too short time between overhaul which increase maintenance cost. This may also be a challenge to LH2 pumps. Another option to achieve high pressure hydrogen to a HPDF engine could be based on compressed H2 storage systems at 350 bar. To utilize the storage volume on board, such system will probably need high pressure compressors, accumulators and other relevant auxiliary systems. Alternatively, the storage pressure could be increased to e.g. 750 bar. In addition, a gas handling and pressure control system would be required. Marine installations at such pressure may need further development and approval before it can be used on board a ship.

### 7.2.4 Conventional power trains

Power train for ROPAX ships today can be conventional power trains with mechanical drive of propeller through traditional shafts, diesel electric power train with electric driven propeller or hybrid arrangement with electric or mechanical driven propeller. There are a lot of combinations, and the final design choice is often decided by operational profile and ship owner requirements. Example of power train design of a hybrid DC machinery system from Wetech is shown in Figure 7.3.

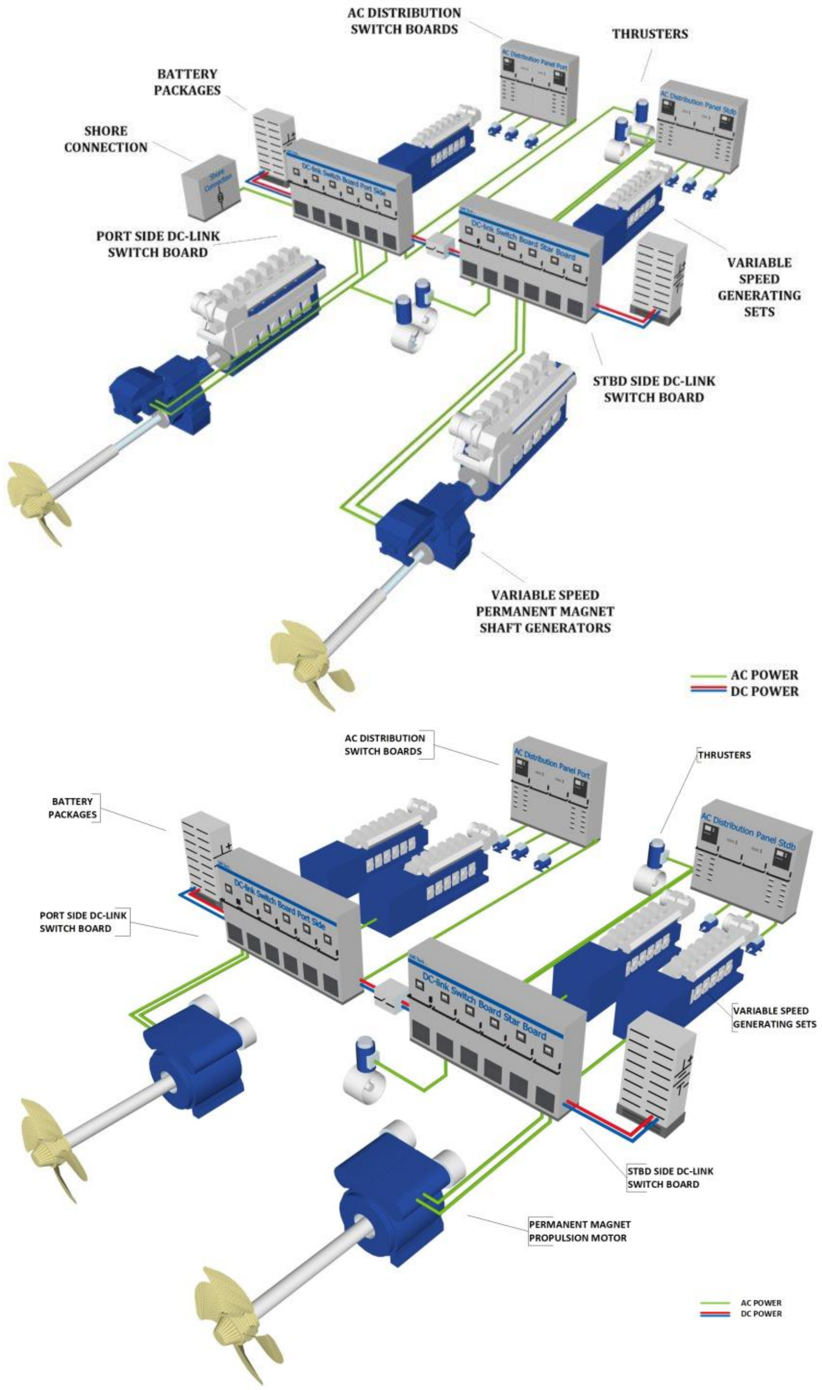



**Figure 7.3 – Power train arrangement, hybrid DC machinery examples from Wetech, [http://wetech.fi/solutions/solution-five/](http://wetech.fi/solutions/solution-five/)**

The alternatives shown in Figure 7.3 shows one alternative with main engines connected to gear box and a variable speed shaft generator and mechanical shaft to propeller from gearbox. Electric power can be generated from auxiliary gen-sets or from main engine via shaft generator. Electric power systems consist of a DC link with a battery connection. AC power is supplied to main consumers as thrusters etc. The other alternative shows a diesel electric power distribution system. Main gensets produce AC-power to main switchboard, which include a DC link for battery connection. Propellers are electrically driven from PM propulsion motors.

Propulsion power plant for the case ship require 16-17 MW to obtain design speed of 21 knots giving significant power and speed reserves and bad weather operation capability. A twin screw propulsion system give redundancy and the powerpack could be design as indicated in Figure 7.3.

### 7.2.5 Hydrogen engine availability

Internal combustion engines running on pure hydrogen is not available in the required power class. Behydro has launched two versions of a hydrogen fuelled ICE, one DF and one pure H2 with spark ignition. The dual fuel engine is design to operate with 75% hydrogen and 25 % diesel fuel, and the LBSI engine will operate with 100% H2 as fuel. This engine is available with 6, 8, 12 or 16 cylinders and delivers a power from 1000 to 2670 kW. According to Behydro the DF engine has an efficiency of 40%. The engine has not been tested in ship application.

The engine will reduce CO2 emissions proportional to the hydrogen consumption, that is in the range 75-100 % dependant on engine type. The engine may have emissions of NOx and PM (dual fuel) and may need an aftertreatment system to obtain low emissions according to IMO tier III regulations.

No other manufacturers have launched hydrogen engines, but main manufacturer has demonstrated concepts with H2 blended into natural gas. Hence, the overall TRL level for H2 fuelled engine is 5-7 depending of manufacturer. Existing natural gas engine technology can be used for 25-30% H2 blends as such fuel would follow the combustion characteristics of natural gas but 100% H2 fuel-engine will require significant development and testing.

The Behydro engines are operating as gen-sets producing electric power to a switchboard. Assuming that the engine system is made inherently safe, most of the standard component can be kept, and a ship conversion would mainly consist of changing engine and fuel system, including all relevant safety and control systems. A machinery system with hydrogen as fuel would in principle be equal to a natural gas powered propulsion system.

### 7.2.6 Emission characteristics of H2 ICE

Utilizing H2 as fuel will have significant influence of the emissions from the engine. Initial comparison reference is based on emissions running on MGO. A switch to natural gas will reduce regulated emissions as NOx and SOx and also reduction of GHG, but as we know not to the extent which can be achieved with H2 operation.

Emission reduction from marine gas engines relative to a conventional engine operated with diesel fuel in IMO E2/E3 test modes without exhaust gas aftertreatment is shown in **Figure 7.4**. In DF engines, marine diesel oil was used for pilot injections.

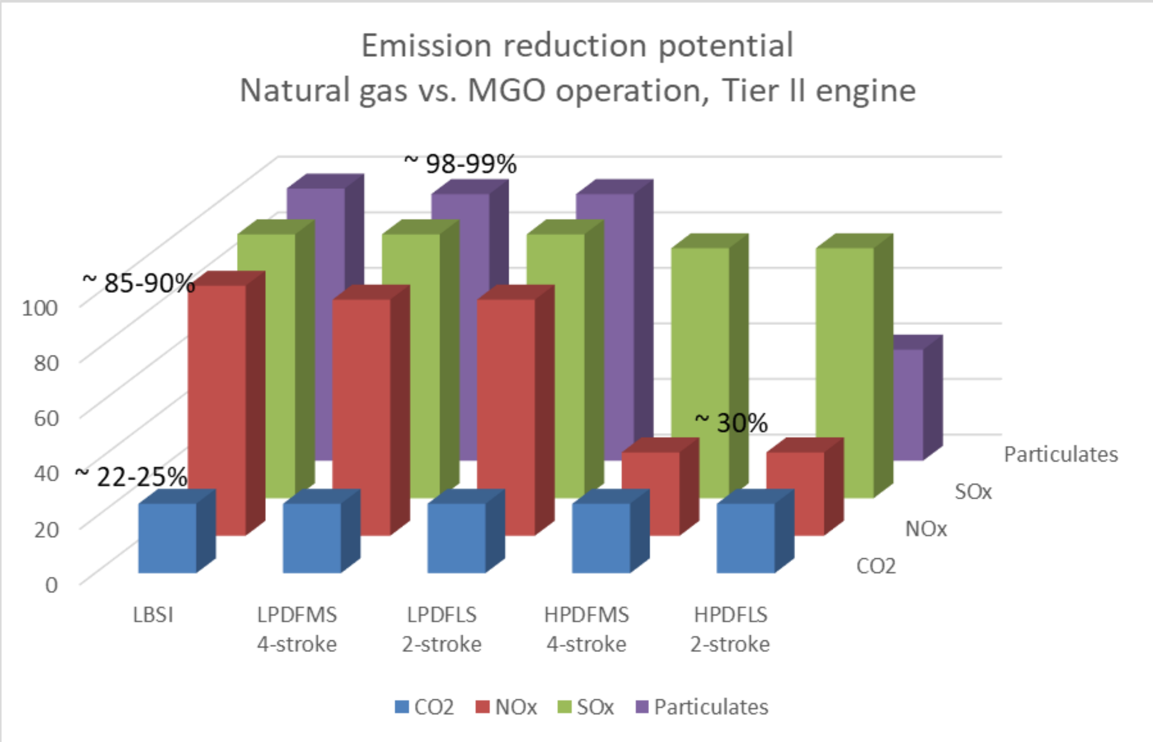



**Figure 7.4 – Emission reduction potential, gas engines concept compared to MGO operation, various sources. (PM reduction for HPDFSL is compared to HFO operation, MAN data)**

For all gas engine concepts, the following emission reduction potential apply when comparing natural gas operation to MGO operation and estimated increased reduction by using hydrogen as fuel:

- For natural gas operation CO2 is reduced by 22-25%. This is due to the lower carbon content of the fuel and that all concepts achieve high thermal efficiency its working cycle. H2 operation: 75-100% reduction of CO2 dependant of engine technology. (Pure H2 operation will give 100% reduction). Dual fuel operation will need pilot diesel fuel to ignite the H2/air mixture which will influence the CO2 emissions. Behydro informs that their DF concept operate with 25% pilot fuel.

- For natural gas operation NOx is reduced by 85-90% for low pressure engines due to lean combustion and lower peak temperatures in the combustion process. NOx tier III requirements are fulfilled without any additional cleaning. For high pressure engine a NOx reduction of app 30-40% can be expected. This means that the HP engine need a NOx reduction devise or technology to reduce these emissions to meet IMO Tier III requirements. For H2 operation it is assumed very lean operation to control combustion and knocking, which give potential to low NOx, in the range of gas engines or lower depending of the combustion process. Using HP engine technology is likely to create higher NOx which need to be handled in an aftertreatment system.

- SOx is significantly reduced by all engine concept due to low sulphur content in the natural gas. Pilot diesel my contribute to small SOx emissions for dual fuel engines. H2 operation will have same effects, and H2 is also sulphur free.

- For natural gas operation particles matter (PM) is reduced significantly. This is due to the fuel quality with low carbon content and low sulphur content in the fuel, as PM mass is dependent on the sulphur content in the fuel. For H2 operation even lower PM emission could be expected due to excess of carbon in the fuel, but dual fuel engine may suffer from PM generated from the pilot fuel.

- In a GHG perspective methane slip need to be considered for all gas engine concepts. Only the HPDF concept has the potential to obtain close to zero methane slip while the other gas engine always will suffer from some methane emissions, but this will vary between engine types and engine design and control strategies. In any case the methane slip needs to be accounted for in a GHG perspective. For H2 operation methane slip is not an issue. However, parts of unburned H2 may be an issue but this is not regarded as an environmental concern.

### 7.2.7 ICE thermal efficiency

The thermal efficiency characteristics of ICE shows an optimal point around 75-85% of maximum power (defined as maximum continuous rating- MCR). For large 4-stroke medium speed gas fueled engines the thermal efficiencies are 46-48% at MCR from different suppliers. For slow speed 2-stroke engines the thermal efficiency is about 50%. For an ICE the thermal efficiency will stay high during lifetime with normal maintenance, and there are no degradation or ageing of components from the combustion process which influence on the efficiency. Development target for H2 engine would be to match natural gas powered engines with respect to efficiency.

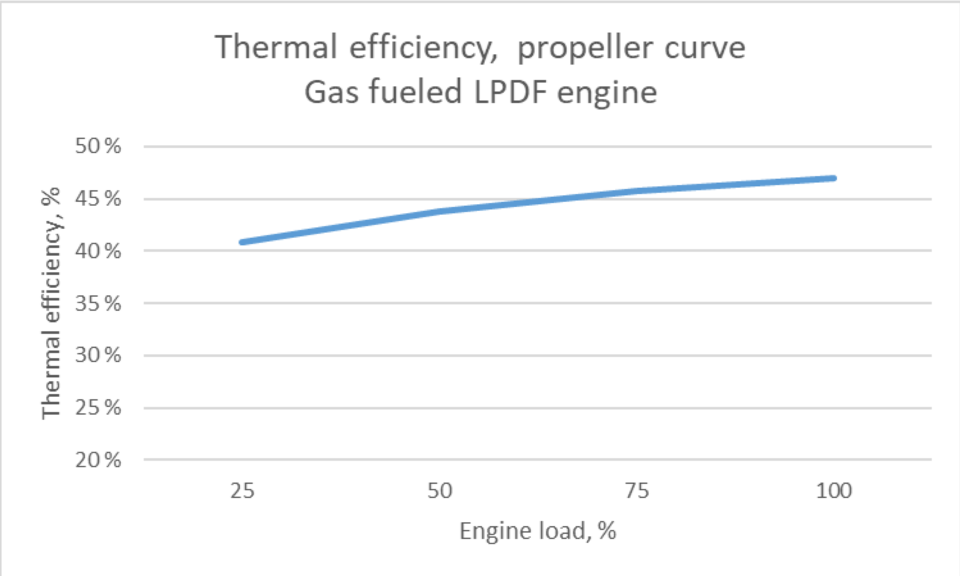



**Figure 7.5 – Typical thermal efficiency for gas fuelled LPDF engine, real operation, (ISO tolerance for fuel consumption included in curve).**

An example of energy balance for a state-of-the-art marine ICE is shown in Figure 7.6 based on simulation but using existing engine data and HFO as fuel. Shaft efficiency of 44% can be achieved and main losses are in cylinder cooling water and exhaust gasses.

Exhaust has high temperature and can be utilized in boilers, economizers, etc., which is common practice in ship systems today. Low temperature heat from cooling water may be utilized in various types of waste heat recovery systems from simple heat exchangers for central heating to more advanced waste heat recovery systems. Cooling water pumps are engine driven and charge air is supplied through the turbo chargers.

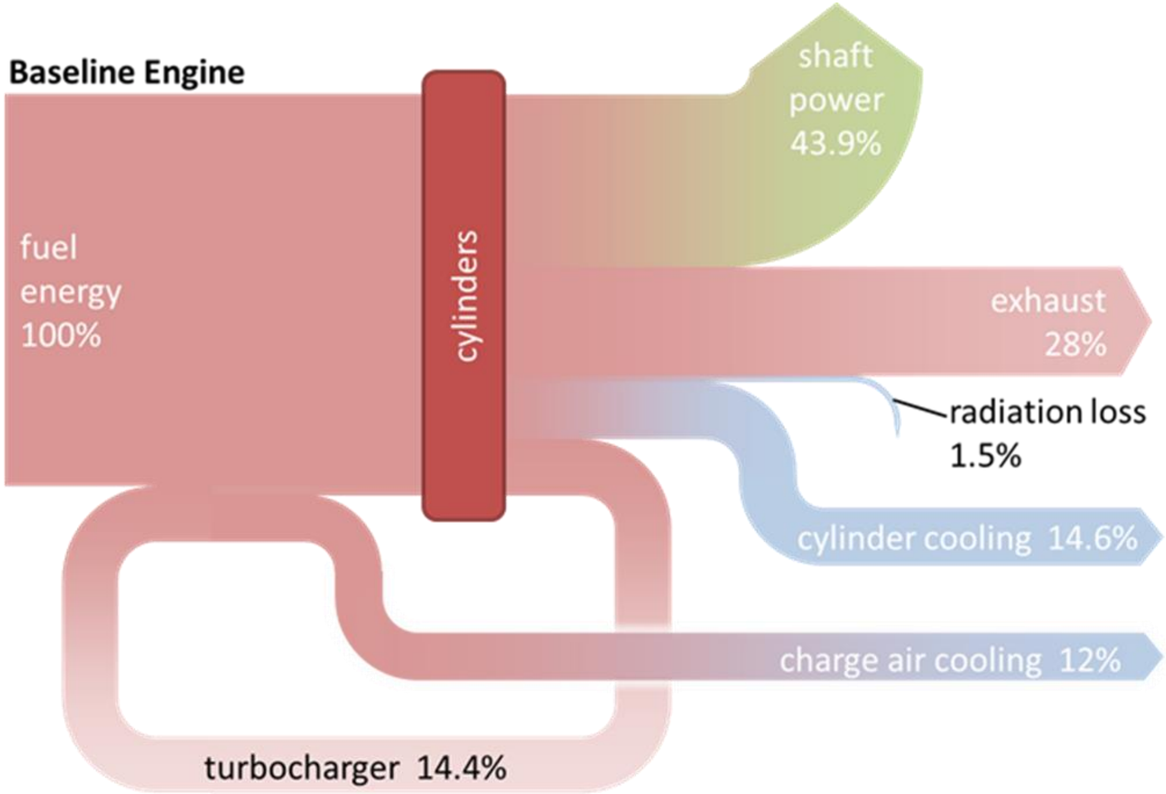



**Figure 7.6 – Sankey diagram of energy flow in diesel engine. Simulation results based on existing engine data and HFO as fuel, (Sintef Ocean).**

Several auxilliary systems are required for an ICE as fuel transfer and distribution systems, lube oil circulation and cooling system and cooling water system.

### 7.2.8 Cost issues for ICE for marine application

Investment cost of existing marine diesel fueled engines are in the range 300-500€/kW, and "rule of thumb" annual operational cost is 0,02 €/kWh produced., (ref Stena). For a hydrogen powered engine it could expected significant higher investment price due to development cost and new component and systems around the engine. Natural gas engines have additional production cost around 20-40% compared to their diesel engine counterpart depending on technology level and similar or higher additional cost will most likely apply to H2-powered ICE's.

## 7.3 Fuel cells

In a PEMFC the chemical energy in the fuel is converted to electricity by electrochemical reactions. Principle of a PEMFC is shown in Figure 7.7. Fuel enters on the anode side of the fuel cell and air enter the cathode side. H+ protons are led through the electrolyte (polymer membrane) and reacts with oxygen molecules in the air to form water as an end product. The PEMFC operate with efficiencies around 50% and at low temperature (70 °C). Low temperature cooling water is available from a fuel cell system. A fuel cell operates without vibrations and with low noise, but fuel cell auxiliaries as air supply systems and cooling water systems may change this picture.

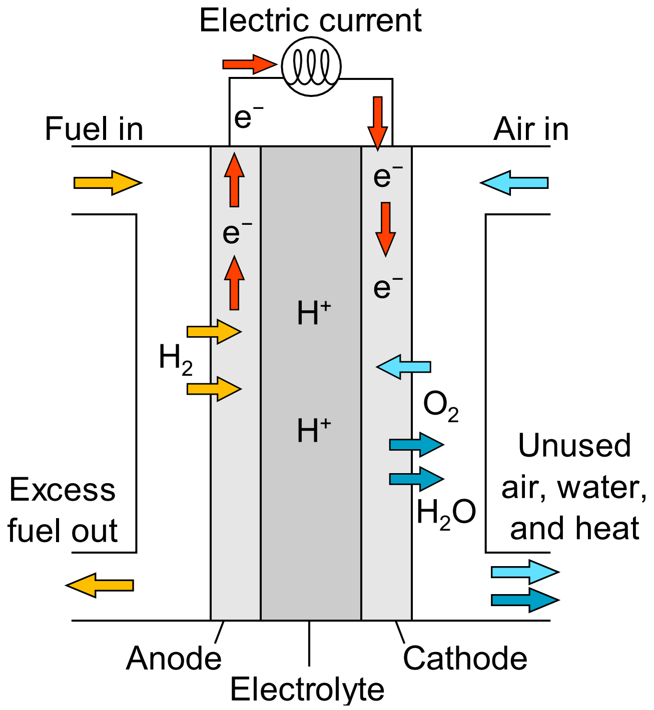



**Figure 7.7 - PEMFC operation principle, https://en.wikipedia.org/wiki/Proton-exchange_membrane_fuel_cell.**

PEMFC for marine application are offered by several suppliers as Powercell, Ballard, Cummins (=Hydrogenics) Nedstack and others. Fuel cell power systems consists of multiple modules with typical power of 200 kW for a single module and is scalable to MW range.

Powercell single module is rated to 200 kW and installed in racks as shown in Figure 7.8.


**Figure 7.8 - PEMFC rack of 200 kW from Powercell, https://powercellgroup.com/.**

The technical data specified in Table 7.1 apply to the 200 kW PEMFC from Powercell.

Table 7.1 – Specification of 200 kW PEMFC unit from Powercell, https://powercellgroup.com/

| PowerCellution Marine System 200 | |
|---|---|
| **Parameter** | **Properties** |
| Max net power, kW | 200 |
| Dimensions, m | 0.7 x 0.9 x 2.0 |
| Volume , liter | 1260 |
| Weight, kg | 700 |
| Gross Output (rated power) | 600V/380A |
| Voltage Output , Normal operation: | 500-1000 VDC |
| Current Output | 60-450 A |
| System heat Output | Up to 200 kW |
| Coolant outlet temperature | Up to 80 °C |
| Fuel Quality | Hydrogen ISO 14687:2019, SAEJ2719_201511 and T/CECA-G 0015 201 |
| Fuel Inlet pressure | 3-8 bar (g) |
| Fuel Consumption | 13 kg/h at 200 kW |
| Communication and control | Can Bus |
| System efficiency (peak, BOL) (BOL=Beginning of life) | 60 % |

A megawatt machinery system with PEMFC need multiple FC racks stacked into a system. Powercell has shown typical arrangement for MW installations. Such system has yet not been demonstrated and would have a TRL level of 7, /40/ .

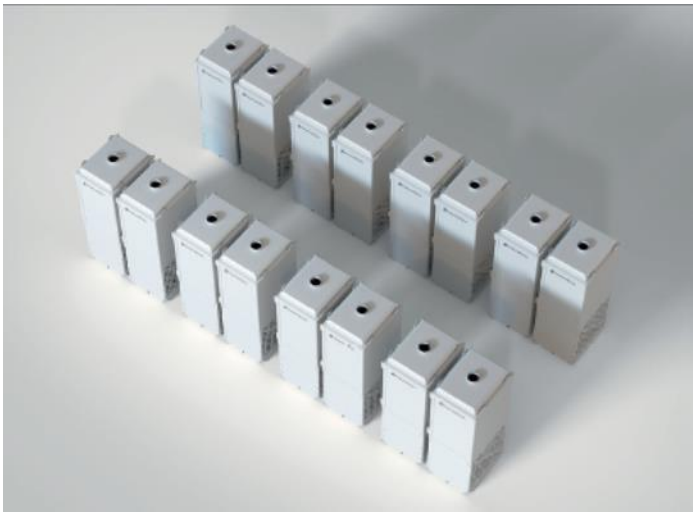


**Figure 7.9 - Concept design of 3,2 MW Fuel cell block, 16 single FC units arranged in pairs of two units, ref. Powercell**

For our ROPAX case ship design the installed power requirement from fuel cell is assumed to be 20 MW split in 100 single stacks of 200 kW each. This makes it possible to operate FC close to best efficiency in low load operation. At high loads the system efficiency will drop, and a clever energy management of the FC system is required to optimize fuel consumption and minimize degradation and overall cost. Because a fuel cell stack has the best efficiency at lower load the design and operational philosophy should consider a design approach which is beneficial to optimize capex and opex costs. Details must be determined with an overall cost-benefit analysis for the operational profile provided and is further studied in WP 4 of this project.

Each fuel cell stacks are connected to a DC/DC converter and further connected to a common DC link/switchboard from where power is distributed through power electronics to consumers on board. Detailed design of FC stacks and power system arrangement is required in each case to find an optimal system solution with respect to investment and operational cost. This must be determined with an overall cost-benefit analysis for the operational profile provided. Footprint and weight are estimated below.

**Table 7.2 – Footprint and weight, 20 MW fuel cell installation.**

| **Single stack dimensions:** | | Unit |
|---|---|---|
| Length | 0,7 | m |
| Breadth | 0,9 | m |
| Hight | 2 | m |
| Footprint | 0,63 | $m^2$ |
| Service space | 0,63 | $m^2$ |
| Total space in ship | 1,26 | $m^2$ |
| Weight per unit | 700 | kg |
| **Ship system 20 MW, 100 stacks:** | | |
| Footprint | 63 | $m^2$ |
| Service space | 63 | $m^2$ |
| Total space in ship | 126 | $m^2$ |
| System weight | 70000 | kg |

## 7.4 Fuel cell efficiency

FC efficiency curve for a 100 kW system is shown in Figure 7.10, and varies from 45% at rated power to 55% at best operation point at about 30% load. This is a characteristic efficiency profile for any PEMFC for a new system. (BOL=beginning of life). Expected degradation due to normal use will reduce the efficiency and at end of life it can be expected that efficiency at rated power has dropped 5-6% compared to a new system. Such effects need to be counted for in the design process.

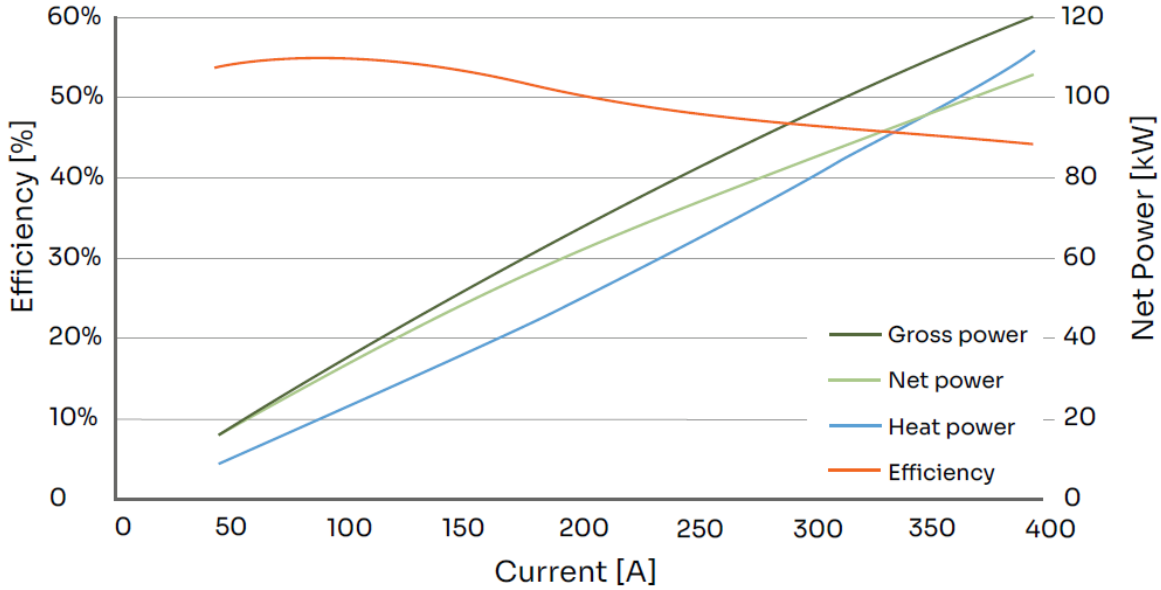


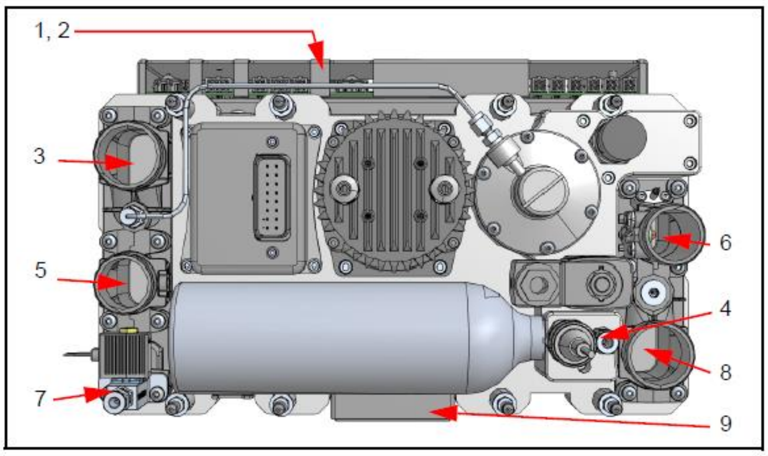

**Figure 7.10 - Performance measured at reference conditions and BOL, Ref. Powercell, Power Generation System 100.**

Expected life time of fuel cells are dependent on operational profile. Optimum lifetime can be achieved with steady-state operation. Expected lifetime from for Powercell MS100 system is 20000 hours and Ballard FC Wave indicate a lifetime of 30000 hours (ref. https://www.ballard.com/).

## 7.5 Fuel cell auxilliary system

### 7.5.1 System overview

Several support systems are required for a fuel cell system. Example of single PEMFC module auxiliary interface systems is shown in Figure 7.11. Connection points for fuel, process air, cooling water, exhaust and system purge are arranged.




1, 2: Electric input signals
3: Process air inlet
4: Hydrogen inlet
5: Coolant inlet
6: Coolant outlet
7: Hydrogen purge solenoid valve
8: Exhaust outlet
9: Main power (electric) output

**Figure 7.11 – Auxiliary system interface on single PEMFC module, Ref. Hydrogenics**

### 7.5.2 H2 fuel system

Hydrogen is supplied to the fuel cell in double piping and enters in the bottom part of the fuel cell stack, at low pressure, 3-10 bar dependent on manufacturer. Pipe connections is arranged at stack entrance. Hydrogen is supplied in gaseous form at low pressure. From H2 storage system a gas regulating unit is required to handle pressure and flow control, filtration, any temperature requirements to the fuel and fuel shutoff and purging and other relevant fuel function. The hydrogen supply system should be dimensioned to handle any pressure drop in the system and specified input pressure from manufacturer shall be maintained for all gas flows.

### 7.5.3 Cooling water system

A cooling water system is required, and special requirements apply to such system. Large amount of waste heat will be available, as the FC system operate with an efficiency of about 50%. Dimensioning of the cooling system need to consider fuel cell degradation and efficiency variation versus load profile. Lowest efficiency is obtained at design load (100% load) and degradation effects is also expected to be largest at this point. Reduction in efficiency imply increased heat losses which need to be handled by the cooling water system.

The fuel cell racks require a cooling water system with coolant outlet temperature of app. 70-80 °C. Cooling medium are de-ionized water which should be circulated in a closed loop system and cooled in a central cooler by fresh water or sea water. Alternatively, a glycol based cooling water could be used. Special quality of cooling water apply with typical resistivity of 0,2-2 MΩcm. Deionizing filters may be required in the cooling water system. Normally the cooling water system is a part of the FC stack as a separate module which also include input air systems, and in such cases external cooling system need to be arranged on the ship.

For our case ship with a fuel cell efficiency of 50%, at least 20 MW waste heat is expected and most heat is released through the cooling water system and only a minor part through exhaust gas. The cooling water system is required for continuous operation, and flow control may be based on temperature regulations depending on fuel cell load.

A waste heat recovery system should be included to utilize waste heat for heating and other purposes on board. Efficient utilization of low temperature thermal heat may be a challenge and should be carefully considered in the design phase. Cooling is also required for power electronics, (drives, inverters, etc.).

For a large 20MW FC system with 100 single FC units with individual controls, the cooling water system may be quite complex.

### 7.5.4 Process air

Process air system is required to supply air for the fuel cell. Special requirements apply to the air quality related for use in the process. Process air should be supplied through a separate process air system and blowers/air compressors is required to supply required quantities. Such blower may be included in the FC stack auxiliary module and be an integrated part of the FC stack. In addition, air cooler and air humidifier may be included. High purity air is required and chemical or mechanical filtration or a combination is required to secure that clean air supplied to the fuel cell. The particulate portion of the filter must protect the air delivery system from becoming clogged with particles. The chemical portion of the filter must provide protection of the fuel cell stack from contaminants such as sulfur, phosphates, organic compounds and trace metals. In maritime application any salt particles are of concern and cleaning system should be carefully designed to avoid any salt in the process air.

### 7.5.5 Vent air

A vent air system is required and is a part of the safety precaution of a FC stack. Any leakage escaping from the stack will be vented to safe area through this vent-system.

As a safety precaution a continuous flow of vent air is normally designed to flow through the fuel cell cabinet, entering in the bottom and dispatched in top. This system will vent any H2 leakage inside the cabinet to safe area, and the system is vital to avoid ex-requirements to the cabinet itself. Hydrogen detectors would be required in the vent air system.

### 7.5.6 Exhaust system

Exhaust system is required to handle large amount of water and water vapour. In the fuel cell hydrogen react with oxygen in the air and form water as end product. This will be discharged through the exhaust system together with excess air. Small amounts of excess hydrogen gas can be found in the exhaust gas, and this should be handled in a safe way. Exhaust pipe should be carefully designed to avoid any return or accumulation of condensed water from the exhaust and final exit should be in a safe area.

### 7.5.7 Hydrogen purge system

A hydrogen purge system is also required as excess fuel in the FC process normally is purged to a separate purge system. This system needs to be vented to safe area. Excess hydrogen will remain on the anode side of the fuel cell and this will be purged to the exhaust system. Separate purge lines could be arranged. According to Powercell H2 purge amounts to 0,5-1,5 % of H2 consumption. Hydrogen purge lines need to be routed to safe area.

### 7.5.8 Leak detection and safety system

Leak detection and safety system will be important in any systems in contact with hydrogen. This involves double piping for hydrogen transfer including leak detection and potential also inert gas in piping annular as indicated for the H2 storage system. Leak detection sensors are also required in the vent air system to detect any H2 leaks inside the cabinet.

### 7.5.9 Electric systems

Cables for main power output is connected to each stack and terminated to a local DC-DC converter. For a 200 kW unit the output power could vary from 450-1000 VDC and current from 45-450A. To achieve high power systems the FC stacks are connected in parallel to a common DC- link.

## 7.6 Cost issues for marine fuel cell system

Specific cost investment cost for a PEMFC today is about 1500 €/kW and is expected to decrease the next 5-10 years as technology becomes mor mature. The lifetime issue for fuel cells makes it necessary to plan for replacement of FC stack which has reach end of life and this will be a part of the service/operation cost of such systems. An estimated service price for PEMFC system is 0,044 €/kWh during a 15 year long project period (ref Powercell).

## 7.7 Hybrid systems

A fuel cell system can be integrated as a part of a hybrid power plant. SINTEF Ocean has demonstrated such arrangement in own laboratory in cooperation with ABB, where diesel gensets, batteries, fuel cells and super capacitors are integrated in a machinery setup. Electric power is produced by variable speed AC generators or from the fuel cells. Batteries are used to store access energy, as peak shaving or as main power source for the electric motors. All power sources are connected via power electronics in a DC link and distributed to a motor/brake setup for simulation of a marine propulsion system. A simplified single line diagram of the system is shown in Figure 7.12.

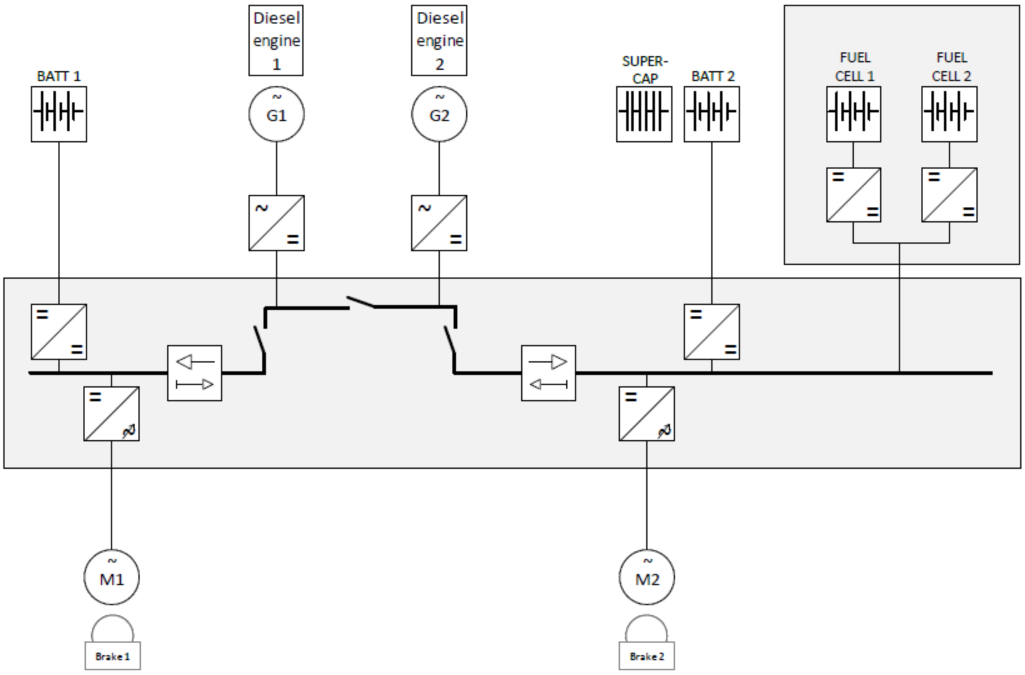



**Figure 7.12 - Hybrid machinery system arrangement in SINTEF Ocean laboratory.**

For a hybrid system a rather complex electric system integration is required. From each fuel cell DC power is produced and need to be connected to a local DC/DC converter and further supplied to a common DC-link where batteries and other power electronics is connected. The electric power system is in principle equal to industry standard used in diesel electric or hybrid ships today.

## 7.8 Battery system

It is a tendency to make hybrid machinery systems including battery package. This makes it possible to charge batteries during harbour stay and operate on electric power at low load requirements, i.e. in harbour or at berth or in special low emission zones. It also opens for peak shaving and fuel optimisation in cases this is relevant. Marine batteries have developed to be mature technology the last few years and are today offered by several suppliers.

One of the largest marine battery systems so far of 6,1 MWh was supplied to the coastal cruise ship "Havila Capella" operating along the cost of Norway.  This was a Corvus Orca Energy battery supplied by Corvus

Energy. Corvus Energy has several references to other ships with more than 5 MWh installed battery capacity. Battery packs for ships are modularized and can be built to supply energy in the MW range. Battery systems are approved by class and included in classification regulations from class societies.

For a fuel cell systems operational aspects related to transient operation can be solved by integrating batteries in the power system on board. A first estimate on battery size for the case ship is 2 MWh. Corvus energy is one supplier of batteries for ships and example of their product is shown in Figure 7.13


| Performance Specifications | |
|---|---|
| C-Rate - Peak (Discharge / Charge) | Project Specific Values |
| C-Rate - Continuous (Discharge / Charge) | Up to 3C / Up to 3C |
| **System Specifications** | |
| Single Module Size / Increments | 5,6 kWh / 50 VDC |
| Single Pack Range | 38-136 kWh / 350-1200 VDC |
| Max Gravimetric Density - **Pack** | 77 Wh/kg \| 13 kg/kWh |
| Max Volumetric Density - **Pack** | 88 Wh/l |
| **Example Packs** | |
| Energy | 124 kWh (249 kWh for Tall Pack) |
| Voltage | Max: 1100 VDC \| Nom: 980 VDC \| Min: 800 VDC |
| Dimensions - Vertical Pack - 124 kWh | Height: 2241 mm \| Width: 865 mm \| Depth: 738 mm \| 1628 kg |
| Dimensions - Horizontal Pack - 124 kWh | Height: 1260 mm \| Width: 1730 mm \| Depth: 738 mm \| 1726 kg |
| Dimensions - Tall Pack - 249 kWh | Height: 3000 mm \| Width: 1345 mm \| Depth: 738 mm \| 3375 kg |

**Figure 7.13 – Corvus Orca Energy battery pack, 124 kWh, https://corvusenergy.com/**

The case ship operating in normal route would have six stops a day (three return trips) and dimensioning time in harbour will be one hour. Power consumption in harbour is estimated to 1 MW which could be supplied by FC or batteries or in combinations, whichever is most feasible. The following battery pack would be required for the case ship:

- Assumed installation: 2 MWh
- Technical specification, batteries from Corvus, eight "tall packs":
  - Total weight: 27 tons
  - Footprint each pack: LxBxH: 1,4x0,8x3 (m3)
  - Footprint, eight packs: 9 $m^2$, (+ service space)

Special requirements for battery rooms on board applies in classification rules, and several auxiliary systems is required:

- Battery management system
- Cooling system
- Ventilation system
- Separate battery room
- Fire prevention system

# 8 Rules and regulations

Rules and regulations for maritime use of fuel cells are still lacking and the alternative design approach should be applied. This means that each project will be analysed in detail following risk based methods involving suppliers and experts to document high and acceptable safety standard for each case.

Safety issues for ships using alternative fuels are addressed in IMO IGF code. For fuel cell installations interim guidelines has been developed and safety issues is focused in the MarHySafe project which has issued a handbook for hydrogen fuelled vessels /39/ . Classification societies has developed rules and regulations for fuel cell installations and made type approval and approval in principle of various kind of fuel cell systems and relevant fuel systems and components.

## 8.1 IMO interim guidelines for the safety of ships using fuel cell power installations

Interim guidelines for the safety of ships using fuel cell power installations (MSC.1/Circ 1647) was approved by IMO in June 2022, /36/ . The goal of these Interim Guidelines is "to provide criteria for the arrangement and installation of fuel cell power installations with at least the same level of safety and reliability as new and comparable conventional oil-fuelled main and auxiliary machinery installations, regardless of the specific fuel cell type and fuel". The Interime Guideline is closely linked to the IGF Code , and the following functional requirements apply:

1. The safety, reliability and dependability of the systems should be equivalent to that achieved with new and comparable conventional oil-fuelled main and auxiliary machinery installations, regardless of the specific fuel cell type and fuel.

2. The probability and consequences of fuel-related hazards should be limited to a minimum through arrangement and system design, such as ventilation, detection, and safety actions. In the event of gas leakage or failure of the risk reducing measures, necessary safety actions should be initiated.

3. The design philosophy should ensure that risk reducing measures and safety actions for the fuel cell power installation do not lead to an unacceptable loss of power.

4. Hazardous areas should be restricted, as far as practicable, to minimize the potential risks that might affect the safety of the ship, persons on board and equipment.

5. Equipment installed in hazardous areas should be minimized to that required for operational purposes and should be suitably and appropriately certified.

6. Fuel cell spaces should be configured to prevent any unintended accumulation of explosive, flammable or toxic gas concentrations.

7. System components should be protected against external damages.

8. Sources of ignition in hazardous areas should be minimized to reduce the probability of explosions.

9. Piping systems and overpressure relief arrangements that are of suitable design, construction and installation for their intended application should be provided.

10. Machinery, systems, and components should be designed, constructed, installed, operated, maintained, and protected to ensure safe and reliable operation.

11. Fuel cell spaces should be arranged and located such that a fire or explosion in either will not lead to an unacceptable loss of power or render equipment in other compartments inoperable.

12. Suitable control, alarm, monitoring, and shutdown systems should be provided to ensure safe and reliable operation.

13. Fixed leakage detection suitable for all spaces and areas concerned should be arranged.

14. Fire detection, protection and extinction measures appropriate to the hazards concerned should be provided.

15. Commissioning, trials and maintenance of fuel systems and gas utilization machinery should satisfy the goal in terms of safety, availability, and reliability.

16. The technical documentation should permit an assessment of the compliance of the system and its components with the applicable rules, guidelines, design standards used, and the principles related to safety, availability, maintainability, and reliability.

17. A single failure in a technical system or component should not lead to an unsafe or unreliable situation.

18. Safe access should be provided for operation, inspection, and maintenance.

The functional requirement shown above stated in the Fuel cell Guidelines are nearly equal to IGF code and should be known by industry which has worked with gas fuelled ships. Some specific changes and variations with respect to fuel cell has been added and need to be considered. It is required that all functional requirements is documented by project owner to show compliance with regulations and this may be done by risk assessment as required in the IGF code section 4.2.

Design principles in the guideline give requirements and important advice on how implement a fuel cell in a ship system and give also design alternatives to obtain such safety. Important sub-section describes following issues:

- Fuel cell spaces
- Arrangement and access
- Atmospheric control of fuel cell spaces
- Materials
- Piping arrangement of fuel cell power system
- Exhaust gas and exhaust air

The Fire Safety section give general design requirement to obtain high safety standard and detailed fire mitigation strategies.

Area hazard classification zones are defined in the interim guidelines but should also be in accordance with IEC 60079-10-1:2020. In hazardous zones special requirements to electric equipment apply.

Control monitoring and safety systems is crucial and focus on safety related parts of the fuel cell control system, gas and vapour detection, ventilation performance, sensor placement, manual shutdown, alarm actions and safety actions.

The guidelines are a starting point for safe design and should be included in the alternative design process for new ships with fuel cell installations.

## 8.2 IMO IGF Code

The IMO IGF Code - International Code of Safety for Ship Using Gases or Other Low-flashpoint Fuels /37/ was adopted in 2015 and is fully developed for natural gas as fuel (LNG and CNG) but not for other alternative fuels. For these alternatives the "Alternative Design process" should be followed, meaning a risk based design approach, and such design should be approved by relevant national Maritim Administration, (Flag State). /38/

## 8.3 Class societies and standards

Class societies has developed additional class notations for ships with fuel cells and other specific equipment. Today Classification societies has type approved FC systems and components and some examples are:

- Fuel cells – type approved, project under way
- LH2 tank systems – approval in principle, approved in specific project
- CH2 pressure vessel: Pressure vessels: Type approved. System: approval in principle and for specific project

Several standards apply for single components and systems which is required in hydrogen fuelled ships. (ISO, ASME, CGA, EN, NFPA, EU-directive).

The Handbook for hydrogen fueled vessels, MarHySafe JDP Phase 1 1st Edition (2021-06) give a good overview of existing regulations and is a good starting point to achieve relevant knowledge in the design and approval process of hydrogen powered ships utilizing fuel cell as energy converter.

# 9 Fuel production from a Nordic perspective

## 9.1 Introduction

This section presents a review of plans for production of renewable hydrogen ($H_2$) and ammonia ($NH_3$) in the Nordics from a shipping perspective. Planned future and current green or blue hydrogen and ammonia projects in the Nordic countries Sweden, Norway, Finland, Denmark, and Iceland have been mapped. The identified projects span over various sectors and applications and their current status range between operational facilities and pre-studies. The survey was compiled in 2021 and updated in 2022, and identified projects may have been canceled or changed, but information provided below should give a broad overview of relevant project to supply carbon neutral fuel as H2 and ammonia in the Nordic countries.

In total 112 projects have been identified, distributed between the five Nordic countries (see Appendix I for a full list of all projects). Looking at the total number of projects, most of the identified projects are based in Norway followed by an almost even distribution between Denmark, Finland, and Sweden. However, looking at the total production capacity of planned projects, the plans in Denmark are exceeding those of Norway, with Sweden closely behind. Fewer projects (and lower total production capacity) have been found in Iceland. However, it is possible that there are more hydrogen projects in Iceland (and Finland) that have not been identified in this mapping (for example if they are at an early stage and published only in Finnish or Icelandic).

The following subsections present findings for each Nordic country. An overview of the hydrogen projects is provided including production capacity, location, and project status. A selection of projects considered to be of particular interest for the shipping sector is presented in more detail.

In this overview, the production capacity of the different projects and initiatives have been converted to tonnes of hydrogen produced per day (tpd $H_2$) assuming a conversion efficiency of 65% for electrolysis and using lower heating value (LHV) of hydrogen. The capacity of ammonia projects has, to facilitate comparison, been expressed as their capacity to produce hydrogen, although it is planned to be further converted into ammonia.

The mapping was primarily carried out between June 2021 and August 2021 with an additional update of projects in late 2022. Thus, further updates of the investigated projects published after that are consequently not included in this report. With that said, things are happening at a fast pace within the area of hydrogen and extending the search period would likely result in more projects and plans identified. An exception to the search window was also made for one project (Green Wolverine in northern Sweden), which was made public in October, but where the scale of the project motivates an exception and its inclusion in this mapping. The mapping only includes projects dedicated to produce principally pure hydrogen (with possible conversion to e.g., ammonia), i.e., excluding projects where, for instance, water and carbon dioxide ($CO_2$) is co-electrolyzed into syngas (e.g., the initiative by Norsk e-fuel 2020).

Since the mapping was carried out to assess the potential of hydrogen and ammonia as maritime fuels, proximity to possible bunkering locations or if maritime applications are mentioned have also been identified for the included projects. This is shown in the below tables using color coding, where projects located close (<20 km) to the sea or rivers have been marked with a light blue color and projects in which involved actors mention shipping as an application have been marked with a darker blue color. Following a similar logic, projects where the main capacity is dedicated for other purposes (e.g., fossil free steelmaking) have also been marked (with italic text), since these hydrogen/ammonia sources are judged less likely to be available for maritime applications.

## 9.2 Sweden

In Sweden there are several initiatives regarding green hydrogen production though most of the projects primarily have a focus on industrial applications such as the production of steel and methanol. A total of 23 projects related to hydrogen and ammonia have been mapped. The identified projects in Sweden have a combined total capacity of approximately 2,7 ktonnes of produced electro fuel per day, within 2030, of which the significant majority constitutes of hydrogen. However, many of the projects are at an early stage and the production's proximity to ports or possible bunkering locations for maritime applications suggests potential to expand the purpose of production to encompass more sectors. Most of the identified projects in Sweden are in the vicinity of ports or the sea, but only one project specifically mentions maritime application. Table 1 presents the identified projects in Sweden. For more details about the projects see Table A1 in the appendix. The projects presented in the text below is a selection of the identified ventures of particular interest for this review based on criteria such as application, production scale and future potential.

Steel production is very emission-intensive, and the steel industry is the largest emitter $CO_2$ in Sweden. H2 Green Steel is aiming to create the world's first large-scale fossil free steel plant. The fuel in the reduction reactors will be exchanged from natural gas to green hydrogen which will reduce the number of products from the reaction, only allowing sponge iron and water to be produced. The production facility will be in Boden, Norrbotten, due to the possibility of good access to fossil-free electricity. By using energy from renewable sources, in this case water and wind, hydrogen can be produced without any $CO_2$ emissions. The producing capacity of the plant is expected to 365 tons of hydrogen per day in year 2024 with hopes of doubling that before 2030 (H2 Green Steel, 2021). Although the primary purpose of this venture is to provide green hydrogen to the steel industry, it is not ruled out that potential excess hydrogen can be used for other applications such as fuel for maritime transportation.

ABB, Uniper Sweden and the port of Luleå have initiated a cooperation to establish a hydrogen hub in Luleå aiming to further develop the hydrogen economy in the northern parts of Sweden (ABB, 2021). The project is planning to build a large-scale facility for electrolysis to generate fossil free hydrogen primarily dedicated for maritime applications. Any surplus hydrogen is suggested to be utilized in local industries in the Norrland region. By 2027, the expected production capacity is 33 tonnes per day. Future benefits include providing support for the transition of freight transport from road to sea. Furthermore, in addition to hydrogen production there will be infrastructure in place to meet the need for storage and distribution in the port (ABB, 2021).

Plagazi AB is developing a green-hydrogen-from-waste plant in Köping with a capacity of 12,000 tons of green hydrogen annually (corresponding to 16 tons per day) by converting 45,000 tons of waste (Plagazi, 2022). Plagazi claims that 70 percent of the energy needed to produce the hydrogen stems from waste, thus making it a good initiative to utilize waste. Compared to the cost of traditional electrolysis technology, the cost for waste-to-hydrogen is estimated to be 75 percent lower (Plagazi, 2022).

As can be seen in Table 9.1 several of the identified projects in Sweden are located in the vicinity of ports or the sea but only on project specifically mentions maritime application.

**Table 9.1 - An overview of identified projects in Sweden. Light blue color = project located <20 km from port or sea. Dark blue color = maritime applications mentioned in communications from involved companies. Italic text = hydrogen production dedicated for other purposes (e.g., methanol production or steelmaking). Bold text=includes hydrogen conversion to ammonia.**

| Location | Scale (tonnes hydrogen per day) and year* | Status |
|---|---|---|
| *Boden* | *365 tpd (14 600 TJ/yr) in 2024* | *Preparing environmental permit application* |
| **Luleå-Boden** | **281 tpd (11 232 TJ/yr) in 2026** | |
| *Lysekil* | *234 tpd (9 360 TJ/yr)* | *Under investigation* |
| *Gällivare* | *164 tpd (6 560 TJ/yr) in 2026* | *Waiting for environmental permit* |
| Luleå | 33 tpd (1 320 TJ/yr) in 2027 | Progressed to second round of Swedish IPCEI (important project of common European interest) |
| *Örnsköldsvik* | *32 tpd (1 280 TJ/yr) in 2024* | *Final investment decision to be taken in 2022* |
| Southern Sweden | 23 tpd (936 TJ/yr) | Applying for IPCEI (important project of common European interest) |
| Köping | 16 tpd (659 TJ/yr) | Prestudy 2020. 2021- apply for environmental permit |
| *Stenungsund* | *12 tpd (468 TJ/yr) in 2025* | *Second step in EU Innovation Fund application rounds* |
| - | 8 tpd (318 TJ/yr) in 2022 | 71 MSEK financing from Swedish Energy Agency granted |
| Southern Sweden | 0.5 tpd (19 TJ/yr) in 2022 | Awaiting reply from Klimatklivet. Could start delivery in 2022 |
| Mariestad | 0.13 tpd (5 TJ/yr) | Up and running |
| | | |
| - | *0,1 tpd (4 TJ/yr)* | *Construction phase* |
| *Oskarshamn* | *0.5 (18 TJ/yr) tpd* | *Operating since 1992, cooling of generators and commercial sales* |
| *Piteå* | - | *Plan to start of production year 2022. Granted investment support from "Klimatklivet"* |
| *Umeå* | - | *Plan to start of production year 2022. Granted investment support from "Klimatklivet"* |
| *Gävle* | - | *Detailed engineering, plan to start production in 2023. Production for industry and transport* |
| *Malung* | *0.33 (13 TJ/yr) tpd* | *Plan to start production in 2023* |
| *Several locations* | | *Granted investment support from "Klimatklivet". Plans to start production 2024* |
| *Ånge* | *13 (526 TJ/yr) tpd* | *Letter of intent between RES and municipality. Plans to start production 2024* |
| *Söderhamn* | *395 (15 800 TJ/yr) tpd* | *Memorandum of understanding signed with between companies. Plans to start production 2025.* |
| *Karlstad* | *3 (130 TJ/yr) tpd* | *Pre-feasibility study conducted* |

*Capacities expressed as $MW_e$ has been converted to tonnes per day (tpd) hydrogen. Capacities has been converted to annual fuel capacities (TJ/year) assuming 8000 full load hours. If several capacities are expressed, the one used when adding up national total capacities is underlined.

Despite many projects and initiatives, distribution and storage of hydrogen poses a challenge. The Swedish Energy Agency has recently published a proposal for an overall strategy for the role of hydrogen in the Swedish energy system (Swedish Energy Agency, 2021b). The strategy states that there is a need to develop storage technology adapted for Swedish conditions. Sweden for example lacks natural geological formations such as salt caverns for hydrogen storage. Storage of hydrogen is expected to take place in conventional hydrogen storage tanks near use. The lined rock cavern (LRC) technology is already used for storage of natural gas and can offer more large-scale storage, but the technology needs to be developed for hydrogen and undergo thorough testing and evaluation. Within the project HYBRIT20 LCR is investigated as a pilot project.

Nevertheless, in addition to technological development, further development of national and international rules and standards for handling challenges regarding safety, permit and acceptance issues is needed if underground pressurized facilities are to be implemented on a larger scale (Swedish Energy Agency, 2021a). Pressurized hydrogen can be distributed in pipes but also stored there when it is not needed. However, up to present Sweden does not have an expanded hydrogen network (Energigas Sverige, 2021). The hydrogen strategy also suggests it may be relevant to investigate hydrogen storage outside the country's borders, mainly within the Nordic region (Swedish Energy Agency, 2021b).

## 9.3 Norway

Norway is the leading Nordic country when it comes to number of plans and development of hydrogen projects identified in this mapping. As displayed in

Table 9.2 (and Table A2 in the appendix), a total of 37 projects for green or blue hydrogen or ammonia projects are planned with a total production capacity of about 2 000 tonnes of hydrogen per day. It is also clear that the maritime sector could benefit from these, with a majority of the projects located close to ports/sea and/or having explicitly mentioned marine transport as an offtake opportunity. However, this includes everything from projects specifically dedicated for maritime applications to projects that are dedicated to other applications but where potential surplus hydrogen is mentioned as possible to use for shipping and where the site is located close to a small port or have access to inland waterways.

Two notable projects in Norway are the ones by Horisont Energi and Yara. In the Barents Blue project, Horisont Energi are planning to build a plant in Hammerfest in northern Norway, capable of producing 3000 tonnes of blue ammonia per day (or 600 tpd hydrogen) (Horisont Energi, 2021a). With hopes of reaching a final investment decision (FID) in the end of 2022, plant operation could start in 2025 (Horisont Energi, 2021b). In the other end of the country, Yara has announced plans of converting their ammonia plant in Porsgrunn from the current feedstock of natural gas to a green hydrogen plant based on electrolysis (Yara, 2021). A smaller electrolyser pilot of 25 MW is already planned for commercial start-up in 2023 and, if public co-funding and regulatory framework comes in place, the full-scale plant with a 450 MW electrolyser could produce 1 100 tpd of green ammonia (or 211 tpd hydrogen) in 2026 (Ammonia Energy, 2020). Both the Barents Blue and Yara projects will be located by the sea, with opportunities for distribution by ship to large ports in both Norway, Sweden and Western Europe.

Projects can be connected to the sea and ports to varying degree. Concerning distribution possibilities to maritime applications, an advantage for the Norwegian case is that a large majority of projects are located close to sea. Some projects are located close to actual ports, while some are merely on sites with access to ship transport. This close access to the sea might however be important as the Norwegian hydrogen roadmap outlines the establishment of hydrogen hubs for maritime transport as the strategy towards 2025 (OED, 2021) and as plans for seaborne hydrogen distribution are being implemented (Enova, 2020; Zeeds, n.d.).

**Table 9.2 - An overview of identified projects in Norway. Light blue color = project located <20 km from port or sea. Dark blue color = maritime applications mentioned in communications from involved companies. Bold text=includes hydrogen conversion to ammonia. Italic text = hydrogen production dedicated for other purposes (e.g., methanol production or steelmaking).**

| Location | Scale (tonnes hydrogen per day) and year* | Status |
|---|---|---|
| **Hammerfest** | **600 tpd (24 000 TJ/yr) in 2025** | **Final Investment Decision end of 2022, start of operation in 2025** |
| **Porsgrunn** | **12 in 2023, 211 tpd (8 424 TJ/yr) in 2026** | **Letter of intent signed 2021, could be realized in 2026** |
| *Finnfjord* | *60 tpd (2 388 TJ/yr) in 2024* | *Final Investment Decision in end of 2021, two years construction* |
| **Berlevåg** | **1 tpd today, 47 tpd (1 872 TJ/yr) in 2024** | **2.5 MW demo operating, 100 MW feasibility study completed** |
| Rjukan | 23-37 tpd (no date) | Feasibility study started |
| *Tyssedal* | *23 tpd (936 TJ/yr) planned 2020, postponed* | *Feasibility study done 2016-17, Final Investment Decision postponed due to low quota prices* |
| Kvinnherad | 10-20 tpd (800 TJ/yr) (no date) | Cooperation agreement in place 2019 |
| Langemyr | Stepwise from 5 tpd in 2023 to 20 tpd (800 TJ/yr) in 2024-2025 | Feasibility study completed |
| Kollsnes | 1 tpd in 2022, 15 tpd (600 TJ/yr) in 2024 | 1 tpd facility purchased, start operation in 2022 |
| Glomfjord | 1 tpd in 2023, scale to 10 tpd (400 TJ/yr) | Letter of intent signed in 2020 |
| Meråker | 10 tpd (800 TJ/yr) in 2024 | Feasibility study completed |
| Kristiansand | 3 tpd (120 TJ/yr) in 2023 | Pre-study ongoing |
| Kjerlingland | 1-3 tpd (120 TJ/yr) (no date) | Pre-study ongoing |
| Fiskå | 1 tpd (40 TJ/yr) in 2022 | Submitted application for building permit |
| Svelgen | 0.33 tpd (13 TJ/yr) in 2022 | Can be realized in 2022 after a study in end of 2021 |
| Trondheim | 0.3 tpd (12 TJ/yr) in place | Already in place |
| *Porsgrunn* | *10 million tonnes aviation fuel from 2022* | *Front-end engineering and design to be completed in end of 2021* |
| ~~Mongstad~~ | ~~6 tpd LH2~~ | ~~Planned for start in 2024~~. Canceled. |
| Hellesylt | 0.7 tpd (estimate) | Planned for start in 2023 |
| *Mo i Rana* | *N/A* | *Production start in 2022. Industrial use, steel production* |
| *Mosjøen* | | *2024* |
| ***Herøya*** | ***1150 (46000 TJ/yr) tpd*** | ***Production plans for ammonia*** |
| *Sauda* | | *Plans to start production in 2027* |
| ***Slagentangen*** | ***5.5 (220 TJ/yr) tpd*** | ***Deal signed in june 2022, investigate the potential to produce and distribute green hydrogen and ammonia at Slagen Terminal. Production start 2030*** |
| *Mosjøen (Nesbruket)* | *42 (1670 TJ/yr) tpd* | *Planned. November 2021. Working on detail projecting and regulatory plans. Plans to start production in 2025* |
| *Mosjøen (Holandsvika)* | *35 (1425 TJ/yr) tpd* | *Planning phase. Plans to start production in 2025* |

| | | |
|---|---|---|
| *Egersund* | *15 (600 TJ/yr) tpd* | *Plans to start production in 2023* |
| *Bodø* | *15 (600 TJ/yr) tpd* | *Plans to start production in 2025* |
| *Kvinnherad* | *15 (581 TJ/yr) tpd* | *Cooperation agreement signed in 2019. Plans to start production within 2030* |
| *Bodø* | *14 (550 TJ/yr) tpd* | *Plans to start production by 2030* |
| *Rørvik* | *5 (220 TJ/yr) tpd* | *Pilot facility to be ready in early 2023. Plans to start production in 2025* |
| *Glomfjord* | *8 (320 TJ/yr) tpd* | *Plans to start production* |
| *Kristiansand (Fiskå)* | *8 (320 TJ/yr) tpd* | *Plans to start production in 2027* |
| *Rafnes* | *8 (320 TJ/yr) tpd* | |
| *Hitra* | *5 (200 TJ/yr) tpd* | *Plans to start production in 2027* |
| *Bodø* | *5 (200 TJ/yr) tpd* | *Plans to start production in 2030* |
| *Mosjøen* | *5 (190 TJ/yr) tpd* | *Plans to start production 2024* |

* Capacities expressed as $MW_e$ has been converted to tonnes per day (tpd) hydrogen. Capacities has been converted to annual fuel capacities (TJ/year) assuming 8000 full load hours. If several capacities are expressed, the one used when adding up national total capacities is underlined.

## 9.4 Finland

In Finland there are approximately a dozen sites dedicated for producing hydrogen and a few sites where hydrogen is produced as a by-product from other processes. Most of these facilities uses steam methane reforming (SMR) or partial oxidation (POX) of natural gas without carbon capture, and thus do not fill the criteria to be included in this mapping. Steam reforming and partial oxidation accounts for 99% of the dedicated hydrogen production and less than 1% is produced via water electrolysis (Business Finland, 2020). Table 9.3 (and Table A3 in the appendix) provides an overview of the four identified green hydrogen projects in Finland and below follows a presentation of projects based in Finland focusing on green hydrogen production. One of the identified projects specifically aim for producing hydrogen for maritime application.

The ferries trafficking the Åland archipelago account for a large share of the local $CO_2$ emissions and for that reason has Flexens, a Finnish project development company, conducted a feasibility study on green hydrogen production using wind power and its application as fuel for the ferries in the archipelago (Hong Liang, 2020). The production of green hydrogen in the Åland archipelago is expected to be competitive compared to fossil fuels due to the local favorable conditions for wind power production (Deltamarin, 2021). The feasibility study was conducted in 2020 and an application to EU Innovation Fund has been made. Current time estimates indicate a project realization at the earliest in the beginning of 2024 (Flexens, 2020).
The company AW-Energy has announced a strategy to use wave power as complement to solar or wind power for green hydrogen production in Finland. The AW-Energy WaveRoller is a product converting wave energy to electricity and the strategy is to combine the WaveRoller with a solar-powered hydrogen. This is expected to provide benefits in terms of significantly reduced total production cost and reduced land area use (AW-Energy, 2021).

Four parties, Wärtsilä Finland, Vaasan Sähkö and EPV Energia and the City of Vaasa have initiated a project aiming to utilize emission-free hydrogen in power generation, industry, and traffic. The project is seeking to build a power-to-x-to-power system in Vaasa where renewable energy will be used to produce green hydrogen. The produced hydrogen can then be used for traffic applications and electricity production. In the future, the hope of EVP is to store any excess over production of renewable energy as hydrogen for later use. The next step for the project partners is to investigate further funding during 2021 to be able start the project (Wärtislä, 2021).

Hitachi ABB Power Grids and P2X Solutions have entered a partnership agreement to build an industrial-scale green hydrogen production plant in Finland. The plant size is designed for 20 MW, 9.4 tonnes per day. During 2021 suitable locations for the production plant was investigated and implementation is under planning. One of the project aims is to provide a hydrogen production facility, that can be replicated on other locations both in Finland and internationally. The plant is estimated to be taken into operation earliest in 2024 (FuelCellWorks, 2021).

**Table 9.3 - An overview of identified projects in Finland. Light blue color = project located <20 km from port or sea. Dark blue color = maritime applications mentioned in communications from involved companies.**

| Location | Scale (tonnes hydrogen per day) and year* | Status |
|---|---|---|
| Åland | Not mentioned in official sources | Project realization is expected by 2024 |
| Vaasa | Not mentioned | Follow up on funding to reach final agreement for starting project |
| - | 9.4 tpd (374 TJ/yr) | Awaiting response from government on investment support. Hitachi ABB Power Grids and P2X Solutions |
| - | Not mentioned | Announced strategy to use wave energy to reduce production costs. Wave-Roller and HydrogenHub |
| Kokkola | 38 tpd (1500 TJ/yr) | In operation since 2014, for industry and transport |
| Harjavalta | 8 tpd (335 TJ/yr) | Plans to start production in 2024 |
| Pori | 8 tpd (335 TJ/yr) | Plans to start production in 2026 |
| Kotka | 17 tpd (670 TJ/yr) | Plans to start production in 2026 |
| Joensuu | 20 tpd (840 TJ/yr) | Plans to start production in 2027 |
| Kokkola | 125 tpd (5000 TJ/yr) | Plans to start production in 2027 |
| Porvoo | 275 tpd (10960 TJ/yr) | Plans to start production within 2030 |
| Voikkaa | 27 tpd (1090 TJ/yr) | Plans to start production within 2030 |
| Oulu | 27 tpd (1090 TJ/yr) | Plans to start production within 2030 |
| Oulu | 27 tpd (1090 TJ/yr) | Plans to start production within 2030 |
| Harjavalta | 2.7 tpd (110 TJ/yr) | Plans to start production within 2030 |
| Äetsä | 27 tpd (1090 TJ/yr) | Plans to start production within 2030 |
| Hämeenlinna | 2.7 tpd (110 TJ/yr) | Plans to start production within 2030 |
| Joutseno | 27 tpd (1090 TJ/yr) | Plans to start production within 2030 |
| Kuusankoski | 2.7 tpd (110 TJ/yr) | Plans to start production within 2030 |
| Hamina | 2.7 tpd (110 TJ/yr) | Plans to start production within 2030 |
| Porvoo | 275 tpd (10960 TJ/yr) | Plans to start production within 2030 |

* Capacities expressed as $MW_e$ has been converted to tonnes per day (tpd) hydrogen. Capacities has been converted to annual fuel capacities (TJ/year) assuming 8000 full load hours. If several capacities are expressed, the one used when adding up national total capacities is underlined.

Business Finland (2020) has published a national hydrogen roadmap, investigating production, potential, storage etc. of hydrogen in Finland. Regarding storage of hydrogen, Finland is lacking geological formations (e.g., salt caverns) for cost-effective storage (Business Finland, 2020). Line rock caverns (LRC) could however be a possibility. Compared to the cost of storage in salt caverns, the cost of LRC is not excessive (Business Finland, 2020). In addition to LRC it could also be possible with pipeline storage (Business Finland, 2020).

According to the hydrogen roadmap, Finland is currently lacking hydrogen pipeline infrastructure besides smaller scaled pipelines on industrial sites between two companies. However, Finland has a network of natural gas transmission pipelines. Following a decrease of 50 percent in use of natural gas in the past 15 years part of these pipelines could be repurposed and adapted to transportation of hydrogen. Nevertheless, this possibility needs to be extensively investigated (Business Finland, 2020).

Compared to other European countries transportation by tube trailers is considered competitive and cost-efficient in Finland (Business Finland, 2020). For European Agreement concerning the International Carriage of Dangerous Goods by Road (ADR) and non-ADR transport the weight limits are 68 and 76 tonnes respectively. This combined with the 34.5-meter length limit for vehicles will allow a 2000 kg payload (Business Finland, 2020).

## 9.5 Denmark

Denmark has made progress with several hydrogen projects in the pipeline, and some large-scale projects that could have a significant impact if fully implemented. As displayed in Table 9.4 (and Table A4 in the appendix), a total of 25 projects with stated production capacity plans have been identified, with a total capacity of about 2700 tonnes per day of hydrogen if implemented in full scale. Most of these projects are located close to sea and a few are dedicated to maritime applications.

Of the projects with stated production capacity plans, Green Fuels for Denmark in the Greater Copenhagen area is the largest. The unveiled plans describe a stepwise investment strategy, starting with 5 tonnes per day hydrogen production in 2023 dedicated for heavy-duty road transport, then moving on to 120 tpd in 2027 and 600 tpd in 2030 (Ørsted, 2021). For the later stages of the project, applications in maritime and aviation transport will be addressed, likely by converting the hydrogen into a liquid fuel, e.g., methanol or kerosene (Ørsted, 2021).

On the other side of Denmark, two major power-to-X (PtX) projects were announced during 2021 in Esbjerg – a city functioning as a supply base for offshore projects in the North Sea. In the beginning of the year, the investment fund Copenhagen Infrastructure Partners (CIP) announced plans of establishing “Europe’s largest PtX facility” in Esbjerg, with plans for 1 GW of electrolyser capacity in 2026 (State of Green, 2021). While the plant is branded as a PtX plant, producing hydrogen and converting it to ammonia for shipping and agriculture, it is possible that some of the hydrogen capacity might be used without conversion to ammonia. Adding to this project, the Swiss energy company H2 Energy Europe announced yet another largescale PtX project planned for Esbjerg (Esbjerg Municipality, 2021). Stepping up the ambitions in terms of time horizon, the company here claims that small-scale production could start already in 2022, scaling up to 1 GW in 2024, and while the CIP-project was aimed at ammonia production, this project will focus on hydrogen (Esbjerg Municipality, 2021).

Apart from these projects, there are two *energy island* projects in Denmark with the potential to contribute substantially to the national hydrogen production capacity. The idea is to have islands that can pool power from multiple offshore windfarms and connect these to several countries, instead of the conventional solution where each wind farm is separately connected to one country. This way, by windfarms sharing connections, large costs and environmental impact can be avoided. The windfarms can also get direct access to electricity bidding zones in several countries. In June 2020, the Danish Folketing decided to begin preparations for the construction of the two energy islands in the North Sea (new artificial island) and at Bornholm (existing island) in the Baltic Sea, with connected wind power capacities of 3 GW and 2 GW respectively (Energinet, n.d.). While the plans do not have any stated capacity plans for hydrogen production at this point, the declarations signed between Danish, German and Dutch ministers of climate mention the production of hydrogen as an important part of the plans (Energinet, 2020).

While several large projects are planned, a national hydrogen strategy taking a grip of the whole value chain – including distribution – is yet to be presented. The government of Denmark will release such a hydrogen strategy by the end of 2021. However, the national hydrogen organization, Brintbranchen (Hydrogen Denmark), has released its own strategy, analyzing the potential of large-scale hydrogen and PtX in Denmark

(Brintbranchen, 2020). The report states that depending on the electrolysis technology, large-scale hydrogen production will be located with access to transmission infrastructure, heating infrastructure etc. to optimize the interaction with the overall energy system (Brintbranchen, 2020). However, this may not always be at the same location as the end-user or large industries. It is a likely scenario that hydrogen will be produced at one location and used somewhere else. This depends on whether the hydrogen is to be used in its own form in transportation or energy or converted to other fuels or stored for later use (Brintbranchen, 2020).

The current Danish natural gas infrastructure can potentially be converted and adapted to hydrogen distribution. The report by Brintbranchen (2020) investigates Denmark's potential for exporting hydrogen to the European market but also state the need for an infrastructure that can facilitate transport to and from Germany to the rest of Europe (Brintbranchen, 2020).

**Table 9.4 - An overview of identified projects in Denmark. Light blue color = project located <20 km from port or sea. Dark blue color = maritime applications mentioned in communications from involved companies. Bold text=includes hydrogen conversion to ammonia.**

| Location | Scale (tonnes hydrogen per day) and year* | Status |
|---|---|---|
| Greater Copenhagen Area | 5 tpd in 2023, 117 in 2027, 608 tpd (24 336 TJ/yr) in 2030 | Power purchase agreement secured for first phase, dialogue with regulatory authorities ongoing |
| **Esbjerg** | **468 tpd (18 720 TJ/yr) in 2026** | |
| Esbjerg | 468 tpd (18 720 TJ/yr) in 2024 | To start small scale production in end of 2022 |
| Hobro-Viborg | 164 tpd in 2025, 468 tpd (18 720 TJ/yr) in 2030 | |
| Fredricia | 140 tpd (5 616 TJ/yr) in 2024 | Construction of 20 MW to start in late 2021, 300 MW await IPCEI (important project of common European interest) funding, hope reach Final Investment Decision by late 2022 |
| Kåstrup | 47 tpd (1 872 TJ/yr), no date | In preparation of Grant Agreement with CINEA |
| Mariagerfjord | 47 tpd (1 872 TJ/yr), no date | Accepted by municipal council |
| Kåstrup | 5.6 tpd (225 TJ/yr) in 2022 | Production start in 2022 |
| Aalborg | 5.6 tpd (225 TJ/yr) in 2022 | Pilot started |
| Copenhagen (Avedøre Holme) | 0.9 tpd (37 TJ/yr) in late 2021 | Final Investment Decision reached |
| Hobro | 0.6 tpd (22 TJ/yr) in operation | In operation |
| Brande | 0.2 tpd (7 TJ/yr) in 2021 | Production start in 2021 |
| 80 km offshore from Thorsminde | | Preparation of procurement of shared ownership of island, tenders for OSWF to come |
| Bornholm | - | - |
| - | - | Plans to start production by 2025 |
| Lemvig | 14 tpd (550 TJ/yr) | Plans to start production by 2024 |
| Esbjerg | 420 tpd (17000 TJ/yr) | Plans to start production by 2030 |
| Aabenraa | 42 tpd (1700 TJ/yr) | Plans to start production by 2025 |
| Vordingborg | 105 tpd (4200 TJ/yr) | Plans to start production by 2024 |
| Esbjerg | 2.5 tpd (100 TJ/yr) | Plans to start production by 2024 |
| Copenhagen | 685 tpd (27000 TJ/yr) | Plans to start production by 2030 |
| Holstebro | 42 tpd (1700 TJ/yr) | Plans to start production by 2025 |
| Idomlund | 63 tpd (2500 TJ/yr) | Plans to start production by 2025 |
| Handest | 20 tpd (840 TJ/yr) | Plans to start production by 2030 |
| Hejring | 15 tpd (560 TJ/yr) | Plans to start production by 2030 |
| Trelleborg | 3.3 tpd (130 TJ/yr) | Plans to start production by 2030 |

* Capacities expressed as MWe has been converted to tonnes per day (tpd) hydrogen. Capacities has been converted to annual fuel capacities (TJ/year) assuming 8000 full load hours. If several capacities are expressed, the one used when adding up national total capacities is underlined.

## 9.6 Iceland

Hydrogen is regarded as an important component in Iceland's plan of carbon neutrality by 2040. Since the country already has well-developed geothermal energy the potential for green hydrogen production is good (IAEE, 2008). There are several initiatives and Iceland's leading energy company, Landsvirkjun, have declared plans for several production plants as well as export to the European continent (Landsvirkjun 2020, 2021). Table 9.5 (and Table A5 in the appendix) summarizes the identified projects in Iceland, and they are also described in the following text.

One of the projects specifically aim for maritime application but then by using the hydrogen to produce methanol for maritime and other transport application. HS Orka and Hydrogen Ventures Ltd have stated their joint intentions to develop a green methanol production plant using green hydrogen for use in maritime applications as well as cars and other vehicles (Chemical Engineering, 2021). The green hydrogen will be produced using geothermal energy and the hydrogen will then be used to produce synthetic fuels. The first phase will have an initial capacity of 30 MW, 14 tonnes of hydrogen per day, followed by a more large-scale green hydrogen production in phase two (Think Geoenergy, 2021).

Landsvirkjun, the national power company, has initiated a process of developing a hydrogen production plant. The production plant, through electrolysis of water using renewable energy sources, will have a capacity of 10 MW (4.7 tpd $H_2$) with the potential of increasing capacity following increased demand. Based on the expansion of the electrolysis, the plant would have the capacity to provide hydrogen enough to cover the public transportation fleet in the Reykjavik area (Landsvirkjun, 2020).

Iceland holds great potential for producing renewable and sustainable energy, energy that could be exported in the future. Landsvirkjun and port authorities in Rotterdam, the Netherlands, have made a declaration of intent to export hydrogen from Iceland to the Netherlands. A preliminary review has been conducted and the involved parties assess export of hydrogen from Iceland to be possible by 2030 (Iceland Monitor, 2021). According to Landsvirkjun, the project could deliver around 200-500 MW (Landsvirkjun, 2021).

**Table 9.5 - An overview of identified projects in Iceland. Light blue color = project located <20 km from port or sea. Dark blue color = maritime applications mentioned in communications from involved companies.**

| Location | Scale (tonnes hydrogen per day) and year* | Status |
|---|---|---|
| Reykjanes | 14 tpd (561.6 TJ/ year $H_2$) | Announced plans for project |
| Ljósafoss | 4.7 tpd (187.2 TJ/year $H_2$) | Feasibility study announced |
| Reyðarfjörður, East Iceland | - | Plan to open a hydrogen production plant |
| - | 13 tpd (540 TJ/yr) | Expected production start 2023 |
| Reykjavik | - | Expected production start 2023 |
| Bakki, Húsavík | 290 tpd (11500 TJ/yr) | Expected production start 2024 |
| Reykjavik | - | Expected production start within 2030 |

* Capacities expressed as $MW_e$ has been converted to tonnes per day (tpd) hydrogen. Capacities has been converted to annual fuel capacities (TJ/year) assuming 8000 full load hours. If several capacities are expressed, the one used when adding up national total capacities is underlined.

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# A Appendix I - Compiled list of all identified hydrogen and ammonia project

This appendix contains a compiled list of all identified hydrogen and ammonia projects in the included Nordic countries. Light blue color = project located <20 km from port or sea. Dark blue color = maritime applications mentioned in communications from involved companies. Bold text=includes hydrogen conversion to ammonia. Italic text = hydrogen production dedicated for other purposes (e.g., methanol production or steelmaking). Data compiled in 2021 and project may have been canceled or changed. Tables below are indicative only.

Table A1. Sweden

| Project name | Location | Scale (tonnes hydrogen per day) and year* | $H_2$ source (green/ blue/other) | Hydrogen use | Status | Companies involved |
|---|---|---|---|---|---|---|
| *H2 Green Steel* | *Boden* | *365 tpd (14 600 TJ/yr) in 2024* | *Green* | *Steelmaking* | *Preparing environmental permit application* | *H2 Green Steel* |
| **Green Wolverine** | **Luleå-Boden** | **281 tpd (11 232 TJ/yr) in 2026** | **Green** | | **Memorandum of understanding signed with region and its investment agency** | **Fertiberia** |
| | *Lysekil* | *234 tpd (9 360 TJ/yr)* | *Green* | *Refinery* | *Under investigation* | *Preem, Vattenfall* |
| *HYBRIT Demo* | *Gällivare* | *164 tpd (6 560 TJ/yr) in 2026* | *Green* | *Steelmaking* | *Waiting for environmental permit* | *HYBRIT (Vattenfall, SSAB, LKAB)* |
| Botnialänken H2 | Luleå | 33 tpd (1 320 TJ/yr) in 2027 | Green | | Progressed to second round of Swedish IPCEI | Uniper, ABB, Luleå Hamn |
| *Liquid Wind* | *Örnsköldsvik* | *32 tpd (1 280 TJ/yr) in 2024* | *Green* | *Methanol production* | *FDI to be taken in 2022* | *Liquid Wind* |
| - | Southern Sweden | 23 tpd (936 TJ/yr) | Green | - | Applying for IPCEI | Rabbalshede Kraft |
| Green Hydrogen from waste | Köping | 16 tpd (658 TJ/yr) | Other (waste) | | Prestudy 2020. 2021- apply for environmental permit | Plagazi AB, Köping municipality |
| *Project Air* | *Stenungsund* | *12 tpd (468 TJ/yr) in 2025* | *Green* | *Methanol production* | *Second step in EU Innovation Fund application rounds* | *Perstorp, Uniper, Fortum* |
| - | *Hofors* | *8 tpd (318 TJ/yr) in 2022* | *Green* | *Steel rolling* | *71 MSEK financing from Swedish Energy Agency granted* | *Ovako, Volvo Technology AB Hitachi, ABB, HS Green Steel, Nel Hydrogen* |

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|---|---|---|---|---|---|---|
| - | Sothern Sweden | 0.5 tpd (19 TJ/yr) in 2022 | Green | - | Awaiting reply from Klimatklivet. Could start delivery in 2022 | Rabbalshede Kraft |
| - | Mariestad | 0.13 (5 TJ/yr) tpd | Green | Yes | Up and running | Väner Energi |
| *Zero Emissions Hydrogen Turbine Center* | - | *0,1 tpd (4 TJ/yr)* | *Green* | *Power production* | *Construction phase* | *Siemens Energy* |
| *Uniper* | *Oskarshamn* | *0.5 (18 TJ/yr) tpd* | *Pink* | | *Operating since 1992, cooling of generators and commercial sales* | *Uniper* |
| *Zelk Energy , Skoogs Energi* | *Piteå* | - | *Green* | | *Plan to start of production year 2022. Granted investment support from "Klimatklivet"* | *Zelk Energy , Skoogs Energi* |
| *Zelk Energy , Skoogs Energi* | *Umeå* | - | *Green* | | *Plan to start of production year 2022. Granted investment support from "Klimatklivet"* | *Zelk Energy , Skoogs Energi* |
| *Svea Vind Offshore* | *Gävle* | - | *Green* | | *Detailed engineering, plan to start production in 2023. Production for industry and transport* | *Svea Vind Offshore* |
| *Dala Vind* | *Malung* | *0.33 (13 TJ/yr) tpd* | *Green* | | *Plan to start production in 2023* | *Dala Vind* |
| *REH2, Nilsson Energy* | *Several locations* | | *Green* | | *Granted investment support from "Klimatklivet". Plans to start production 2024* | *REH2, Nilsson Energy* |
| *RES* | *Ånge* | *13 (526 TJ/yr) tpd* | *Green* | | *Letter of intent between RES and municipality. Plans to start production 2024* | *RES* |
| *Wpd, Lhyfe* | *Söderhamn* | *395 (15 800 TJ/yr) tpd* | *Green* | | *Memorandum of understanding signed with between companies. Plans to start production 2025.* | *Wpd, Lhyfe* |
| *Karlstad Energi, Everfuel* | *Karlstad* | *3 (130 TJ/yr) tpd* | *Green* | | *Pre-feasibility study conducted* | *Karlstad Energi, Everfuel* |

* Capacities expressed as $MW_e$ has been converted to tonnes per day (tpd) hydrogen. Capacities has been converted to annual fuel capacities (TJ/year) assuming 8000 full load hours. If several capacities are expressed, the one used when adding up national total capacities is underlined.

Table A2. Norway

| Project name | Location | Scale (tonnes hydrogen per day) and year* | $H_2$ source (green/ blue/other | Hydrogen use | Status** | Companies involved |
|---|---|---|---|---|---|---|
| **Barents Blue** | **Hammerfest** | **600 tpd (24 000 TJ/yr) in 2025** | **Blue** | **Ammonia production** | **Final Investment Decision end of 2022, start of operation in 2025** | **Horisont Energi** |
| **Yara Porsgrunn** | **Porsgrunn** | **12 tpd in 2023, 210 tpd (8 424 TJ/yr) in 2026** | **Green** | | **Letter of intent signed 2021, could be realized in 2026** | **Yara, Statkraft, Aker Clean Hydrogen** |
| *Green methanol* | *Finnfjord* | *60 tpd (2 388 TJ/yr) in 2024* | *Green* | *Methanol production* | *Final Investment Decision in end of 2021, two years construction* | *CRI, Statkraft, Finnfjord* |
| **HAEOLUS/ Green Ammonia Berlevåg** | **Berlevåg** | **1 tpd today, 47 tpd (1 872 TJ/yr) in 2024** | **Green** | | **2.5 MW demo operating, 100 MW feasibility study completed** | **Varanger Kraft, Aker Clean Hydrogen** |
| | Rjukan | 23-37 tpd (1 498 TJ/yr) (no date) | Green | LCOH project | Feasibility study started | Aker Green Hydrogen, Tinn municipality, Rjukan Naeringsutvikling |
| *TiZir* | *Tyssedal* | *23 tpd (936 TJ/yr) planned 2020, postponed* | *Green* | *Ilmenite reduction* | *Feasibility study done 2016-17, Final Investment Decision postponed due to low quota prices* | *TiZir, Greenstat* |
| | Kvinnherad | 10-20 tpd (800 TJ/yr) (no date) | Green | | Cooperation agreement in place 2019 | Gasnor, Sunnhordland Kraftlag, Kvinnherad kommune |
| Langemyr industriområde | Langemyr | Stepwise from 5 tpd in 2023 to 20 tpd (800 TJ/yr) in 2024-2025 | Green | | Feasibility study completed | Agder municipality, Kristiansand municipality |
| CCB Energy Park | Kollsnes | 1 tpd in 2022, 15 tpd (600 TJ/yr) in 2024 | Blue | | 1 tpd facility purchased, start operation in 2022 | ZEG Power, Coast Center Base, Equinor |
| Glomfjord Industrial Park | Glomfjord | 1 tpd in 2023, scale to 10 tpd (400 TJ/yr) | Green | | Letter of intent signed in 2020 | Glomfjord Hydrogen |

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|---|---|---|---|---|---|---|
| Meraker Hydrogen | Meråker | 10 tpd (400 TJ/yr) in 2024 | Green | | Feasibility study completed | |
| Glencore Nikkelverk | Kristiansand | 3 tpd (120 TJ/yr) in 2023 | Other | | Pre-study ongoing | Glencore Nikkelverk, Greenstat, Everfuel |
| Energi-hub Kjerlingland | Kjerlingland | 1-3 tpd (120 TJ/yr) (no date) | Green | | Pre-study ongoing | Greenstat, JB Ugland Fornybar Energi |
| Fiskå hydrogen-anlegg | Fiskå | 1 tpd (40 TJ/yr) in 2024 | Green | | Submitted application for building permit | Norconsult, Norled, Green H |
| | Svelgen | 0.33 tpd (13 TJ/yr) in 2022 | Other (silica production) | | Can be realized in 2022 after a study in end of 2021 | Elkem |
| | Trondheim | 0.3 tpd (12 TJ/yr) in place | Green | H2 filling station for automotive use | Already in place | ASKO |
| | *Porsgrunn* | *10 million tonnes aviation fuel annually in 2022* | *Green* | *Aviation fuel* | *Front-end engineering and design to be completed in end of 2021. Planned startup in 2025.* | Nordic Electrofuel |
| ~~*Aurora*~~ | ~~*Mongstad*~~ | ~~*6 tpd LH2*~~ | ~~*Green*~~ | | ~~*Planned for start in 2024*~~ | ~~BKK, Air Liquide og Equinor~~ Cancelled, March 2022 |
| *Hellesylt Hydrogen Hub* | *Hellesylt* | *1.3 tpd (estimate)* | *Green* | | *Planned for start in 2023* | Norwegian Hydrogen, (+project partners) |
| *Hydrogen Hub Mo* | *Mo i Rana* | *N/A* | *Green* | *Industrial use, steel production* | *Production start in 2022* | Statkraft, Celsa, Mo Industripark |
| | *Mosjøen* | | *Green* | | *2024* | Gen2 Energy https://gen2energy.com/production-sites/ |
| ***YARA*** | ***Herøya*** | ***1150 (46000 TJ/yr) tpd*** | ***Green*** | | ***Production plans for ammonia*** | **Hy2gen. Trafogira (sveitsisk) og Copenhagen** |

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|---|---|---|---|---|---|---|
| | | | | | | **Infrastructure Partners (dansk).** |
| | *Sauda* | | | | *Plans to start production in 2027* | *Kommunale Sauda KF* |
| | ***Slagentangen*** | ***5.5 (220 TJ/yr) tpd*** | ***Green*** | | ***Deal signed in june 2022, investigate the potential to produce and distribute green hydrogen and ammonia at Slagen Terminal. Production start 2030*** | ***North Ammonia, ExxonMobil, Green H AS, Grieg Edge*** |
| | *Mosjøen (Nesbruket)* | *42 (1670 TJ/yr) tpd* | *Green* | | *Planned. November 2021. Working on detail projecting and regulatory plans. Plans to start production in 2025* | *Gen2Energy* |
| | *Mosjøen (Holandsvika)* | *35 (1425 TJ/yr) tpd* | *Green* | | *Planning phase. Plans to start production in 2025* | *Gen2Energy* |
| | *Egersund* | *15 (600 TJ/yr) tpd* | *Green* | | *Plans to start production in 2023* | *HYDS (Hydrogen Solutions AS),* Dalane Energi and Egersund Næring and Havn Dalane Hydrogen |
| | *Bodø* | *15 (600 TJ/yr) tpd* | *Green* | | *Plans to start production in 2025* | *Hydrogen Solutions (HYDS),* SKL, local investor. Sembcorp Marine |
| | *Kvinnherad* | *15 (581 TJ/yr) tpd* | *Green* | | *Cooperation agreement signed in 2019. Plans to start production within 2030* | SKL, Kvinnherad kommune and Gasnor |
| | *Bodø* | *14 (550 TJ/yr) tpd* | *Green* | | *Plans to start production by 2030* | *Shell, Nordkraft og Linde* |
| | *Rørvik* | *5 (220 TJ/yr) tpd* | *Green* | | *Pilot facility to be ready in early 2023. Plans to start production in 2025* | *NTE and H2 Marine* |
| | *Glomfjord* | *8 (320 TJ/yr) tpd* | *Green* | | *Plans to start production* | *Glomfjord Hydrogen AS, Meløy Energi, Nel and Greenstat, Troms Kraft AS* |
| | *Kristiansand (Fiskå)* | *8 (320 TJ/yr) tpd* | *Green* | | *Plans to start production in 2027* | *Everfuel (dansk) and Greenstat , Hydrogen Hub Agder* |

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|---|---|---|---|---|---|---|
| | | | | | | *Elkem and Flencore Nikkelverk* |
| | *Rafnes* | *8 (320 TJ/yr) tpd* | *Green* | | | *Inovyn* |
| | *Hitra* | *5 (200 TJ/yr) tpd* | *Green* | | *Plans to start production in 2027* | *Trønder Energi Kraft , NTNU, Tensio TS, Kristiansund and Nordmøre Havn IKS, Hitra Industripark and Kysthavn and Hitra kommune Statkraft* |
| | *Bodø* | *5 (200 TJ/yr) tpd* | *Green* | | *Plans to start production in 2030* | *Project is lead by GreenH and SINTEF and Norconsult responsible for research and development* |
| *Norsk e-fuel* | *Mosjøen* | *5 (190 TJ/yr) tpd* | *Green* | | *Plans to start production 2024* | *Sunfire, climeworks, paul wurth, valinor, lux-airport* |

* Capacities expressed as $MW_e$ has been converted to tonnes per day (tpd) hydrogen. Capacities has been converted to annual fuel capacities (TJ/year) assuming 8000 full load hours. If several capacities are expressed, the one used when adding up national total capacities is underlined.

Table A3. Finland

| **Project name** | **Location** | **Scale (tonnes hydrogen per day) and year*** | **$H_2$ source (green/blue/other)** | **Status** | **Companies involved** |
|---|---|---|---|---|---|
| Power2AX | Åland | Not mentioned in official sources | Green | Project realization is expected by 2024 | Flexens Oy AB |
| Wind-power-to-hydrogen-electricity | Vaasa | Not mentioned | Green | Follow up on funding to reach final agreement for starting project | Wärtsilä, Vaasan Sähkö, EPV Energia, City of Vaasa |
| - | - | 9.4 tpd (374 TJ/yr) | Green | Awaiting response from government on investment support. Hitachi ABB Power Grids and P2X Solutions | Hitachi ABB Power Grids, P2X Solutions |
| - | - | Not mentioned | Green | Announced strategy to use wave energy to reduce production costs. Wave-Roller and HydrogenHub | AW-Energy |

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|---|---|---|---|---|---|
| Woikoski | Kokkola | 38 tpd (1500 TJ/yr) | Green | In operation since 2014, for industry and transport | |
| P2X Solutions | Harjavalta | 8 tpd (335 TJ/yr) | Green | Plans to start production in 2024 | P2X Solutions |
| - | Pori | 8 tpd (335 TJ/yr) | Green | Plans to start production in 2026 | Porin Prosessivoima Oy , Nordic Ren-Gas Oy |
| - | Kotka | 17 tpd (670 TJ/yr) | Green | Plans to start production in 2026 | Kotkan Energia Oy , Nordic Ren-Gas Oy |
| - | Joensuu | 20 tpd (840 TJ/yr) | Green | Plans to start production in 2027 | Savon Voima Oy , P2X Solutions |
| - | Kokkola | 125 tpd (5000 TJ/yr) | Green | Plans to start production in 2027 | Flexens Oy Ab and KIP Infra Oy , Gasgrid Finland, Nordion Energi |
| - | Porvoo | 275 tpd (10960 TJ/yr) | Green | Plans to start production within 2030 | Neste |
| - | Voikkaa | 27 tpd (1090 TJ/yr) | Green | Plans to start production within 2030 | Solvay Chemicals |
| | Oulu | 27 tpd (1090 TJ/yr) | Green | Plans to start production within 2030 | Eastman |
| | Oulu | 27 tpd (1090 TJ/yr) | Green | Plans to start production within 2030 | Nouryon |
| | Harjavalta | 2.7 tpd (110 TJ/yr) | Green | Plans to start production within 2030 | Linde |
| | Äetsä | 27 tpd (1090 TJ/yr) | Green | Plans to start production within 2030 | Kemira Chemicals |
| | Hämeenlinna | 2.7 tpd (110 TJ/yr) | Green | Plans to start production within 2030 | Linde |
| | Joutseno | 27 tpd (1090 TJ/yr) | Green | Plans to start production within 2030 | Kemira Chemicals |
| | Kuusankoski | 2.7 tpd (110 TJ/yr) | Green | Plans to start production within 2030 | Kemira Chemicals |
| | Hamina | 2.7 tpd (110 TJ/yr) | Green | Plans to start production within 2030 | Haminan Energia |
| | Porvoo | 275 tpd (10960 TJ/yr) | Green | Plans to start production within 2030 | Linde |

* Capacities expressed as $MW_e$ has been converted to tonnes per day (tpd) hydrogen. Capacities has been converted to annual fuel capacities (TJ/year) assuming 8000 full load hours. If several capacities are expressed, the one used when adding up national total capacities is underlined.

Table A4. Denmark

| Project name | Location | Scale (tonnes hydrogen per day) and year* | $H_2$ source (green/blue/other) | Status** | Companies involved |
|---|---|---|---|---|---|
| Green Fuels for Denmark | Greater Copenhagen Area | 5 tpd in 2023, 117 in 2027, 608 tpd (24 336 TJ/yr) in 2030 | Green | | Örsted and more |
| | Esbjerg | Small-scale production in end of 2022, potential full- scale 468 tpd (18 720 TJ/yr) in 2024 | Green | | H2 Energy Europe |
| **-** | **Esbjerg** | **468 tpd (18 720 TJ/yr) in 2026** | **Green** | | **CIP, Örsted and more** |
| Green Hydrogen Hub Denmark | Hobro-Viborg | 164 tpd in 2025, 468 tpd (18 720 TJ/yr) in 2030 | Green | | Eurowind Energy, Corre Energy, Gas Storage Denmark |
| HySynergy | Fredricia | 140 tpd (5 616 TJ/yr) in 2024 | Green | Construction of 20 MW to start in late 2021, 300 MW await IPCEI funding, hope reach Final Investment Decision by late 2022 | Everfuel, Shell and more |
| GreenHySc ale | Kåstrup | 47 tpd (1 872 TJ/yr), no date | Green | In preparation of Grant Agreement with CINEA | Greenlab, Green Hydrogen Systems, Energy Cluster Denmark, Lhyfe, Siemens Gamesa, Equinor, DTI, Imperial College London, Quantafuel, Euroquality |
| | Mariagerfjord | 47 tpd (1 872 TJ/yr), no date | Green | Accepted by municipal council | Eurowind |
| - | Kåstrup | 5.6 tpd (225 TJ/yr) in 2022 | Green | Production start in 2022 | GreenLab, Eurowind Energy, GreemHydrogen, Norlys Holding, RE:Integrate Aps and more |
| Power2Met | Aalborg | 5.6 tpd (225 TJ/yr) in 2022 | Green | Pilot started | Green Hydrogen Systems, Aalborg University, Hydrogen Valley, O.ON, NGF |

| | | | | | |
|---|---|---|---|---|---|
| | | | | | Nature Energy, Drivkraft Danmark, Reintegrate, Rockwool, Process Engineering, Holtec Automatic-Nord, Lillegaarden EL |
| H2RES | Copenhagen (Avedøre Holme) | 0.9 tpd (37 TJ/yr) in 2021 | Green | Final Investment Decision reached | Örsted, Everfuel, NEL and more |
| HyBalance | Hobro | 0.6 tpd (22 TJ/yr) in operation | Green | In operation | Air Liquide, Cummins, Centrica, Hydrogen Valley, Ludwig-Bölkow-Systemtechnik |
| - | Brande | 0.2 tpd (7 TJ/yr) in 2021 | Green | Production start in 2021 | Siemens Gamesa, Brande Brint |
| Energy Island - North Sea | 80 km offshore from Thorsminde | | Green | Preparation of procurement of shared ownership of island, tenders for OSWF to come | Energinet and more to come |
| Energy Island - Baltic Sea | Bornholm | - | Green | - | Energinet and more to come |
| - | - | - | Green | Plans to start production by 2025 | Haldor Topsøe |
| | Lemvig | 14 tpd (550 TJ/yr) | Green | Plans to start production by 2024 | - |
| | Esbjerg | 420 tpd (17000 TJ/yr) | Green | Plans to start production by 2030 | H2 Energy Europe |
| | Aabenraa | 42 tpd (1700 TJ/yr) | Green | Plans to start production by 2025 | Port of Aabenraa |
| | Vordingborg | 105 tpd (4200 TJ/yr) | Green | Plans to start production by 2024 | Arcadia eFuels ApS |
| | Esbjerg | 2.5 tpd (100 TJ/yr) | Green | Plans to start production by 2024 | European Energy |
| | Holstebro | 42 tpd (1700 TJ/yr) | Green | Plans to start production by 2025 | Everfuel |
| | Idomlund | 63 tpd (2500 TJ/yr) | Green | Plans to start production by 2025 | Skovgaard Energy |
| | Handest | 20 tpd (840 TJ/yr) | Green | Plans to start production by 2030 | Eurowind |
| | Hejring | 15 tpd (560 TJ/yr) | Green | Plans to start production by 2030 | Eurowind |
| | Trelleborg | 3.3 tpd (130 TJ/yr) | Green | Plans to start production by 2030 | Trelleborgs kommun, Lhyfe |

* Capacities expressed as $MW_e$ has been converted to tonnes per day (tpd) hydrogen. Capacities has been converted to annual fuel capacities (TJ/year) assuming 8000 full load hours. If several capacities are expressed, the one used when adding up national total capacities is underlined.

Table A5. Iceland

| Project name | Location | Scale (tonnes hydrogen per day) and year* | $H_2$ source (green/blue/other) | Status** | Companies involved |
|---|---|---|---|---|---|
| | Reykjanes | 14 tpd (561.6 TJ/ year $H_2$) | Green | Announced plans for project | HS Orka, Hydrogen Ventures Limited |
| - | Ljósafoss | 4.7 tpd (187.2 TJ/year $H_2$) | Green | Feasibility study announced | Landsvirkjun |
| - | Reyðarfjörður, East Iceland | | Green | Plan to open a hydrogen production plant | Landsvirkjun |
| - | - | 13 tpd (540 TJ/yr) | Green | Expected production start 2023 | Atome |
| - | Reykjavik | - | Green | Expected production start 2023 | Atmonia |
| - | Bakki, Húsavík | 290 tpd (11500 TJ/yr) | Green | Expected production start 2024 | Green Fuel |
| - | Reykjavik | - | Green | Expected production start within 2030 | Mannvit |

* Capacities expressed as $MW_e$ has been converted to tonnes per day (tpd) hydrogen. Capacities has been converted to annual fuel capacities (TJ/year) assuming 8000 full load hours. If several capacities are expressed, the one used when adding up national total capacities is underlined.