Decarbonisation of service vessels in offshore wind power through power-to-X self-sufficiency

A technology-, cost-, and climate impact analysis of hydrogen and battery systems

Ludvig Fredriksson & Clemens Kellander

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Sammandrag

Denna rapport undersöker möjligheterna att fasa ut fossila bränslen för servicefartyg i anslutning till en framtida flytande havsbaserad vindkraftspark vid området Utsira Nord i Norge, genom att producera egna energibärare i anslutning till parken med hjälp av elektrisk energi. Komprimerad vätgas, batterier, flytande vätgas, ammoniak, metanol, och biobränslen, identifieras som möjliga alternativa bränslen, av vilka de två förstnämnda undersöks ingående i denna rapport. Även inverkan av en parkansluten elektrisk laddningsboj undersöks. En litteraturstudie utförs och projektioner för framtida tekniska egenskaper gällande produktion, lagring, och drivlina, till året 2030, sammanställs. Nio fall konstrueras (inklusive tre bas-fall), innefattande drivlinor för två fartygstyper - crew transfer vessels (CTV) och service operation vessels (SOV) - samt för produktion och lagring. Historiska och framtida elpriser i Norge analyseras. Nuvärdeskostnaden, levelized cost of energy (LCOE) för vätgas, och bränslekostnad per MWh nyttig energi för fallen bestäms. Global uppvärmningspotential för komponenter samt energianvändning bestäms utifrån ett livscykelperspektiv. För CTV:er är vätgasalternativ brukliga vid korta transportsträckor. Batterilösningar är obrukliga till följd av dessa fartygs låga viktmässiga bärkraft och begränsade utrymme. För SOV:er är batterilösningar möjliga om en laddningsboj implementeras, vätgaslösningar är möjliga oavsett men gynnas av implementering av en laddningsboj. Vätgaslösningar är 2.9 till 4.0 gånger mer kostsamma än basfallen, och batterilösningar är 7.0 gånger mer kostsamma. Global uppvärmningspotential reduceras till en andel 0.17 till 0.05 av normalfallet – där vätgaslösningar presterar bäst. Laddningsbojar har potential att kostnadseffektivt sänka den globala uppvärmningspotentialen.

Nyckelord

Alternativa bränslen, komprimerad vätgas, batterier, produktion, energilagring, drift och underhåll, havsbaserad vindkraft, servicefartyg, utfasning av fossila bränslen, dekarbonisering, kostnad, global uppvärmningspotential, livscykel

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Abstract

This report examines the possibilities of decarbonising operation & maintenance vessels for a prospective floating offshore wind power park at the Utsira Nord site in Norway, through self-sufficient energy carrier production utilizing power-to-X-solutions. Possible alternative fuels are identified as compressed hydrogen, batteries, liquid hydrogen, ammonia, methanol, and biofuels, out of which the former two are the subject for thorough investigation in this report. The effects of an in-park electric charging buoy are also investigated. A literature study is conducted and projected technical properties for production, storage, and drivetrain for the year 2030 are compiled. Nine cases comprising drive trains for two vessel types – crew transfer vessels (CTV) and service operation vessels (SOV) -, production, and storage are constructed (including three base cases). Past and future electricity costs in Norway are analysed. Net present costs, levelized cost of energy (LCOE) of hydrogen, and fuel cost per MWh vessel output are determined. The global warming potential on a life cycle basis for components and energy use are determined. For CTVs, hydrogen is viable for short transits and battery solutions are not viable, as vessel mass and volume capacities are too low. For SOVs, battery systems are viable when combined with a charging buoy, hydrogen systems are viable regardless but also benefits from implementation of a charging buoy. Hydrogen solutions are 2.9 to 4.0 times more costly than the base cases, and battery-electric solutions are 7.0 times more costly. Global warming potential is reduced to 0.17 to 0.05 of the base cases, with hydrogen solutions performing the best. The inclusion of a charging buoy has potential to be a cost effective GWP abatement method.

Keywords

Alternative fuels, compressed hydrogen, battery, production, energy storage, operation and maintenance, O&M, offshore, wind power, service vessel, crew transfer vessel, CTV, service operations vessel, SOV, decarbonisation, global warming potential, life cycle

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Preface

This master thesis project was conducted during the autumn semester of 2022, as part of a MSc in Environmental Engineering at Lund University, Faculty of Engineering. The report was written under supervision by the Division of Environmental and Energy Systems Studies, Lund University, in collaboration with RWE Renewables.

First and foremost, we would like to thank our eminent supervisors Lars J. Nilsson (LTH), Jonas Algers (LTH) and Hanna Henriksson (RWE Renewables) for their support throughout the process and their many valuable comments on our work. Thank you also to our examiner Max Åhman (LTH) for your guidance and constructive feedback on the project.

We would also like to thank the amazing people at RWE Renewables for helping us along the way with our project. A special thank you goes out to Christian Fuglsbjerg, Alexander Granville, Matheus Barcelos Teles, Alexandra McLoughlin, Christoffer Falk, Ebba Philips John, and once again Hanna Henriksson, for taking the time to guide us through the many uncertainties we’ve come across throughout the project. Thank you also for the opportunity to work from the RWE Renewables office in Malmö, and for the inclusivity of the team there which it has been a privilege to experience.

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Abbreviations

AEC - Alkaline Electrolyser
Capex - Capital Expenditure
CCUS - Carbon Capture and Utilisation and/or Storage
CF - Capacity Factor
CFD - Contract for Difference
CGH2 - Compressed Gaseous Hydrogen
CTV - Crew Transfer Vessel
E-price - Electricity Price
E-buoy - Electric Charging Buoy
FAME - Fatty Acid Methyl Ester
FCEV - Fuel Cell Electric Vehicle
GHG - Greenhouse Gas
GWP - Global Warming Potential
HFO - Heavy Fuel Oil
HHV - Higher Heating Value
HVO - Hydrogenated Vegetable Oil
ICE - Internal Combustion Engine
IEA - International Energy Agency
IPCC - Intergovernmental Panel on Climate Change
LCOE - Levelized cost of energy
LHV - Lower Heating Value
LNG - Liquefied Natural Gas
LPG - Liquefied Petroleum Gas
MFO - Marine Fuel Oil
MGO - Marine Gas Oil
MPE - Ministry of Petroleum and Energy
NPC - Net Present Cost
Opex - Operational Expenditure
O&M - Operation and Maintenance
PEM - Proton Exchange Membrane
PEMEC - Proton Exchange Membrane Electrolyser
PEMFC - Proton Exchange Membrane Fuel Cell
SECA - Sulphur Emissions Control Areas
SOEC - Solid Oxide Electrolyser
SOFC - Solid Oxide Fuel Cell
SOV - Service Operation Vessel
WTG - Wind Turbine Generator

1 Introduction

1.1 Aim

The aim of this report is to investigate and analyze the viability of using renewable energy carriers for operation and maintenance (O&M) vessels at the prospective wind farm Utsira Nord, the site of which is to be auctioned by the Norwegian state. The energy carrier systems to be examined are limited to hydrogen and battery systems. The energy carrier systems are to be analyzed in technical, economical and environmental perspectives. The purpose of the report includes determining which technical components would be required for production, storage, fueling, and utilization of the energy carriers, as well as determining suitable locations for placement of facilities in connection to the prospective wind farm. In order to fulfill the aim, the following questions will be investigated:

- Which energy carrier systems would be most suitable as a replacement for fossil fuels in O&M vessels, in regards to production, storage and drive-train?
- Which technical components would be required for these systems and in what scale would they be needed?
- What would be the predicted costs for each system?
- What would be the environmental impacts of each system?
- How well does each system contribute to fulfilling the criteria of the Utsira Nord auction?

1.2 Delimitations

The energy carrier systems examined in depth in this report are limited to hydrogen and battery systems. This delimitation was made in accordance with supervisors at RWE Renewables, as these technologies are currently in use and being further developed within the company. For the particular application considered in this report - renewable energy carriers for the O&M vessels at the prospective wind farm Utsira Nord - hydrogen and battery systems have certain qualities that are advantageous compared to other renewable energy carriers. Namely, these systems require few energy conversion processes when converting electricity into energy carriers suitable for propulsion, which was considered a key aspect by RWE for this project.

2 Background

This section will cover the general background of the project such as policy, electricity market, site conditions, and maintenance work related to offshore wind power.

2.1 The Energy Transition

In order to achieve the goal of limiting global warming to well below 2°C, as agreed upon through the Paris agreement (UNFCCC 2016), reducing greenhouse gas emissions throughout society is critical and urgent. In illustrative emission pathways presented by the Intergovernmental Panel on Climate Change (IPCC), global emissions must be reduced by more than 90% by the year 2050 (relative to 2020) in order to achieve no overshoot of 2.0°C global warming (IPCC 2021).

In 2020, approximately 79% (IEA 2021d) of the global primary energy was supplied by fossil fuels such as oil, coal and gas. The emissions from these energy sources amount to more than two thirds of the total global greenhouse gas emissions (IEA 2021b). The emissions from the energy sector must drastically decrease in order to limit global warming to below 2 °C.

Renewable energy sources have the potential to produce usable energy with low carbon emissions. Especially in the power sector, energy sources such as wind, hydro and solar have promising capabilities of producing electricity at competitive costs with low emissions. In a net zero emissions-scenario presented by the IEA, renewables need to make up 88% of global electricity production in the year 2050 (IEA 2021c). In 2020, renewables made up 29% of global electricity production, meaning that substantial changes in the global power supply would be necessary in order to reach net zero by 2050.

2.2 Renewable Energy in Norway

Norway has an electricity supply of nearly 100% renewable energy, largely due to the country's beneficial geography which allows for plenty of hydropower. In 2020, hydropower provided 91.5% of the Norwegian electricity supply (DNV AS 2021). The remaining share was filled by 6.4% windpower, 1.6% gas, 0.1% coal and 0.4% other renewables. The availability of low-cost hydropower has enabled Norway to become a very electricity intensive country, with one of the highest electricity consumption per capita in the world. In particular, electricity consumption is high in the industrial sector and in heating of commercial and residential buildings.

Predictions made by DNV indicate that the Norwegian electricity consumption will grow by 67% in the time period 2020 to 2050, increasing from 140 TWh/yr to 234 TWh/yr. Domestic generation will grow by approximately 89% in the same time period, from 135 TWh/yr to 255 TWh/yr (ibid.). The increase in electricity generation will mainly be comprised of rapidly expanding wind power, which is predicted to increase to approximately 95 TWh/yr in 2050. Around 37% of this expansion in wind power is predicted to be floating offshore wind.

Production and usage of hydrogen is likely to increase in Norway in the coming years. The ample supply of renewable electricity allows for an expanding production of green hydrogen. DNV predicts that hydrogen electrolysis will consume 17 TWh electricity per year in 2040 and 38 TWh/yr in 2050 (ibid.). Hydrogen will likely have an increasingly large part to play in heavy industries and the transportation sector. It is predicted that the demand for hydrogen will increase slowly until the mid 2030's, where the demand is expected to increase more rapidly in the years following. DNV predicts that the hydrogen demand in 2050 will amount to approximately 20 TWh/yr. As the increased production of hydrogen in Norway will mainly be based on electrolysis, a substantial increase in electrolyser capacity and overall hydrogen infrastructure can be expected. Currently the electrolyser capacity and green hydrogen production in Norway is very small, especially in comparison to the predicted future volumes.

In 2022, the Norwegian government launched a green industrial initiative with the goal of vastly expanding green energy and industry in Norway (Ministry of Trade, Industry and Fisheries 2022). The aim is to become a global leader in this sector, and the government has made statements promising their dedication to the goals, with regards to financing and policy measures. Seven priority areas have been identified for the initiative, these are the value chains for offshore wind, batteries, hydrogen, carbon capture and storage, the process industry, the maritime industry, and forestry and the timber industry and other bioeconomy sectors. The government aims to create favourable conditions for industrial actors working in these fields. Of particular relevance to this report is the ambitions for the value chains for offshore wind, hydrogen, batteries, and the maritime industry. According to the report, Norway aims to be a leading developer in the value chains of the aforementioned technologies, as well as a pioneer in the field of zero-emission maritime transportation.

2.2.1 Electricity Market in Norway and Europe

Norway is divided into five electricity price areas. The function of these areas is to level the electricity price based on the availability of power in the local region. The availability of power in a region depends on the balance between electricity supply and demand. Electricity cannot be transferred unhindered throughout a power grid, as losses occur when transferring power over long distances, and there may be limitations in the grid transmission capacity at certain places. The electricity price areas therefore help weigh the electricity prices based on the local power balance. The price areas in Norway are shown in figure 1.

Electricity in Europe is purchased and sold on electricity markets. Electricity can be purchased on long term contracts, ensuring a stable supply of electricity to a user at a certain price for months or years in advance. On the other end, electricity can also be sold by the generating party on long term contracts, which is commonly called a power purchase agreement. Electricity is also traded on shorter time horizons, such as on the day-ahead market where electricity is traded 24 hours in advance, and on the intraday market where electricity is traded the same day as it is produced and consumed. The electricity price on these short-term markets is referred to as the spot price. In certain cases a contract for difference (CFD) is established, where the difference between market price and the cost of power generation is covered by e.g. a governmental body. This form of power trading can be applied to encourage the development of innovative power generation solutions.

Figure 1: Map over Norwegian electricity price areas.
The prospective wind farm Utsira Nord is to be located in price area NO2.
Image source: Statnett (2022b).

2.3 RWE Renewables

RWE Renewables is a subsidiary of the RWE Group, a global power company with the goal of meeting the increasing demand for electric power while reaching carbon-neutrality by 2040. As a part of this goal, RWE Renewables plan, design, establish, and operate renewable power generation facilities and energy storage solutions. Power generation entails solar photovoltaic parks and wind power plants both onshore and offshore, while energy storage includes battery systems and hydrogen solutions. Although power generation from these sources is carbon neutral at the plant, there are still greenhouse gas (GHG) emissions associated with e.g. extraction of materials, construction, and operation and maintenance - the last of which being the target for decarbonization in this report. For a near-future offshore wind power project, RWE Renewables aim to implement carbon neutral alternatives to the usual fossil fuel drive trains of the service vessels for O&M, and to do so self sufficiently. The project in question is located in proximity to the island of Utsira, 20 kilometers off the coast near Haugesund, Norway.

2.4 Utsira Nord Wind Farm

The Norwegian Ministry of Petroleum and Energy has announced that a marine area located by the island of Utsira will be designated for floating offshore wind power. The area is located 20 km west from the Norwegian coastline, near the cities of Haugesund and Stavanger in southern Norway. The designated area is located approximately 7 km from the island of Utsira. The wind farm will be located in the Norwegian electricity price area NO2. An illustration of the area intended for the wind farm is shown in figure 2. The area will likely be split into 3 smaller segments and auctioned to different wind farm operators. The total installed power production capacity of the area is planned to amount to approximately 1.5 GW, with each wind farm having a capacity of approximately 500 MW. The depth of the area generally exceeds 250 meters (Petrie et al. 2022), making conventional bottom-fixed turbine foundations unsuitable for the area. The wind farm area is therefore designated solely for floating wind turbines. Should RWE Renewables become one of the wind farm developers allowed to construct a wind farm at Utsira Nord, the turbines would be in a power range of 18 - 20 MW. A 500 MW wind farm would require approximately 25-28 turbines of this power capacity.

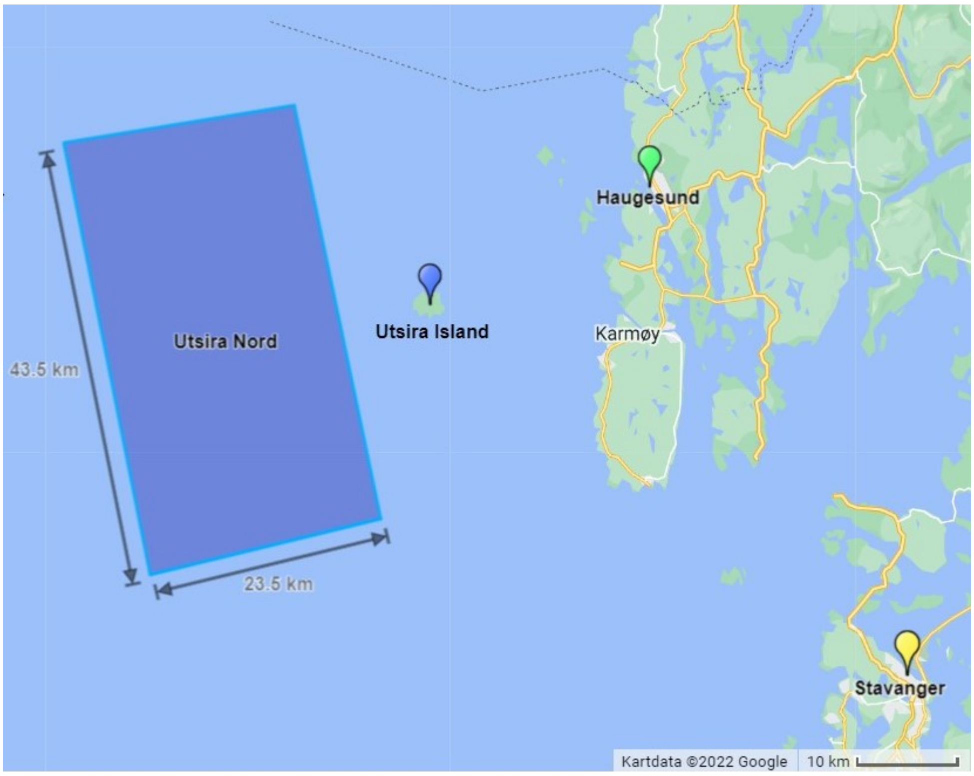


Figure 2: Map showing area intended for Utsira Nord wind farm.
(Map data: Google 2022)

The proximity of the wind farm area to Utsira makes the island a natural candidate for the energy infrastructure and service hub needed for an offshore wind farm. A large port is located in the town of Haugesund, approximately 40 km from the wind farm, making the town another potential base for service personnel and others that need to visit the area. Other potential ports for these purposes lay in the range of up to 200 km from the wind farm. The geographical layout of the electrical infrastructure (cables, substation and grid connection point) is not yet determined for the wind farm area. It is possible that a common substation will be constructed on Utsira Island, but several substation placements are being investigated. The grid connection point will likely be located near Karmøy. Four different cable layout scenarios have been suggested by Statnett, of which one scenario has cables passing near the harbour of Haugesund. The other three scenarios use other, mainly shorter paths, to reach the potential connection points near Karmøy (Statnett 2022a).

2.4.1 Auction Process and Criteria

In Norway, areas for offshore wind power are opened for exploitation by the Norwegian government and monarch in the highest governing body "Kongen i statsråd". After this, the Ministry of Petroleum and Energy (MPE), will handle the principal proceedings. The MPE usually divides the primary area for exploitation into smaller subdivisions and the maximum allowable installed effect is set for each subdivision. These subdivisions, or sites, are thereafter publicly announced and potential developers will compete to receive the sole right of establishing a project at the site. The announcement from the MPE contains the terms of the competition - which may be qualitative or quantitative - as well as time frames, qualification prerequisites, etc. (Ministry of Petroleum and Energy 2021)

The auction for Utsira Nord will be based on qualitative criteria, meaning that the qualities of the wind farm proposals will be of essence for winning the bid, rather than an auction relying purely on economic parameters. The preliminary terms for this auction were published on the 6th of December 2022 by the MPE. The qualities that are to be assessed for each bid include cost assessment, contribution to innovation and technology development, feasibility, sustainability, and contribution to local spillover developments (Ministry of Petroleum and Energy 2022a). Terje Aasland, the Minister of Petroleum and Energy, stated that "The Government wants investments in offshore wind to provide industrial development in Norway, facilitate innovation and technology development, and provide increased production of renewable power in

Norway." during a press conference where the framework for area allocation for Utsira Nord was presented (Ministry of Petroleum and Energy 2022b). The qualitative criteria for the Utsira Nord auction were drafted with the aim of achieving these goals. In total, 11 different consortia of developers are competing to best fulfill these criteria, however the process has not officially started as of the writing of this report, and criteria are still subject to change.

In order to fulfill the criteria, with particular regards to the categories "contribution to innovation and technology development, sustainability, and contribution to local spillover developments", utilizing self-produced alternative energy carriers for the O&M vessels at Utsira Nord could be a meaningful part of a bid for the wind farm area.

2.5 Operation and Maintenance in Offshore Wind Power

Whilst being one of the fastest growing sources of low-emission energy, offshore wind power offers special challenges when it comes to maintenance, availability, repairs, and infrastructure. To achieve maximum resource efficiency and profitability of a project, maximum availability of the component parts and the whole is essential. Availability can be defined as the state of being completely ready for operation. Availability necessitates maintenance, which necessitates transport and logistics of technicians and parts. Due to harsh conditions at sea, precautions must be taken to ensure the safety of the personnel carrying out maintenance work. When the sea is rough, over a certain threshold, transport from harbour and boarding of the wind turbines is avoided. Even at less rough seas, maintenance work is preferably avoided, as this requires the shutting down of the wind turbine generator (WTG) during conditions of relatively high winds and high productivity. This leaves a window for maintenance during periods of relative calm, and service vessels must be ready for high intensity operation during these windows. The operation of service vessels contribute to the over all global warming potential (GWP) associated with a wind power park. Emissions from the O&M vessels have been calculated to as high as 30% of the GWP/kWh from floating offshore wind power (Garcia-Teruel et al. 2022). However, this number includes activities and vessels such as heavy lift vessels, anchor handling tug supply vessels, and tugboats, whereas only the more regular activities of crew transfer vessels and service operations vessels (see section 3.6) are considered in this report. Nonetheless, the share of GWP from O&M vessels is significant, making it a valid target for emissions abatement.

3 Technical Background

The technical background will describe means of storing electrical, intermittent energy, via the conversion of electrical power into chemical potential in fuels. It will also describe the possible energy carriers, in terms of production, storage, fueling and utilisation, mainly focusing on batteries and hydrogen as pertaining to the RWE Renewables portfolio and the specifications of the Utsira Nord project. Storing, fueling and utilisation is closely connected to service vessel specifics, which will also be covered.

3.1 Technical Description of Service Vessels

There are two main types of vessels used for O&M in the offshore wind industry, Crew Transfer Vessels (CTVs) and Service Operation Vessels (SOVs). CTVs are smaller crafts used for daily service tours to wind farms. For a CTV to be sufficient, the site must not be situated too far from harbour, as twice daily travel times will become impractical, and the ocean must not be too rough as the stability during boarding of the WTG is limited. SOVs are larger ships that can house servicemen and crew for weeks at a time, intended for wind farms far out at sea where daily tours are not possible or wind farms where the ocean conditions are particularly rough. Due to their size, an SOVs are inherently more stable, and commonly also employ computer guided, self leveling gantries for WTG boarding. In the case of floating offshore wind power, the case for the SOVs becomes stronger, as there is no fixed foundation and demands on stability during WTG boarding become stricter. In table 1 below, typical characteristics for CTVs and SOVs are shown.

Table 1: Common characteristics of Crew Transfer Vessels (CTVs) and Service Operation Vessels (SOVs) used in the offshore wind industry.

Sources are listed in Appendix.

Category	**CTV**	**SOV**
Length (m)	15 - 30	90 - 120
Service Personnel	10 - 25	50 - 100
Ship Crew	3 - 4	10 - 30
Overnight Accomodation	No	Yes, 10 - 30 days
Total Engine Power (kW)	1 000 - 3 000	5 000 - 15 000
Maximum Significant Wave Height (m)	1.5 - 2.5	>2.5
Fuel Storage Volume (m^3)	5 - 25	500 - 2 000
Common Fuel Type	MFO	MGO
Maximum Range (km)	500 - 2 500	>5 000
Service Speed (knots)	20 - 25	10 - 15

Figures 3a and 3b show examples of a CTV and a vessel similar to an SOV.

(a) (b)

Figure 3: Photographs of service vessels.
CTV photo (a) by Paul Langrock, and of service vessel similar in size and function to an SOV (b) by Matthias Ibeler. Images accessed through RWE media data base.

3.2 Conventional Fuel and Propulsion Technology

Conventionally, marine vessels are powered by internal combustion engines (ICE) running on some form of fossil fuel, commonly heavy fuel oil (HFO), marine fuel oil (MFO) or marine gas oil (MGO). Two types of ICEs are common; 2-stroke engines which are usually applied for slow speed vessels, and 4-stroke engines which are applied for medium and high speed vessels (DNV GL 2019b). The 2-stroke ICEs are more expensive but offer a higher efficiency at around 45% as compared to the 4-stroke counterpart at around 40% (Korberg et al. 2021).

The above fuels differ somewhat in chemical composition and energy content, as do the emissions associated with their utilization, e.g., CO_2 and SO_x. In 2020, the permissible sulphur content in marine fuels was restricted generally to 0.5 wt% (DNV GL 2019a), and since previously certain areas have restrictions of 0.1 wt% (Transportstyrelsen 2014). The sulphur emissions control areas (SECA) in northern Europe with a 0.1 wt% sulphur limit are indicated in figure 4. Of the above discussed fuels, only the use of MGO complies with this limit. The cost of MGO has doubled in some European ports in the last year, laying close to 1000 €/tonne (Scrap Monster 2022b), but the future development is unclear. Other studies have applied a price of 500 €/tonne (Grzegorz Pawelec 2020), which agrees with bunker prices in European harbours over the last 5 years (Scrap Monster 2022a). This price equates to 43.9 €/MWh.

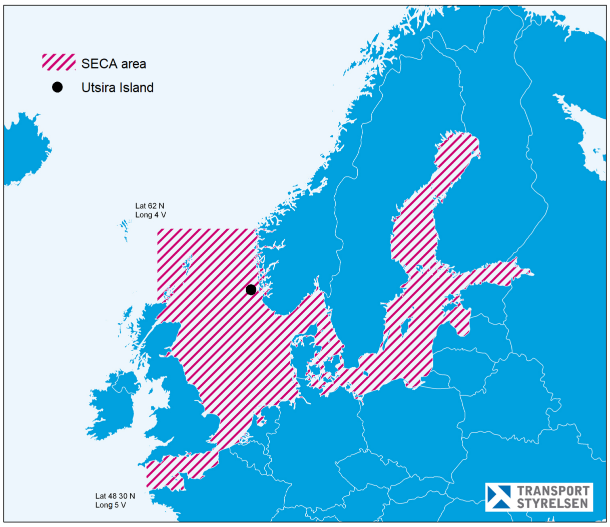


Figure 4: Sulphur emissions control areas (SECA) in northern Europe.
(Transportstyrelsen 2020)

3.3 Alternative Fuel Production and Propulsion Technologies

Electrical power can be converted and stored in a number of ways, but to be utilised for propulsion in a power train it must be stored either as a fuel or in batteries. Three principal technologies for propulsion of service vessels are ICEs, fuel cells and electrical motor, batteries and electrical motor, or a combination thereof. This report will focus mainly on batteries and fuel cells, in accordance with the delimitations described in chapter 1.2.

Theoretically, most combustible materials could be considered fuel, but only a few alternatives are practically viable when it comes to utilisation in modern vessels and production from renewable sources: hydrogen (H_2), ammonia (NH_3), methanol (CH_3OH), and longer hydrocarbon synthetic fuels. For all the latter, hydrogen is a precursor component, which means that the production chain for all of these fuels start at the same place.

3.4 Hydrogen

Hydrogen, H, is the smallest and lightest of the elements. Pure hydrogen is found in the form of a pair of hydrogen atoms in the hydrogen molecule, H_2, which is usually in gaseous phase as its critical point lies at -240 °C and 13 bar (Møller et al. 2017). This gas is non-toxic, as well as colour- and odorless. Hydrogen is readily oxidised, and the oxidation of H_2 with oxygen, O_2, into water, H_2O, releases energy which can be utilised to carry out work.

$$2H_2 + O_2 \rightarrow 2H_2O + Energy \tag{1}$$

This reaction releases a total 39.4 kWh per kg of H_2, this is the so called higher heating value (HHV). The lower heating value (LHV) denotes the available energy which remains after the water has been evaporated from the heat of the reaction, and is 33,3 kWh per kg of H_2 (Engineering ToolBox 2003).

3.4.1 Production

The production of hydrogen can be achieved through a number of pathways, most of which using fossil hydrocarbons as feedstock, with 68% of global hydrogen production stemming from natural gas, 16% from oil, and 11% from coal, totaling 95% being of fossil origin (DNV GL 2019a). There are many different technologies for attaining hydrogen from these sources, all of them leading to emissions of CO_2, following the principle formula below (El-Shafie, Kambara, and Hayakawa 2019).

$$C_nH_m + 2nH_2O \rightarrow nCO_2 + \left(\frac{m}{2} + 2n\right) H_2 \tag{2}$$

In theory, there are carbon-neutral pathways even when using fossil feedstock, such as when applying carbon capture and storage and/or utilisation (CCUS). In practise however, there are often GHG-emissions somewhere along the production chain, such as leaks of natural gas during extraction and transportation. Popular denotations for these pathways of hydrogen production are "gray" and "blue" hydrogen, referring to non-CCUS and CCUS pathways, respectively.

The pathways with the lowest GHG-emissions per unit hydrogen produced are those using water as feedstock, with electrolysis being the most applicable in connection to renewable power production. Hydrogen from electrolysis using renewable energy is commonly referred to as "green" hydrogen. The end result of electrolysis is the reverse of reaction (1) above, however different types of electrolysers exploit different chemical mechanisms and as such the reaction pathways will differ slightly. The simplest description of an electrolyser is that it consists of an electrolyte where ions may migrate, an anode, where oxidation occurs, and a cathode, where reduction occurs - as electric current is passed through the system (El-Shafie, Kambara, and Hayakawa 2019). Below, three different elctrolyser technologies are considered, and thereafter the key characteristics of which are summarised in table 2.

Proton Exchange Membrane electrolyser
The most proposed electrolyser type for the wind power sector is the proton exchange membrane electrolyser (PEMEC), due to its ability to handle fluctuating power supply and to start and stop operation within slim time-frames. The cold start up time for a PEMEC (from ambient temperature after long shut-down) is approximately 10 minutes, while the warm start up time (from idle or stand-by mode) is usually less than 10 seconds. In the PEMEC, the reaction can be described as follows - starting with the anode reaction: (Danish Energy Agency 2017)

$$2H_2O \rightarrow O_2 + 4H^+ + 4e^-$$

And the cathode reaction:

$$4H^+ + 4e^- \rightarrow 2H_2$$

With the end result being the production of hydrogen and oxygen.

$$2H_2O \rightarrow 2H_2 + O_2 \tag{3}$$

This process can occur under highly pressurised or low pressurised conditions, the latter requiring further compression of the output hydrogen gas for more optimal storage and utilisation. Compression of gas consumes energy, therefore it is preferable to employ a pressurised PEMEC, aiming at an output pressure of 350 bar to 700 bar. However, highly pressurised systems may pose safety concerns and impose increased degradation of the electrolyser (Salehmin et al. 2022). In comparison, an average output pressure for commercialized PEMEC is around 30 bar to 50 bar (ibid.). Regardless of working pressure, the water entering the system must have a high purity, or degradation will ensue quickly. In the case of sea water, desalination and water purification equipment is a necessary component, further increasing the energy demand (Danish Energy Agency 2017).

Alkaline Electrolysis Cell electrolyser
Another technological alternative is the alkaline electrolysis cell electrolyser (AEC), which has a higher degree of technological maturity, commercialisation, and efficiency as of today when compared to the PEMEC. As such, AEC are often less expensive and energy intensive compared to the PEMEC. However, the start-up time is longer and the response to fluctuating power supply is slower. The cold start up time for an AEC (from ambient temperature after long shut-down) is apporoximately two hours, while the warm start up time (from idle or stand-by mode) is usually less than 5 minutes. The electrolytical reaction is different when compared to the PEM reaction, but the end result is the same. (ibid.)

The cathode reaction:

$$4H_2O + 4e^- \rightarrow 2H_2 + 4OH^-$$

And the anode reaction:

$$4OH^- \rightarrow O_2 + 2H_2O + 4e^-$$

With the end result being the same as for the PEMEC - the production of hydrogen and oxygen.

$$2H_2O \rightarrow 2H_2 + O_2 \tag{4}$$

Solid Oxide electrolyser
Another electrolyser technology is the solid oxide electrolyser (SOEC), which differs from the two previously mentioned in that the input energy is a mix of electricity and heat. The overall and electrical efficiency of the SOEC is higher than for the PEMEC and AEC cases, but optimal operational temperatures are reached around 800-1000 °C. For the SOEC, the start-up times are longer - 12 hours cold and 15 minutes warm - the footprint larger, and the technology not as mature as for the AEC nor the PEMEC (Danish Energy Agency 2017). Due to the demand for high temperatures, this technology is not suited for coupling with wind power if a heat source is not accessible in connection to the site of hydrogen production.

Table 2: Summary of general characteristics of electrolysers.

(Danish Energy Agency 2017)

Types:	PEMEC	AEC	SOEC
Technological/commercial maturity*	High	Highest	Low
Cold start time	10 min	2 h	12 h
Warm start time	10 sec	5 min	15 min
Energy input	Electricity	Electricity	Electricity and heat

*as of 2022

3.4.2 Storage

Hydrogen can be stored in several different ways. The molecular properties of the substance does however make it more challenging to contain than many other energy carriers. Hydrogen gas has a very high energy content by weight, but due to the very low volumetric density of the gas it must be significantly compressed or cooled to very low temperatures in order to decrease the storage volumes. A downside of these methods is that compression and cooling requires energy, further adding to the energy losses associated with hydrogen energy conversion. Another challenge of hydrogen storage has to do with the size of the H_2 molecules. As it is the smallest molecule that exists, the gas can cause what is called hydrogen embrittlement. This means that the molecules can permeate into solid materials, causing embrittlement of the material and making it easier for cracks to form (Gangloff and Somerday 2012).

The most technologically mature techniques to store hydrogen are physical storage methods, such as compressed or cooled hydrogen stored in tanks or geological formations. Geological storage requires appropriate geological conditions, such as availability of bedrock or other impermeable formations. Another category of hydrogen storage techniques are called materials-based storage. These techniques rely on chemical mechanisms to store the H_2 molecules, but they have several factors making them less attractive than physical-based storage methods, as the technology for materials-based storage is still in a scientific development stage (Hydrogen Europe 2021).

Compressed hydrogen can be stored in small tanks often intended for mobile applications, in larger tanks for stationary storage, and in geological formations such as salt caverns or discontinued mines for large scale seasonal storage. Hydrogen gas is stored at pressures of up to 1000 bar, but storage at such high pressures requires very robust equipment and is more costly than storage at lower pressures. Generally it can be stated that the higher the pressure, the more expensive is the equipment required for storage. Compressing hydrogen usually results in an energy loss corresponding to approximately 10% of the hydrogen energy content (Barthelemy, Weber, and Barbier 2017).

There are four main types of tanks that can be used for small to medium scale storage of compressed hydrogen. These are:

- Type I: heavy vessel made entirely of metal, no outer composite wrapping.
- Type II: medium heavy vessel with inner liner in metal wrapped in a fiber-resin composite which strengthens the tank.
- Type III: lighter vessel with a thin metallic inner liner (usually aluminium), wrapped in a a fiber-resin composite which bears the pressure load.
- Type IV: lighter vessel with polymeric inner liner, wrapped in fiber-resin composite which bears the pressure load.

Generally, the tank types described above are cylindrical in shape. Of these tank models, Type I is the cheapest to produce, but it is also the heaviest and stores gas at lower pressures than the others (usually 150 to 300 bar). Type II can store hydrogen at higher pressures than Type I thanks to the reinforcement from the outer composite wrapping. Types III and IV are the lightest tanks and are able to store gas at pressures up to 700 and 1000 bar, respectively (Barthelemy, Weber, and Barbier 2017). These tanks are suitable for mobile applications due to their energy-dense storage capabilities, but they are also the most expensive vessel types. Types III and IV are used in existing FCEV's (Fuel Cell Electric Vehicles), where limiting size and weight is essential. Hydrogen in FCEV's is typically pressurized to either 350 or 700 bar.

Another hydrogen storage method that is considered well matured is liquified hydrogen (LH2). This method requires the hydrogen to be kept below its boiling point of -253°C. As this is an extremely low temperature, cryogenic technology is needed in order to achieve the required cooling. Liquefying hydrogen this way requires energy, increasing the energy losses associated with the hydrogen production chain. The energy demand for cryogenic storage of hydrogen amounts to approximately 25-40% of the hydrogen energy content (Langmi et al. 2022), which is a considerable energy loss. Another energy loss associated with LH2 storage, known as "boil-off", is due to heat transfer from the environment causing liquid hydrogen in the tank to boil. As these storage tanks are not built to withstand high pressures, hydrogen vapour must be let out into the air. This causes a slow loss of fuel that will deplete the tank if LH2 is stored for long periods of time. The main benefit of liquid hydrogen is the increased volumetric energy density, which is approximately 30% greater compared to hydrogen gas at pressures of 700 bar (Rivard, Trudeau, and Zaghib 2019a). This makes the liquid more suitable for applications where compact energy storage is required. However, the insulation and cooling equipment required to keep hydrogen at these low temperatures increase both the weight and the volume of the system. The cryogenic equipment also influences the cost of the storage system, the cost being significantly varied depending on the size of the storage system. Generally, storing hydrogen in a liquid state is most beneficial when the substance is to be transported over long distances in large quantities, such as long-haul road transport or freight shipping. The required insulation of LH2-tanks increases the thickness of the tank walls, meaning that larger tanks have a better energy to volume ratio.

Cryo-compression is another storage method that combines the properties of both compression and cryogenic storage. The main advantages of this method is that it can achieve the same volumetric energy density as cryogenic storage, while not needing to vent gaseous hydrogen thanks to the pressure-proof vessel. The method has good potential to be competitive in terms of gravimetric and volumetric storage capabilities, but it is still in a development phase and is more costly than compressed or cryogenic storage (Langmi et al. 2022).

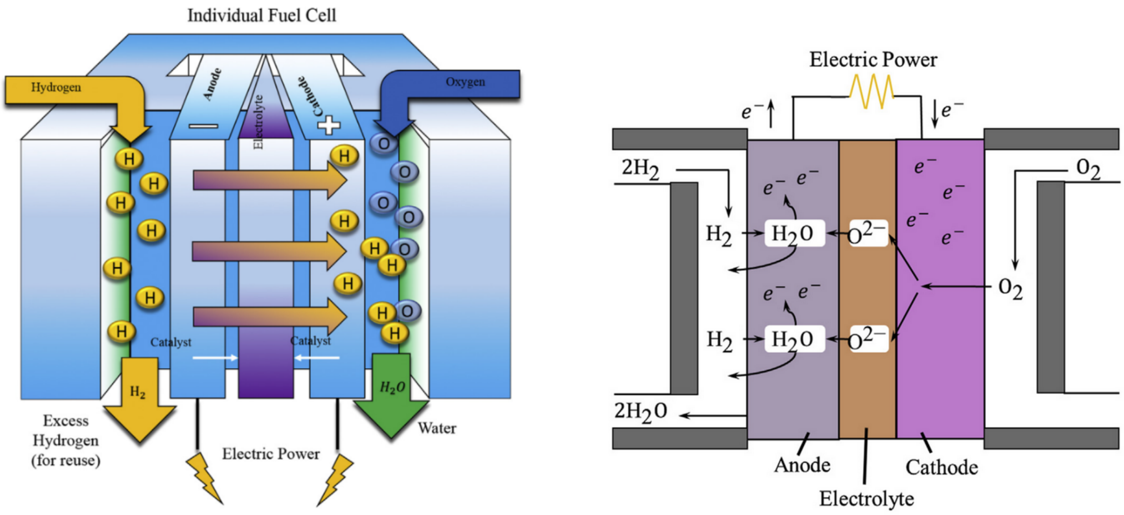
3.4.3 Fueling

Hydrogen refuelling can be carried out similarly to conventional combustion fuels such as gasoline and diesel. Gaseous and liquid hydrogen can be transferred from a stationary storage unit to a tank onboard a ship or vehicle by a hydrogen hose and pressure sealing nozzle. Gaseous hydrogen can be transferred by utilizing the pressure difference between the tank that needs refuelling and the stationary tank. This technique requires that the pressure in the stationary storage is higher than the desired pressure in the mobile tank, which typically is 350 or 700 bar. Another method for fuelling is to use hydrogen stored at lower pressures and compress it when transferring it to the mobile tank (Wurster et al. 2007).

3.4.4 Fuel Cells

A fuel cell can be described as an electrochemical machine, which converts the chemical potential in fuels into electrical work and heat. Fuel cells require a continuous inflow of fuel and oxygen to supply power. The fuel can be hydrogen or other hydrogen rich molecules, such as ammonia and methane, while oxygen is usually supplied via air. If hydrogen is used, the fuel cell can operate on this fuel directly, while some other fuels require chemical reformation to make the hydrogen more available to the fuel cell. In any case, the driving mechanism is the oxidation of hydrogen with oxygen into water, as described in reaction (1) above, but instead of releasing the energy through combustion, energy is released via the migration of ions and electrons - analogous to reverse electrolysis. Just as an electrolyser, a fuel cell principally consists of two electrodes, an anode and a cathode, connected internally by an electrolyte and externally by an electric circuit. Ions are transported from one electrode to the other via the electrolyte, while electrons are transported via the external circuit to provide work. Which of the two elements, hydrogen or oxygen, that is ionized, depends on the type of fuel cell (Sundén 2019e). For maritime application, the two most prominent types are proton exchange membrane fuel cell (PEMFC) and solid oxide fuel cell (SOFC).

The PEMFC, just as the PEMEC, has the ability to operate over varying loads, and is suitable for marine applications. The efficiency is around 60% and operation temperatures are relatively low at around 100 °C. In contrast, the SOFC is only viable in a hybrid solution together with some other power source. The reason is, that while efficiency is high at around 80 % the SOFC is more suitable for supplying a stable, unvarying, base load. The operating temperature is also higher, at around 800 °C to 1000 °C (Sundén 2019d). An offshore construction vessel, similar in size and power output to an SOV, with a 2 MW PEMFC, out of 7.5 MW of total installed power, has been developed by Norwegian ship manufacturer Ulstein but is as of yet not in operation (Ulstein 2021).



(a) (b)

Figure 5: Principle workings of fuel cells.
PEMFC (a) and SOFC (b): In the PEMFC, the hydrogen is ionized, and in the SOFC oxygen is ionized. (Sundén 2019d).

3.4.5 Hydrogen Internal Combustion Engines

Internal combustions engines (ICE) operate by converting chemical potential energy in a fuel via combustion with oxygen supplied from the air into mechanical energy. An ICE may be operated either with pure hydrogen gas as fuel or in duel fuel operation, i.e. with a mix of hydrogen and diesel, natural gas, or biogas. The characteristics of the energy conversion depends on the type and configuration of the engine, such as fuel mix ratio, how and where in the conversion the fuel is mixed, the stoichiometry of fuel to air, the type of ignition, etc. The ratio of hydrogen can also be varied over different engine loads for optimal performance (Boretti 2020). In dual fuel mode, the impacts on emissions such as NO_x, carbon monoxide, and hydrocarbons, as well as on efficiency, varies. Improvements regarding these parameters have been reported when running in dual fuel mode, but also the opposite (Deheri et al. 2020), (Chintala and Subramanian 2017). In pure hydrogen mode, a lower efficiency is cited by DNV GL (2019b), although with uncertainty. It is expected that the application of hydrogen ICEs may act as a transitional technology in the hydrogen integration process for marine vessels, but that fuel cells will eventually be preferred due to higher efficiencies and no emissions of NO_x, SO_x, or hydrocarbons (ibid.). There are currently O&M vessels on the market operating with hydrogen and diesel dual fuel ICEs (CMB.TECH 2022a).

3.5 Batteries

Batteries, just as fuel cells, operate by converting chemical potential energy into electric work and heat. In batteries however, all chemical constituents are held within the battery itself and no mass transfer with the surrounding takes place. The principal constituents are the electrodes - anode and cathode -, electrolyte, and external circuit. A battery provides electrical power when ionic electrochemical reactions are started at the electrodes and electrons simultaneously travel via the external circuit from the anode to the cathode to balance these reactions. In the case of rechargeable batteries, the chemical reactions taking place at the electrodes are reversible when an external voltage is applied. However, even though the reactions are reversible in theory, recharging a battery never perfectly reverts the molecular structure of the electrodes back to the original state, and degradation will occur over time. (Sundén 2019a)

Degradation and lifetime of a battery can be described in terms of the number of charge and discharge cycles it is expected to last. The degradation, and thus the expected number of cycles, depends on many parameters within both the surrounding environment and the operational patterns. In maritime application, high air humidity, saline environment, and vibrations are factors which might decrease the lifetime of batteries and also pose safety concerns (Sundén 2019c). One operational factor with high impact on expected lifetime is the depth of discharge (DOD), which describes the ratio of the full battery capacity which is discharged in a cycle. Utilizing a higher DOD on average over the lifetime will decrease the total number of cycles. For the general lithium-ion battery, equation 5 can be used to estimate the number of cycles (Gianfranco Burzio, Daniela Parena 2012).

$$N_{life} = a \cdot DOD^b \tag{5}$$

Where a and b equal 1331 and -1.825 respectively, and N_{life} is the total number of cycles. There are also other battery technologies, differing by their chemical constituents and structure. Depending on the structure and chemistry, a battery will display different characteristics when it comes to resistance to degradation, power density and energy density. Lithium-ion chemistries are the most common for rechargeable batteries in power trains. Figure 6 below shows the principle outline of a general lithium-ion battery cell.

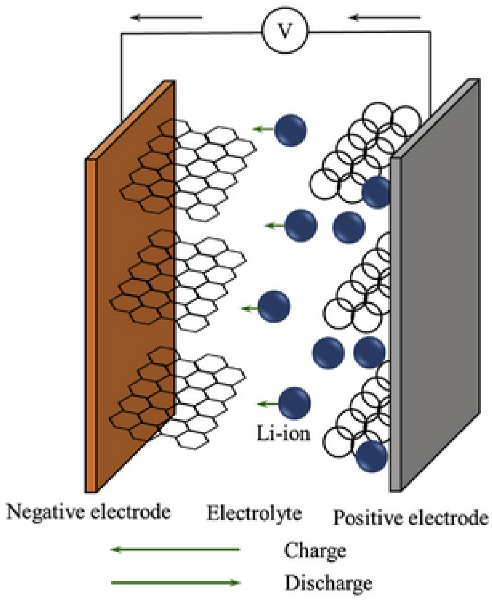


Figure 6: Principle outline of Li-ion battery cell.
(Sundén 2019a)

The chemical reactions occurring in batteries also generate heat. Because there is no mass transfer with the environment, heat is not automatically expunged via e.g., exhaust gases. If the temperature of a battery system reaches a critical level, a phenomena called thermal runaway can occur, where the chemical reactions inside the battery start to proceed uncontrollably, resulting in the development of extreme heat and fire, and toxic smoke. To avoid thermal runaway and other safety issues, developing and applying standards with effective safety systems is crucial (Sundén 2019c). For a battery to operate properly, a battery management system (BMS) must be applied, monitoring for example safe operating conditions and thermal status (Sundén 2019b). Safety systems and BMS add to the overall cost of battery solutions.

In maritime applications, pure battery solutions are often limited by the increasing size and cost for long fearing vessels. However, for shorter distances these parameters may fall within feasible limits. Another option granted by integrating battery power is the increase in optimization and controllability which it offers in a combined hybrid system together with another power source. For example, a battery can operate together with a fuel cell to shave peak loads or to handle spikes in power demand.

3.6 Other Alternative Energy Carriers

There are several alternative fuels that can be used in the maritime sector, besides hydrogen and batteries. Ammonia, methanol, biofuels, liquefied natural gas (LNG), and liquefied petroleum gas (LPG) are some examples of alternative fuels. There are pros and cons of each fuel type, and the availability and technical maturity varies. Two important properties of marine fuels is the gravimetric and volumetric energy density, as these aspects are crucial when designing vessels with long range and efficient storage utilization. Figure 7 shows these two parameters for a number of conventional and alternative fuels used in the marine sector. In the figure it can be seen that conventional diesel has a very beneficial combination of high gravimetric and high volumetric energy density, making the fuel type a difficult alternative to surpass in terms of energy density.

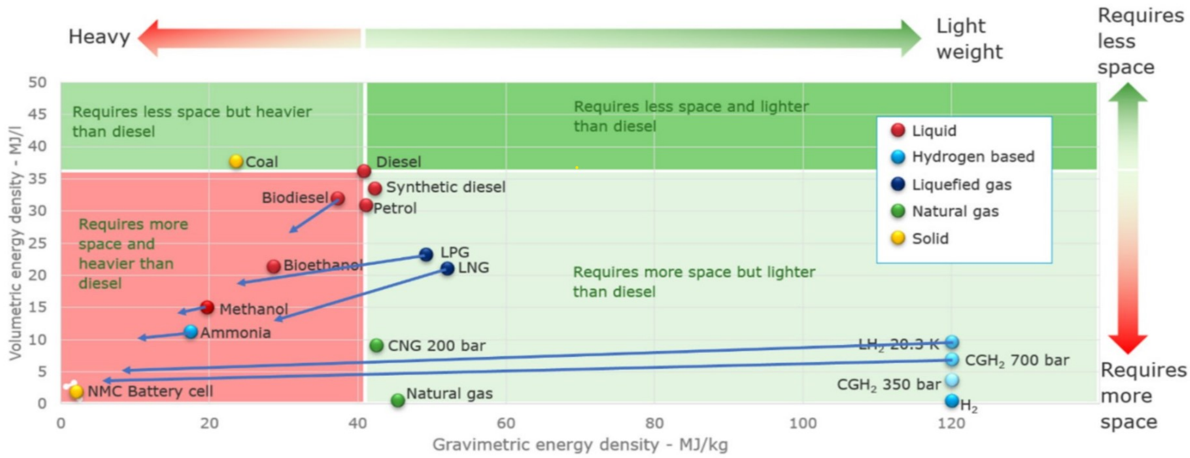


Figure 7: Volumetric and gravimetric energy densities for different energy carriers. The arrows indicate approximately how the energy density is affected when storage systems for each fuel type are included in the comparison. Figure source: DNV GL (2019b)

Ammonia, NH_3, is a substance used widely in industrial applications. It is most prominently used as a fertilizer in the agricultural sector. Ammonia is usually produced by utilizing the Haber-Bosch process, where hydrogen gas, H_2, and nitrogen gas, N_2, react with a metal catalyst under high pressure and temperature, which forms the compound NH_3. The chemical properties of ammonia makes the substance a good candidate for use as an energy carrier in the transportation sector. As the production of ammonia requires H_2, it is essential that this resource is derived from renewable production pathways in order for the fuel to be considered an environmental option. Nitrogen gas can be obtained from the atmosphere via air separation. In terms of energy losses, the efficiency of the whole production chain from electricity to ammonia amounts to approximately 52%. Ammonia is in a gaseous state under normal conditions, but by applying moderate pressure (> 8.6 bar) the substance can be handled as a liquid at room temperature. Ammonia is a highly toxic substance than can cause permanent injuries or death if one is exposed to it. This toxicity means that safety measures are essential to ensure the protection of crewmen and passengers onboard vessels that carry ammonia. In 2018, the global production of ammonia amounted to 170 million tonnes, of which practically 100% was produced using hydrogen from fossil sources. As the substance is already handled in such large quantities globally, there is existing infrastructure and industrial knowledge which could facilitate an expanding use of ammonia as a ship fuel (DNV GL 2020).

Methanol, CH_3OH, is a small and simple hydrocarbon alcohol. It is a commonly used substance that is found in many chemical processes and products, and it is also used as a transportation fuel. Methanol can be produced in several ways, utilising either fossil or renewable feedstock. Renewable methanol production can be carried out through two general pathways, either by processing biomass, which yields so called "bio-methanol", or by utilizing renewable electricity and captured CO_2 which yields so called "e-methanol". Bio-methanol is produced by fermenting or gasifying biomass, which can then be further processed in a reactor to form methanol. E-methanol is made by utilizing renewable electricity to produce H_2 trough water electrolysis, capturing CO_2 from the atmosphere or industrial exhausts, and then making these substances react to form methanol. The power to e-methanol efficiency is approximately 50% (Bos, Kersten, and Brilman 2020). Methanol is a liquid between the temperatures -93° C and +65° C (DNV GL 2019a), meaning it does not require pressurized or cryogenic storage tanks. Global demand in 2016 amounted to approximately 80 million tonnes (ibid.).

There are also several biofuels that could be suitable for use in the marine sector, such as hydrogenated vegetable oil (HVO), fatty acid methyl ester (FAME), and liquefied biogas. Generally, these fuels are produced by processing biomass in a reactor to form high quality fuels. These fuels do not emit fossil CO_2 when combusted, but they do emit biogenic CO_2, which can be seen as carbon-neutral. There is some controversy concerning the consequences of using biofuels, such as effects on biodiversity, how to view the biogenic CO_2 emissions, changes in land use and socio-economic effects. There are also questions regarding to what extent biofuels would be able to replace fossil fuels, in terms of quantity. In a net-zero emissions scenario for 2050 formed by the IEA (2021c), biofuels amount to 14% of global transport fuel supply, while hydrogen based fuels amount to 28% of transport energy requirements.

LNG and LPG are fuels mainly produced from fossil resources. LNG consists mainly of methane, CH_4, while LPG consists mainly of a mixture of propane, C_3H_8, and butane C_4H_{10}. These fuels are commonly suggested as suitable alternatives to conventional fuels used in the marine industry, as they perform better in terms of environmental impact (with regards to sulfur and CO_2 emissions) compared to dirtier marine fuel oils. Due to their fossil origin, these fuels will however not be further evaluated in this report, in order to remain within the scope.

Figure 8 below shows estimated fuel costs for various energy carriers through two energy conversion machines (ICE or fuel cell) in marine applications. This is presented as the cost per energy output of the system by applying a conversion factor onto the price per MWh of each fuel for each respective energy conversion machine. These costs do not include the cost of the ICE or fuel cell itself. It can be seen in the figure that the price range for hydrogen has the highest maximum values, but that they also have the largest price span. According to the figure, H_2 fuel cell conversion has a lower costs than H_2 ICE conversion. Battery-electric systems also have a large cost span, ranging from approximately 30 to 380 USD/MWh shaft output. The cost estimations for the conversions included in the figure are highly dependent on how the production pathway is designed and on price variations in the energy market.

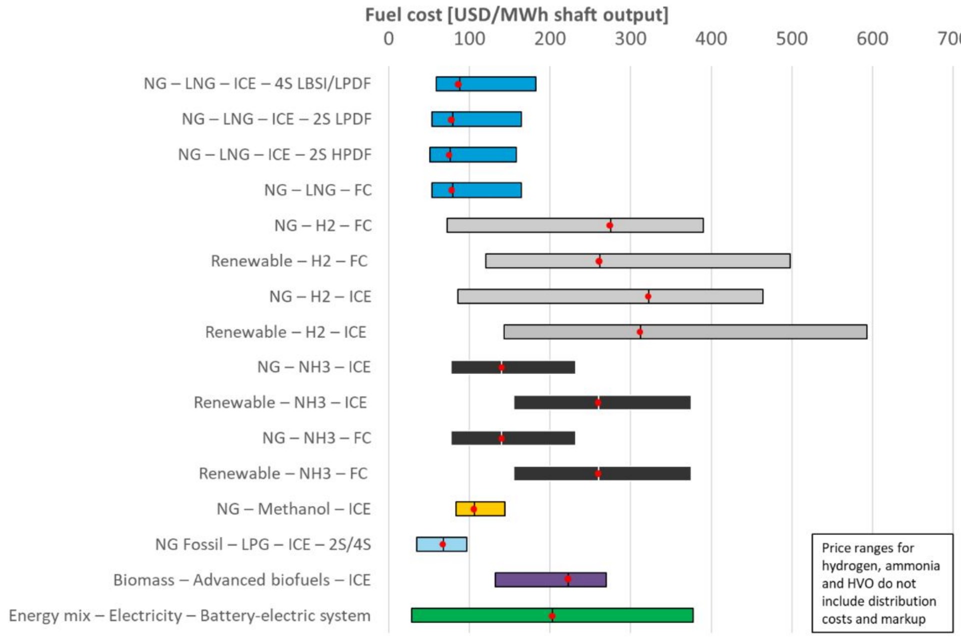


Figure 8: Fuel costs for various energy carriers in marine applications.

NG = Natural Gas (fossil origin). LNG = Liquefied Natural Gas. ICE = Internal Combustion Engine. 2S = 2-stroke. 4S = 4-stroke. LBSI = Lean Burn Spark Ignition. LPDF = Low Pressure Dual Fuel. FC = Fuel Cell. H2 = Hydrogen. NH3 = Ammonia. NG Fossil = Natural Gas with a mix of fossil origins. Figure source: DNV GL (2019b)

3.7 Charging buoys

Charging buoys are anchored floating mooring points and charging stations for service vessels. These components are still in a development stage with prototypes currently underway, and as such specific information is limited. During idle operation, vessels may connect to a buoy and all required energy can be received via the buoy either from the wind power park or the grid during this time (Stillstrom 2022). Charging buoy is also denoted as E-buoy, as abbreviated from electric charging buoy, henceforth in this report.

4 Method

The method to find answers to the posed research questions consists of four distinct parts. Firstly a literature study was conducted with the aim of obtaining technical specifications and emissions data for the year 2030 for the hydrogen and battery components covered above, and also to gain a deeper and more integrated understanding of the many topics at hand. Secondly a range of scenarios for the specific site were considered, generating a tree of cases for further evaluation. Thirdly, a dimension-, cost-, and emissions model was constructed in Microsoft Excel for evaluation of the relevant cases. This model was accompanied by an electricity price analysis, examining the historical spot prices in the NO2 area. Lastly a sensitivity analyses was carried out using the above mentioned model.

4.1 Literature Study

The literature study consisted of firstly examining both the current and future costs and characteristics of the components needed, using the former as a reference point and focusing on the latter. The literature study also served as a tool to validate the chosen methodology, examining and comparing similar studies. Next, life cycle emissions were examined, focusing on LCA reports where possible. Off all examined sources, a total of 38 sources on costs and characteristics, and 12 on life cycle emissions - out of which one overlapping - were included in the data-set used. Sources included articles, books, industry reports, government reports, and manufacturer data-sheets. Throughout the literature study, attention was payed to map component suppliers with potential synergies with Norwegian industry.

4.2 Determination of Cases

Due to the many parameters involved in the project, a limitation was made to only investigate the most relevant, plausible and interesting cases. The determination of these cases was carried out in dialogue with project representatives within RWE Renewables, in order to find the most realistic scenarios for the Utsira Nord wind farm. Four key parameters could be identified to be of importance for the system design. These main parameters are as follows; vessel type, harbour location, availability of offshore charging, and vessel drive train. To narrow down the number of possible combinations the following delimitation were made: Only two harbour alternatives were examined - Utsira and Haugesund - although there could be other feasible alternatives. Another delimitation was made in assuming a work cycle of two weeks for all SOV cases, though in theory this could be anything from one week to a full month. Conventional diesel ICE vessels were included among cases to examine, as base case scenarios to compare costs and emissions. The determination of cases was also carried out by performing a technical analysis where the carrying capacities of the vessels, in terms of mass and volume, was compared to the required mass and volume of the examined on-board energy storage. Selection of technical components, such as electrolyser type, storage tank types, drive train technology etc. was made based on findings in the literature study. Technological maturity and cost efficiency were deemed as key aspects in the selection of technology.

4.3 Modeling of Dimensions, Costs, and Emissions

4.3.1 Modeling of Dimensions

Model basis
The dimension-, cost-, and emissions model, hereafter simply referred to as the model, contains all the assumptions made based on the literature study, and has its outset in the engine power and energy consumption of conventional service vessel designs - which are assumed to operate at a capacity factor (CF) of 70% with 4-stroke engines (see Appendix). These vessels can then be said to be redesigned with alternative drive trains and energy storage systems, proportionate to the originals. The CTV cases derive their energy requirements bases on MFO fuel consumption, but CTV base cases are therafter treated as if the corresponding energy would be supplied by MGO, to comply with SECA regulations. The components, together with the associated fuel production and storage (in the case of hydrogen as fuel) are then dimensioned based on distances and operating patterns, whereafter the cost of fuel and operational cost of the vessels are determined. The model also contains parameters for equipment capacity factors, redundancy scaling, electricity mix, drive train hybridisation, etc, allowing for the generation of many variable sub-cases. The model includes information regarding hourly variations in electricity spot price data which makes it possible to optimise cases after the hours when electricity prices are lowest. It should be noted that the model only considers the drive train, energy storage, and fuel costs, and no other aspects of the vessel, such as hull construction or accommodation, as these are assumed to remain the same as for conventional vessels.

Battery drive train hybridisation
As input data regarding fuel consumption for SOVs is based on an an ICE-battery hybrid reference vessel - with increased fuel efficiency - all SOV base cases are built with a minimum battery capacity equal to the reference. Battery hybridisation is considered the norm for future drive trains due to energy efficiency improvements, and as such all other cases (both SOV and CTV) are also constructed with a small amount of installed battery capacity, equal to their respective hybrid reference vessel (500 kWh for SOVs and 200 kWh for CTVs). Therefore all cases will derive some energy directly either from the park or the grid.

Electric power input
The electric power which supplies the fuel production and/or battery charging is derived either from the park, the grid, or a combination thereof. The factor determining the ratio of park to grid electricity supply per case is determined based on the location of power consumption and the substation meter. Assuming a perspective of energy flow originating from the park, any power taken in the park is defined as "before" the meter, power taken on the main-land is defined as "after" the meter, and power taken by the assumed place of the substation at Utsira Island, can be either. Before the meter equates to taking

power from the park, and after equates to the grid. Placing all components in Haugesund results in a factor of 0, and a placement of all components offshore results in a factor of 1. This factor determines which costs and emissions result from power consumption.

Impact of charging buoy
The inclusion of a charging buoy impacts several parameters of the model, but only for the SOV cases, as the available time for its use in the CTV cases is deemed limited. Firstly, the power factor discussed above is increased. Secondly, the loitering energy storage required is reduced by a factor of 0.5 in the hydrogen cases and by a factor of 0.9 in the full battery case. The logic being that for half of each day in the park (during night time) the vessel can be moored to the buoy and rely on its direct energy supply, cutting the energy storage needed in half. During this period the battery can also be recharged, leading to the recharge opportunity increasing from once every 14 days to once per day. For the full battery case, the loitering energy storage required could then in theory be reduced to $\frac{1}{2 \cdot 14} \approx 0.04$ of the original, or by a factor 1-0.04 = 0.96, and from there the slightly more conservative number of 0.9 is applied. This reduction in loitering energy lowers the scaling of fuel production and energy storage. Furthermore, the ability to moor and receive power from the buoy impacts the lifetime of the fuel cell and battery, as their operating hours are affected. The fuel cell must operate less, extending its lifetime. The battery is decreased in size and is more frequently cycled, shortening its lifetime. However, due to other uncertainties in battery lifetime, a fixed end of life is set instead, as explained in section 5.1.

Energy storage redundancy
In all cases, energy storage redundancy is included (meaning that more energy is stored on-board and in harbour than what is required) but the factor varies depending on the energy carrier. For hydrogen the factor is set to 1.3 on the ship side and 1.4 on the harbour side. For full battery vessels the factor is primarily set to 1.3 on the ship side when charging buoy is not included, but is lowered to 1.1 when charging buoy is included. The reasoning behind this is that less redundancy is needed when the possibility for continuous recharging is present. Furthermore, the loitering- and transit energy storage can act as supplementary redundancy for each other in this case, as both can be recharged in the park. The transit energy requirements are calculated for the round-trip between port and park, meaning that the vessels should always be able to return to port if malfunctions occur with the charging buoy.

Space requirements for hydrogen production
The space occupied by the production of hydrogen via electrolysis varies depending on installed electrolyser power and hydrogen storage capacity. However, the installed power capacity of the electrolyser of all cases fall within the same space span, as specified by manufacturers. Storage space varies as a function of kWh H2 storage, and is based on the stacking of 12 storage type I tanks to a height of 8.5 meters in all cases. This number was chosen as to not protrude the estimate height of a two story building.

4.3.2 Modeling of Costs

Net present cost calculations
The total cost of each system is expressed as the net present cost over the park lifetime. Capital expenditure (capex) of each component is based on their respective dimensions, and the operational expenditure (opex) is set as a yearly, static percentage of this capex. In this report, opex does not include power- and fuel expenditure, as these are categories of their own. Certain components have lifetimes shorter than the system lifetime, and in these cases a specific reinvestment capex is applied at the time(s) of their end of life. The end of life occurs at different times for different cases, as the operational pattern of the components differ from case to case. The components which require reinvestments are electrolyser, compressor, fuel cell, and battery (see Appendix). Initial capex is higher than reinvestment capex as to account for system installation costs and balance of plant components, with the exception of the compressor which is assumed as a single component. In the case of electrolyser- and fuel cell systems, only the stacks out of all the system component are replaced, and for the battery systems only the battery pack is replaced. The net present cost (NPC) is calculated as shown in equation 6 below.

$$NPC = C_0 + \sum_{i=1}^{n} \frac{C_i + O_i + F_i}{(1+r)^i} \tag{6}$$

Where C_0 is the sum of all initial capital cost, and C_i, O_i, and F_i is the capital cost, operational expenditure, and fuel expenditure of year i, respectively. Fuel expenditure in this case is the consumed diesel, electricity of the electrolyser and compressor, and the electricity for battery charging. Finally, n is the economic lifetime of the considered system which is set to 25 years, and r is the discount rate, set universally to 10%.

Cost of electricity
An analysis of electricity spot prices could be carried out thanks to availability of historical spot price data from Forbrukerrådet (2022). Spot price data from 1 January 2017 to 7 October 2022 was downloaded and could be analysed in Microsoft Excel. Data is only included until the 7th of October as this was the date when the price analysis in this report was commenced. The data was processed in order to obtain an understanding of how electricity prices have varied over the past five years and how they vary with the hours of the day. The average price for each hour of the day was used to create a price variation factor, i.e a factor which describes how the hourly price varies in relation to the average price of each day. This price variation factor could then be used in the model, making it possible to make cost optimizations where electricity is not used during the most expensive hours of each day. Using less hours per day means that components such as the electrolyser must have greater capacity, which the model accounts for by scaling these components based on how many hours per day they are intended to operate. The capex and opex of these components also scales based on their capacity. This spot price variation model is only used to calculate the prices for electricity purchased from the external grid, as a fixed price was used for the electricity taken from the internal grid of the wind farm.

Cost of hydrogen and MGO
The cost of fuel is determined either from external sources and calculations within the model, as is the case for electricity price, or via external sources and estimations alone, as is the case for MGO. As described above, no explicit hydrogen cost is used, but the cost of hydrogen is instead incorporated into the total via the cost of its constituent parts, i.e electrolyser, compressor, land storage and electricity consumption. However, to get a comparative number for the cost of hydrogen production, these same constituent parts are also used to calculate the levelized cost of energy (LCOE), using equation 7 below.

$$LCOE = \frac{C_0 + \sum_{i=1}^{n} \frac{C_i + O_i + F_i}{(1+r)^i}}{\sum_{i=1}^{n} \frac{E_i}{(1+r)^i}} \tag{7}$$

With the same variables as for equation 6 above, with the addition of E_i which is the energy produced (hydrogen) in year i.

4.3.3 Modeling of Emissions

The emissions from each respective case is reported as GWP_{100} in g CO_2-eq. As far as possible, this modeling is based on emissions over the whole life cycle of each component and energy source. Out of all investigated components, only the compressor and the charging buoy were left unaccounted for due to limited data. The base cases are calculated via a single number of life cycle emissions per kWh of MGO use. The hydrogen cases are constructed by incorporating emissions from park- and grid electricity, electrolyser, type I and type IV storage tanks, and fuel cell. The battery case incorporates emissions from the electricity from park and grid, as well as from the battery. In all cases where replacement components are required due to limited technical lifespans, the emissions of replacement components are accounted for. For more exact descriptions of emission contributions, see section 5.1. Emissions are then calculated as CO_2-eq/year and also as total CO_2-eq reduction compared to the base case over the lifetime per increase in net present cost.

4.4 Sensitivity Analysis

A sensitivity analysis was carried out where uncertainties in the results were analysed. There were many factors in the calculations that could cause inaccuracies in the results, many stemming from variations in values found in the literature study.

An comparative sensitivity analysis was carried out where the differences in capex values found in the literature were examined. Firstly, two scenarios were constructed; all capex values set to the lowest values found in literature, and all capex values set to the highest values found in literature. Under these conditions, the NPCs for all cases were recalculated yielding an optimistic scenario and a pessimistic scenario. Furthermore, the high uncertainty in the charging buoy capex was analysed in a separate scenario, and so was the sole impact of increased MGO prices. The approach for this was to alter these parameters until the relationships between NPCs for different cases changed noticably or until cost parity was reached. For example, investigating how high the MGO price had to be for base-cases to become more expensive than hydrogen-cases. The parameters were iteratively increased (respectively) until a base-case surpassed a hydrogen case in terms of NPC, and until the hydrogen case with a charging buoy surpassed the case without charging buoy in NPC.

A global parameter sensitivity analysis was also carried out on input values which affect all or most cases simultaneously. The effects of changes in electricity price in the NO2 area were examined. One higher price was set to the highest annual average price found in the historical spot price analysis (see figure 14), and one lower price was set to 50% of the price predicted for 2030 by Statnett (2021). The vessel energy requirements were also examined to see what effect variations in these values would have on the results. These parameters were chosen as there could be large differences in the operational pattern of vessels with different crew and routines, and as there are some uncertainties regarding the fuel consumption for different procedures during a wind farm service excursion. The vessel fuel consumption was increased and decreased by ±50% to see what effect this would have on NPC.

Finally, a sensitivity analysis on the impact of calculation method on emissions was carried out. Here, a comparison was made between the report standard - the life cycle approach - and an end-of-pipe emissions approach.

5 Results and Analysis

5.1 Literature Study

The results from the literature study are presented below. All final values chosen for this report on costs, characteristics, emissions, etc, are compiled in the Appendix.

5.1.1 Component Costs and Characteristics

In regards to component costs and technical characteristics, the findings for the former were of high variance whereas the findings for the latter were of low variance. Figure 9 below shows a representation of future capital expenditure values found. Future cost predictions were not found for compression, hydrogen storage type I and IV, System borders were not always clearly defined, but a distinction between "system cost" and "component cost" was commonly reported. Higher cost were often reported for marine application as compared to non-marine application, with special integration costs (safety, monitoring, and control) stated as motivation. As mentioned, a higher degree of consensus was found regarding component specifications, such as efficiencies and storage energy densities, but lifetime expectancy and electrolysis space requirement values varied. Component lifetimes both longer and shorter than the system lifetime were found for PEMEC, AEC, PEMFC, and ICE. Battery lifetime was defined in many different ways, including operation hours, number of cycles, and years. If the number of cycles and the DOD were to determine the lifetime according to equation 5, then the battery would outlast the system lifetime in the examined SOV battery case. However, due to external factors and natural aging of batteries, a more conservative lifetime of a set 15 years was applied. Space requirements for electrolysis varied by a factor of 10 when comparing manufacturer datasheets with studies of implemented systems (Danish Energy Agency 2017), which might depend on varying system boundaries.

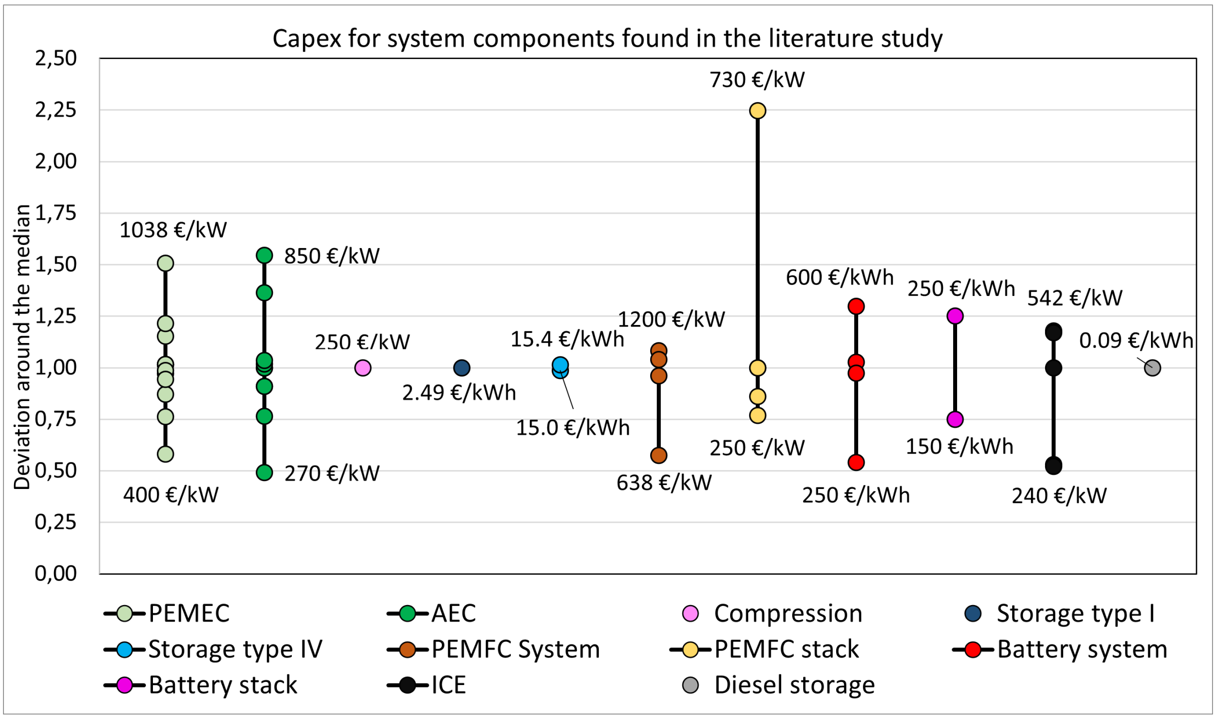


Figure 9: Literature study values, normalized around the median, of capital expenditure of the chosen technologies.

Each dot represents a value derived from the literature study, and the lines indicate the span of values for each component. The absolute values of each maximum and minimum are also shown in text in the diagram. Unit explanation: The capex of electrolysers is per kW input, compression is per kW H2 output, energy storage is per kWh capacity, fuel cell and ICE is per kW output. For ICE, the lower value corresponds to 4-stroke and others to 2-stroke. Sources are listed in Appendix.

5.1.2 Norwegian Manufacturers

Several Norwegian companies that develop technology relevant to this project were found during the literature study. Among these are the companies NEL Hydrogen, HydrogenPro, Corvus Energy and Ulstein Group. There may also be other companies in Norway working in these areas, a full market analysis has not been performed.

NEL Hydrogen is a company that delivers solutions for production, storage and distribution of hydrogen (NEL Hydrogen 2022). Their products include PEM electrolysers, alkaline electrolysers, hydrogen storage tanks and fuelling stations. Their corporate headquarters is located in Oslo, Norway.

HydrogenPro is a company that delivers hydrogen production solutions (Hydrogen Pro 2022). Their core product is a high pressure alkaline electrolyser. Their headquarters is located in Porsgrunn, Norway.

Corvus Energy is a company specialized in providing battery solutions for maritime applications. The company has supplied battery solutions (hybrid solutions mainly) to a range of ships, including offshore support vessels, construction vessels, ferries, etc. (Corvus Energy 2020). Their head office is located in Bergen, Norway.

Ulstein Group is a company that is specialized in ship design solutions, shipbuilding and shipping. Among other things, they design and build vessels for the offshore industry. They currently have hydrogen fuel cell offshore service vessels under development, which could be ready for deployment in the near future (Ulstein 2021). Their head office is located in Ulsteinvik, Norway.

5.1.3 Life Cycle Emissions

Below, the findings on life cycle emission contributions from energy supply and the different components are presented.

GWP from electric power
The life cycle GWP of floating offshore wind power with conventional O&M vessels was set to 27 g CO_2-eq/kWh of produced energy, based on median values of the literature study conducted by Garcia-Teruel et al. (2022). The value used in calculations in this report is then defined as 70% of this number, as an estimate 30% of lifetime GWP was found to stem from fossil powered O&M vessels (ibid.), which are now assumed as decarbonized, resulting in a GWP from the offshore wind power park at 18.9 g CO_2-eq/kWh. For electricity taken from the Norwegian grid, a GWP intensity of 25 g CO_2-eq/kWh is used (Our World in Data 2021).

GWP from hydrogen production
The GWP associated with hydrogen produced via electrolysis from wind power was found to stem to around 95% from the wind power itself (Delpierre et al. 2021). This study determined the contribution from wind power to make out 21 g CO_2-eq/kWh H2 and the remaining 5% from electrolysis constituting only 1 g CO_2-eq/kWh H2. This approximate GWP contribution from electrolysis is supported in the review by Bhandari, Trudewind, and Zapp (2014), which reports a 4% contribution from electrolysis at 1.17 g CO_2-eq/kWh H2. In a report by DNV GL (2019a), on alternative fuels in the maritime sector, the number for the total GWP of hydrogen is reported at below 8 g CO_2-eq/kWh H2. Due to these conflicting numbers, a specific calculation is chosen for the GWP of hydrogen production in this report. First, the set GWP per kWh power from the park and the grid used for electrolysis and compression is considered (including losses), upon this another single unit is added per kWh hydrogen output such that hydrogen production has a GWP of 30.4 and 39.9 g CO_2-eq/kWh H2 when produced from the park and the grid, respectively.

GWP from hydrogen storage and utilization
Upon the values presented above, the contribution from storage and utilization must also be incorporated into the total GWP of hydrogen systems. The level of storage per utilized kWh of hydrogen may differ greatly from case to case, and as such the decision was made to calculate this on a case basis as well. Storage may come in two forms, type I or type IV (types II and III are not used). For type I storage, GWP is calculated based on material mass, as no direct LCA data was found for this type of storage. From a weight to weight ratio between hydrogen and tank of 1.7 wt% (Rivard, Trudeau, and Zaghib 2019b), and a steel production GWP of 1700 g CO_2-eq/kg steel (Suer, Traverso, and Jäger 2022), as well as an energy content of hydrogen at 33.3 kWh/kg (Møller et al. 2017), the resulting GWP becomes 3000 g CO_2-eq/kWh hydrogen storage capacity. For type IV storage, the corresponding number is 12000 g CO_2-eq/kWh (Usai et al. 2021). From the fuel cell (PEMFC), 31000 g CO_2-eq/kW of installed power is added, along with an additional 22000 g CO_2-eq/kW of stack replacements at the end of the lifetime (ibid.).

GWP from battery storage
The GWP from batteries is retrieved from sources within the automotive industry, as sources on batteries for strict application within the maritime sector are scarce. Two LCA studies of complete battery packs were considered. Interpreted data from Mats Zackrisson (2017) and from Lisa Bolin (2020) yields a GWP of 92400 and 89700 g CO_2-eq/kWh storage capacity, respectively. Of these, the former value is used in this report, as input variables and battery specifications were more thoroughly reported and could be validated against values and assumptions in this report. The chosen GWP-value assumes a Swedish electricity mix used for battery assembly.

GWP from conventional fossil fuel powered systems
Varying values were found for the GWP of conventional fossil fuel MGO systems - one at 309 (DNV GL 2019a) and one at 322 g CO_2-eq/kWh fuel input (Lindstad et al. 2020) (derived from calculations of 685 g CO_2-eq/kWh output at an engine efficiency of 0.47). The latter of these values was chosen for this report due to more explicitly reported calculations. Lindstad et al. (ibid.) also reports a well-to-tank GWP of 54 g CO_2-eq/kWh fuel, i.e. the emissions associated with the life cycle before combustion (life cycle including combustion is denoted well-to-wake). When subtracting the well-to-tank value from the full life cycle, one derives emissions associated with only combustion at 268 g CO_2-eq / kWh of fuel.

5.2 Determination of Cases

5.2.1 Technology Selection for Production, Storage and Drive-trains

It was chosen that all electricity needed for hydrogen production and battery charging in harbour should be purchased from the regional grid. This is due to the estimations of electricity price (explained more thoroughly in section 5.3.2) which indicate that it will likely be more costly to utilize self-produced power from the wind farm than to purchase power from the grid. Further, there is a large uncertainty concerning the cable route from the wind farm to grid connection point and if it will pass through Haugesund or not, which would be critical in order to utilize self-produced electricity in harbour.

Regarding electrolysers, both AEC and PEMEC were investigated in the analysis. The electrolyser type which showed the best economic performance was the AEC. Both electrolysers were analysed together with the price optimisation feature, which showed that the cost optimum operational time was 19 hours per day for AEC and 24 hours per day for PEMEC. The difference in these values is due to the higher capex for PEMEC in comparison to AEC, making them more costly when needing greater installed capacity. The result that PEMEC has an optimum operating time of 24 hours per day means that it is not cost effective to install a larger electrolyser that runs on low price-hours, under the given circumstances. AEC is more cost efficient even with no hourly price optimization, in comparison to PEMEC. For the case with electrolyser on board the ship, PEMEC was chosen in order to minimize the time required for initiating electrolysis, as it will start and stop more often than the stationary AEC.

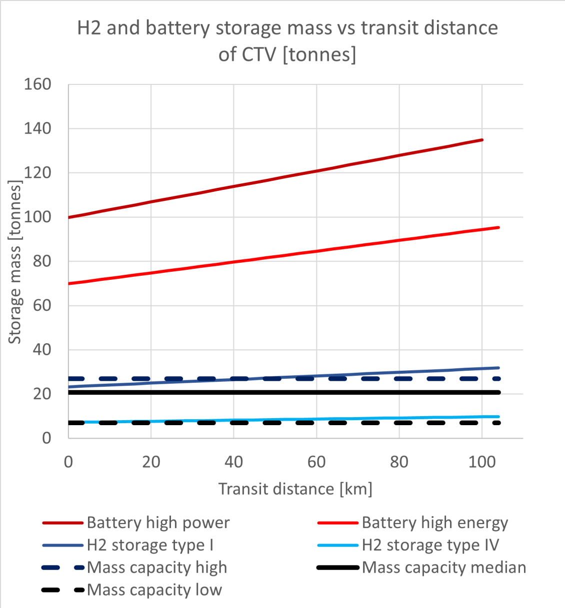
Type I storage tanks were selected for on-land storage due to their low costs and sufficient pressure capabilities. Geological storage was not considered, due to many uncertainties regarding placement of the hydrogen production facility and fuelling station. Type IV tanks were examined for the on-board storage due to their weight efficient qualities. Type I tanks were also examined for on-board storage of SOVs, despite their greater weight, due to the very high carrying capacities of SOVs.

PEM fuel cells were selected for the on-board energy conversion process, as the technology is in a relatively mature state and due to the efficiency of the energy conversion. Li-ion battery propulsion systems, including electric motors, were also examined in the analysis due to their technical maturity and potential suitability for the project. The required propeller output power of the vessels was set to 1800 kW for the CTVs and 7800 kW for the SOVs, based on median values for each vessel type examined in the literature study.

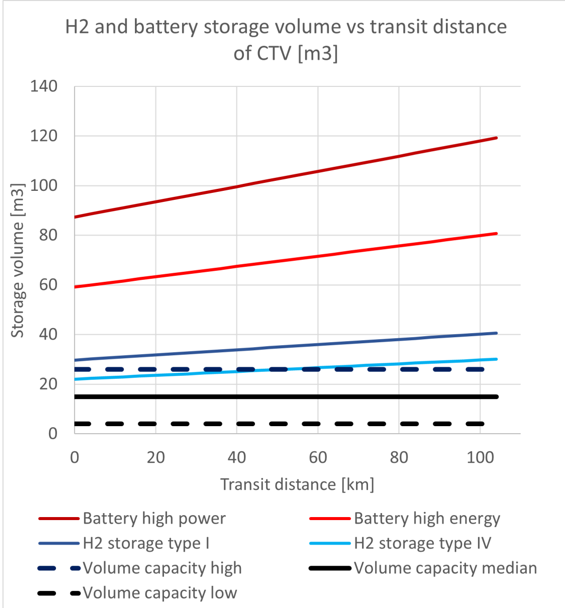
Offshore charging buoys were included in the analysis, due to their potential to reduce the on-board fuel storage requirements. The buoys were only analysed in combination with SOV-cases, as it was deemed unlikely that CTVs would have the time or need during a workday to connect to a charging buoy.

5.2.2 Analysis of Vessel Carrying Capacities

An analysis was carried out which gave insight into which energy storage options were viable in terms of vessel carrying capacities. Vessel capacities are derived from the examination of 13 CTV- and 8 SOV datasheets. It was seen that CGH2 together with PEMFC was a possible solution for all vessel types and considered distances, and that full battery options were non-viable for CTVs but viable for SOVs when combined with a charging buoy, in regards to mass and space requirements. Figures 10 and 11 below show these relations as a function of transit distance to the park. Note that the mass and volume of storage is not zero at a transit distance of zero, as the storage for the remaining time in the park after transit is also included in the figures.



(a)



(b)

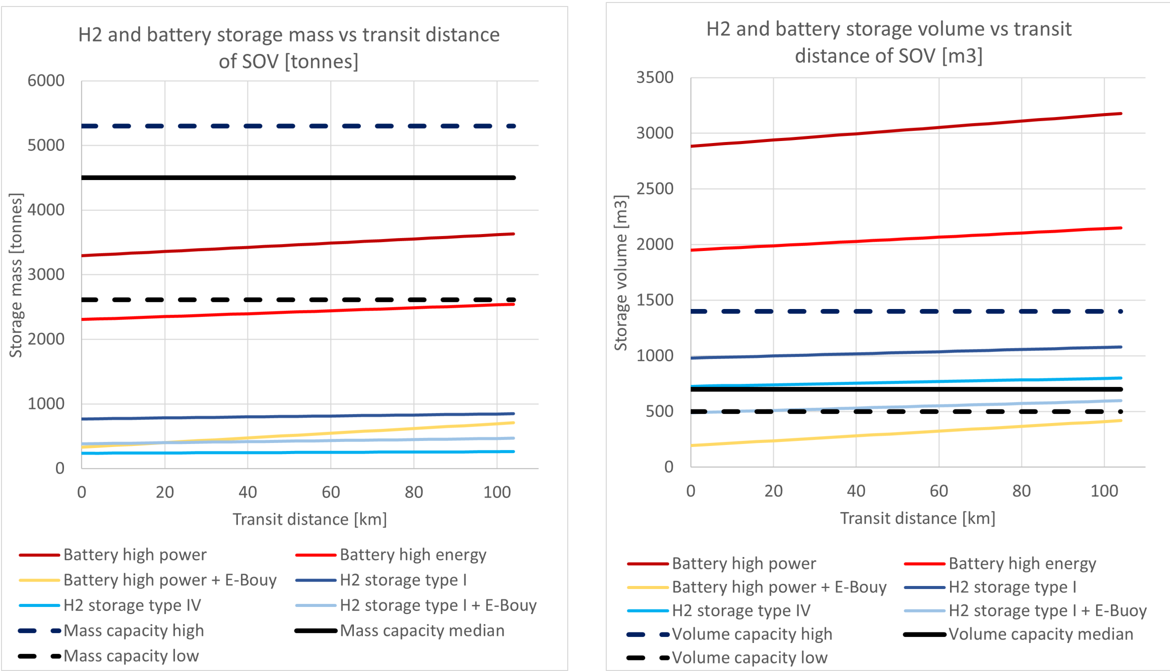
Figure 10: CTV carrying capacity and energy storage mass and weight.

Shows how the mass (a) and volume (b) of H2 and battery storage on a CTV increases with transit distance to the park, together with vessel capacity median-, high-, and low values. The mass capacity is the combined mass of the filled conventional fuel tank and cargo capacity. The volume capacity is the volume of the conventional fuel tank, not including potential on-deck extensions. Both figures also include the storage required for the remaining in field loitering after transit (which decreases with increasing transit distance). Battery high power and high energy correlate to different battery configurations. The figures include storage redundancy.

As seen in figure 10a, the mass of hydrogen storage type I lies on the border or above the capacity of the CTV for ranges longer than 40 km, whereas the mass of type IV falls below the capacity of the CTV for the entire range span with the exception for vessels with the lowest of capacity. In figure 10b, it is seen that the volume of the storage type I lies above the CTV capacity for the entire span, and type IV also exceeds the span for distances longer than about 40 km. The CTV could thus need extra storage capacity, e.g., on deck, but the extra volume necessary is deemed within reasonable limits.

Full battery solutions were ruled out for CTVs for all distances as the mass of the batteries needed to cover solely the loitering time in the park already exceeded the capacity of the vessel for both the high power and high energy configurations, and with added transit distance the battery mass increases further, as seen in figure 10a. The volume of the battery also exceeds the capacity of the vessel regardless of configuration, as seen in figure 10b.

For the SOV cases is was seen that both CGH2 together with PEMFC, as well as full battery solutions when combined with a charging buoy, were viable in regards to mass and space requirements as depicted in figure 11 below.



(a) (b)

Figure 11: SOV carrying capacity and energy storage mass and weight.

Shows how the mass (a) and volume (b) of H2 and battery storage on an SOV increases with transit distance to the park, together with vessel capacity median-, high-, and low values. The mass capacity is the deadweight tonnage, i.e. the maximum allowable loading. The volume capacity is the volume of the conventional fuel tank, not including potential on-deck extensions. Both figures also include the storage required for the remaining in field loitering after transit (which decreases with increasing transit distance). Battery high power and high energy correlate to different battery configurations. The figures include fuel storage redundancy.

The required mass of H2 storage for both type I and IV falls well below the capacity of the vessels, and the required , especially when a charging buoy is included, as seen in figures 11a and 11b respectively.

The mass of both battery configurations falls within permissible spans but the volume exceeds the capacity of the vessel when no charging buoy is included in the scenario, as seen in figures 11a and 11b respectively. With a charging buoy present however, the needed storage volume falls below even the lower of capacities as seen in figure 11b.

5.2.3 Resulting Cases

The delimitations made in order to examine the most viable options for the Utsira Nord wind farm specifically, in combination with the selection of most suitable technology for the application, along with the analysis of carrying capacities, resulted in 10 scenarios that would be further evaluated. Figure 12 shows the resulting scenarios and the four key parameters that set them apart. Four of these scenarios are fossil fuel solutions, out of which three are solely included as base case scenarios against which to compare the renewable alternatives.

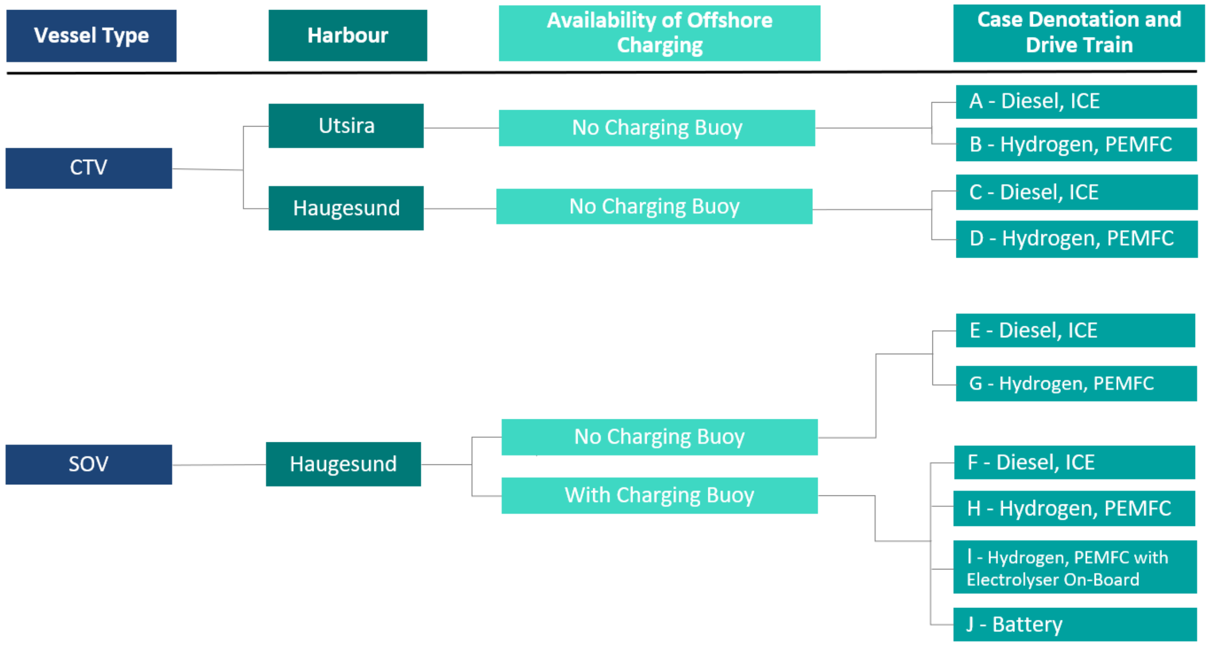


Figure 12: Tree diagram of cases included in analysis.

The cases with diesel drive trains are solely included as reference scenarios against which to compare the renewable alternatives. Note cases F and G which appear alphabetically in reverse order.

5.3 Electricity Price

5.3.1 Historical Price Analysis

Norwegian electricity prices in the NO2 area could be analyzed thanks to historical spot price data (Forbrukerrådet 2022) and day ahead market data (Nord Pool AS 2022). Two data sets were used for this analysis, as the spot market data could be analyzed with greater resolution (hourly values for the past five years), and as the day-ahead market data could provide insight further back in time (yearly average values available from 2002-today). The analysis showed that electricity prices have increased significantly during the years 2021 and 2022. The spot market data showed that fluctuations in electricity price have increased significantly as well during the same time period, with greater amplitude in price variations. A cyclical pattern of lower electricity prices during weekends could be identified. A visualization of the average spot price per day for the past five years is presented in figure 13.

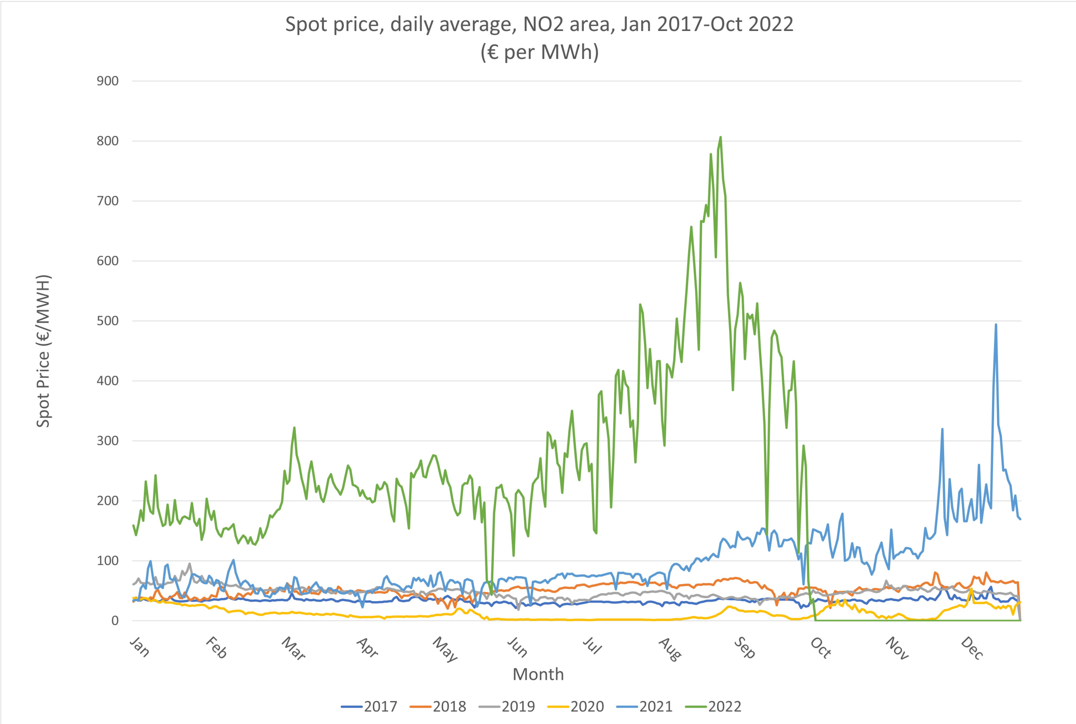


Figure 13: Daily average spot price for the NO2 area, for the years 2017-2022.

Data for 2022 is only included until the 7th of October. Data source: Forbrukerrådet (2022).

The day-ahead market data is visualized in figure 14. In this figure it can be seen that the electricity prices have been very low the the past two decades, with an average price in the years 2002-2020 of approximately 33 €/MWh. In 2022 (January 1 - October 31) the average price has increased by a factor of six, to 216 €/MWh.

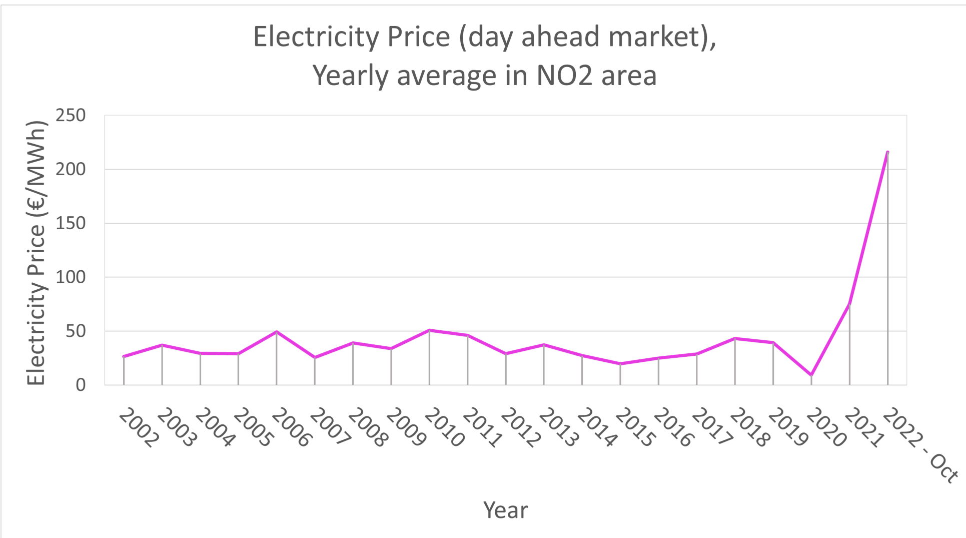


Figure 14: Yearly average electricity prices for the NO2 area on the day ahead market, for the years 2002-2022.

Prices are given in € per MWh. Data for 2022 is based on prices from January 1st until October 31st. Data source: Nord Pool AS (2022).

An analysis of how electricity prices vary for each hour of the day was also performed, which showed that prices are highest in the hours around 08-09 in the morning and at 19-20 in the evening. This trend is found in all years included in the analysis. Based on this, a feature was added to the economics model which varies the electricity price used in the calculations, based on how many hours per day the electrolyser is designed to run. Choosing less hours of operating time per day means that the cheapest hours of the day can be utilized for hydrogen production, but it also requires greater electrolyser power which is associated with greater capital expenditure. The hourly price optimization was not implemented for the battery charging scenarios, as the times when the battery-vessels can be charged is less flexible and charging can only be carried out when the vessels are in port. As the time spent in port is dependent on several factors such as weather and maintenance schedules, it is more difficult to predict than an electrolyser which will remain in port throughout all hours of the day. A visualization of the average spot price for each hour of the day is presented in figure 13.

Spot price, average per hour of day, NO2 area, 2017-2022 (€/MWh)

Time	2017	2018	2019	2020	2021	2022	Average	Variation Factor (unitless)
00-01	31.4	47.5	43.3	10.9	85.3	270.5	81.5	0.963
01-02	30.6	46.0	42.2	10.6	83.2	256.7	78.2	0.925
02-03	30.1	45.1	41.4	10.4	81.1	248.5	76.1	0.899
03-04	29.9	44.9	41.2	10.3	79.9	242.8	74.8	0.884
04-05	30.0	45.1	41.5	10.5	81.0	242.2	75.1	0.887
05-06	30.9	47.5	43.4	11.0	83.9	252.9	78.3	0.925
06-07	32.2	50.6	45.8	11.5	88.7	267.8	82.8	0.978
07-08	33.9	54.6	47.8	12.3	95.9	291.8	89.4	1.056
08-09	34.8	56.8	49.1	13.1	103.3	305.5	93.7	1.108
09-10	34.6	56.4	49.0	13.0	103.1	293.9	91.6	1.083
10-11	34.2	55.6	48.7	13.0	99.4	281.2	88.7	1.048
11-12	33.9	54.6	48.3	12.7	97.2	268.8	85.9	1.015
12-13	33.6	53.6	47.8	12.7	94.9	256.0	83.1	0.982
13-14	33.3	52.9	47.5	12.6	92.9	245.8	80.8	0.955
14-15	33.1	52.3	47.1	12.1	92.3	239.5	79.4	0.938
15-16	33.2	52.4	47.1	12.4	93.7	246.2	80.8	0.955
16-17	33.7	53.0	47.5	12.6	97.5	259.6	84.0	0.992
17-18	34.4	54.7	48.3	12.9	102.3	279.3	88.6	1.047
18-19	34.3	55.7	48.7	12.6	104.2	298.8	92.4	1.092
19-20	33.8	54.6	48.6	12.5	101.1	309.1	93.3	1.102
20-21	33.3	52.9	48.0	12.2	96.6	309.4	92.1	1.088
21-22	33.0	51.8	47.1	12.0	93.2	303.2	90.0	1.064
22-23	32.4	50.3	46.0	11.6	90.9	293.1	87.4	1.033
23-24	31.5	47.9	44.2	11.1	86.3	276.3	82.9	0.979
Average	32.7	51.5	46.2	11.9	92.8	272.5	84.6	1.000

Figure 15: Hourly average spot prices for the NO2 area for the years 2017-2022

Prices given in € per kWh. The column to the far right contains a price variation factor, i.e. a factor which describes the average hourly deviation from the average daily spot price. The color gradient indicates relative price differences in each column: green corresponds to lower price and red corresponds to higher price. Data for 2022 is only included until the 7th of October. Data source: Forbrukerrådet (2022).

The results from this hourly price analysis is that an economically optimal electrolyser run time per day could be determined for all cases that require hydrogen production in port. The optimum run time was determined to 19 hours per day, for alkaline electrolysers. This result is based on the capital expenditure for the electrolyser (which increases with the greater electrolyser capacity requirements when decreasing the run time), and the present value of the electricity cost for the lifetime of the system. Utilizing the electrolyser during the 19 cheapest average e-price hours per day means that the electrolyser will be inactive between the hours 08:00-10:00 and 18:00-21:00. For PEM electrolysers, it was found that it was not economically beneficial to install a greater electrolyser capacity in order to utilize cheaper e-price hours, the lowest costs were found for run times of 24 hours.

5.3.2 Future Price Predictions

Two key figures for electricity pricing required for cost calculations could be determined. The two prices needed for calculations were the price for purchasing electricity from the Norwegian grid as well as the cost for taking power directly from the wind farm.

A long term power market analysis from Norwegian transmission system operator Statnett was found which provided insight into possible future electricity prices in southern Norway. The publication presents simulated electricity prices in 2030, with regards to inflation and market development. The price simulated for southern Norway in 2030 amounts to approximately 48 € per MWh (Statnett 2021). In the same publication, several price scenarios stretching towards 2050 are also presented. The prices in these scenarios indicate price increases and decreases of ±7 € per MWh relative to the simulated price for 2030. This uncertainty gave reason to assume the same e-price for all years included in analysis.

Norwegian tax rates were examined to find the electrical power tax rate which applies for the purposes examined in this report. A tax rate of 5.46 € per MWh applies for electricity used for ships in industry (The Norwegian Tax Administration 2022), this tax rate was assumed to apply for the scenarios at hand. A further assumption was made that this tax rate would remain the same for all years included in the analysis.

The base electricity price of 48 € per MWh, together with the power tax, was used in all calculations involving purchase of electricity from the grid. The hourly price optimisation was used for cases where hydrogen production occurs in harbour. Using the hourly price optimization feature, with an optimal electrolyser run time of 19 hours per day (for AEC), the purchase price amounts to 47.35 € per MWh, including taxes. When excluding the hourly price optimisation, the total purchase price is 48.55 € per MWh.

The cost of taking power from the wind farm was based on LCOE estimates for floating wind farms, assuming that no subsidies are available for power taken before the meter. A LCOE estimation of 80 € per MWh was assumed for these calculations, based on predictions made by the U.S. Department of Energy (2021) for floating wind. This number was also considered a reasonable estimation by representatives within RWE.

5.4 Case-Specific Quantitative Results

In this segment the case specific results regarding dimensions, costs, and emissions for each case modeled in MS Excel is presented.

5.4.1 Dimensions

Component dimensions and energy use
Table 3 shows key component dimensions and energy use of electricity and hydrogen, for the cases included in the analysis.

Table 3: Table of key technical dimensions for all cases.

Case	Vessel Type	Total Electricity Use [MWh/yr]	Electrolyser Power [kW]	Compressor Power [kW]	H2 Use [MWh/yr]	H2 Storage Capacity on Land [MWh]	H2 Storage Capacity on Ship [MWh]	Battery Capacity [MWh]
A. Diesel ICE, Utsira	CTV	0	0	0	0	0	0	0
B. H2 PEMFC, Utsira	CTV	4031	775	45	2558	14	13	0.2
C. Diesel ICE, Haugesund	CTV	0	0	0	0	0	0	0
D. H2 PEMFC, Haugesund	CTV	4787	922	54	3043	17	15	0.2
E. Diesel ICE, Haugesund	SOV	9	0	0	0	0	0	0.5
F. Diesel ICE + E-Bouy, Haugesund	SOV	1849	0	0	0	0	0	0.5
G. H2 PEMFC, Haugesund	SOV	9286	1806	105	5961	457	425	0.5
H. H2 PEMFC + E-Bouy, Haugesund	SOV	6950	993	58	3278	251	233	0.5
I. H2 PEMFC + PEMEC + E-Bouy, Haugesund	SOV	7121	1628	91	3278	0	61	0.5
J. Battery + E-Bouy, Haugesund	SOV	4096	0	0	0	0	0	47.4

As seen from table 3, all energy use and component dimensions for the CTV cases increases with transit distance, with the exception for the small unvarying battery size. For the hydrogen SOV cases, less electricity is used when substituting hydrogen production for in-park direct power supply via a charging buoy. However, it increases somewhat from case H to I, as the hydrogen that still must be produced stems from a PEMEC with a slightly lower efficiency as compared to an AEC. Comparing the same cases, the increased electrolyser power results from a shorter production time of 12 hours per day as compared to 19 hours per day. Regarding yearly H2 use, the amount is approximately halved from case G to H and I when a charging buoy reduces loitering H2 energy demand by $\frac{1}{2}$.

Total required electric power supply
Electric power supply for cases B, D, G and H is simply the sum of electrolyser and compressor power, which is equal to 0.82, 0.98, 1.91 and 1.05 MW, respectively. For case H, base load power supply from the charging buoy is 0.48 MW. In case I, where the electrolyser is included on the ship, the maximum power supply from the charging buoy is 2.20 MW to supply the base load and produce H2 simultaneously. Maximum power supply from the park for case J is reached if the battery is fully recharged after the first day of the work cycle, covering the transiting to the park, the base load, and $\frac{1}{14}$:th of the loitering storage required, which equates to 1.2 MW. More power could possibly be needed if there were some malfunction which disabled the possibility for charging during standard charge times, which would need to be recovered at a later time.

Analysis of hydrogen production space requirements
An estimation of the space required for hydrogen production per case is presented in table 4 below. The estimations include electrolyser maintenance area. As the CTV cases utilize daily refueling, they require only a small area for land storage. The SOV cases however, require a larger area as all fuel for two weeks of operation time must be stored in the case of back to back excursions. When a charging buoy is included, the required area for land storage is reduced by 77 m^2.

Table 4: Approximate area requirements for hydrogen production and land storage

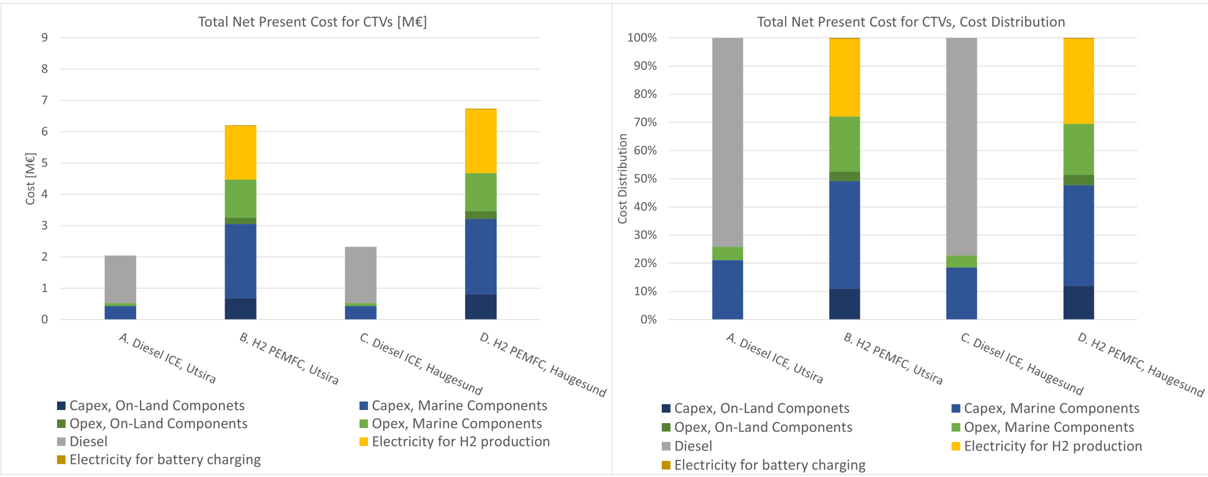
Includes maintenance area. Data sources for area requirements: AEC: Cummins (2021c), PEMEC: Cummins (2021b), Type I storage: Tenaris (2013)
*For case I, storage is only situated onboard the vessel, and a PEMEC is employed instead of an AEC.

Case	A	B	C	D	E	F	G	H	I*	J
Electrolysis $[m^2]$	-	89	-	89	-	-	89	89	198	-
Storage $[m^2]$	-	5	-	6	-	-	170	93	-	-
Total $[m^2]$	-	94	-	95	-	-	259	182	198	-

The area requirements for case I, where an electrolyser is installed on board the vessel, does raise questions regarding the feasibility of this system design. These results are further discussed in section 6.3. Note that on-ship storage is considered in figure 11b.

5.4.2 Costs

The total net present cost of each case was calculated in MS Excel. Figure 16 shows net present cost for the CTV cases as well as a percentage breakdown. The hydrogen solutions are 3.0 and 2.9 times more costly than the conventional diesel alternatives. When comparing the cases B and D, the increased transit distance drives up the yearly hydrogen consumption and the absolute disparity with the base case grows slighly wider. Furthermore, running costs, which includes opex and electricity costs, make up the majority of lifetime expenses at 50.8% and 52.3% for case B and D, respectively. The cost of fuel, which can be considered as the sum of costs for on-land components and electricity, makes up 42.2% in case B and 46.2% in case D.



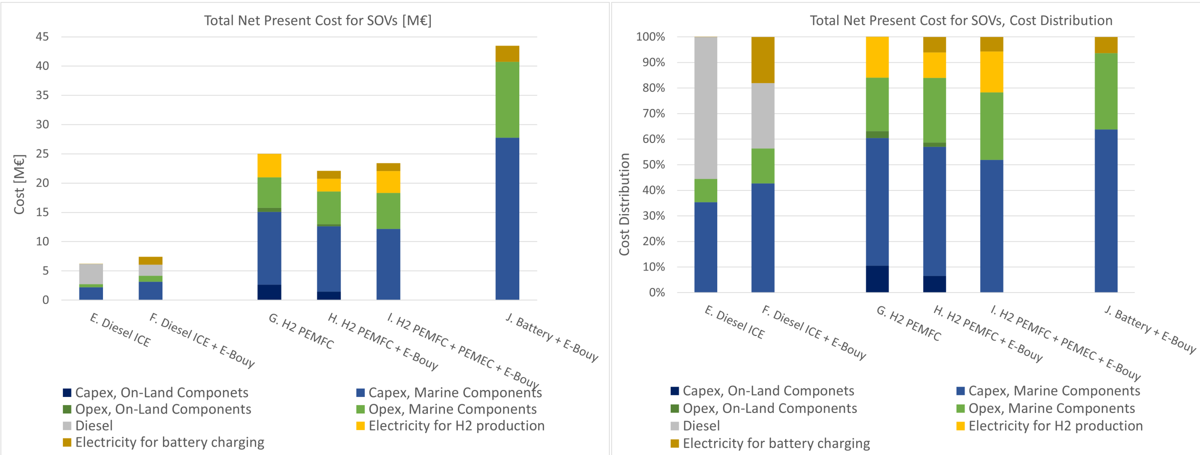
(a) (b)

Figure 16: NPV and cost breakdown for CTV cases.

Showing capex, opex, and fuel costs (a), as well as a percentual cost distribution thereof (b).

Figure 17 shows net present cost for SOV cases as well as a percentage breakdown. The alternative fuel and drive train solutions, i.e. cases G, H, I, and J, are 4.0, 3.6, 3.8, and 7.0 times more costly than the base case, respectively. The running costs make up a smaller part when compared to the CTV cases, landing on 42% ±6% of lifetime costs. The corresponding numbers for case F is a total cost increase of 1.2, and running costs make up 57%. Fuel costs for all these cases, which can also be said to include the charging buoy (thus not possibly discerned from figure 17b alone), make out 63.3, 29.2, 30.8, 36.7, and 9.7% for cases F, G, H, I, and J, respectively.

Of the alternative fuel and drive train solutions , case J has the largest, and H the smallest cost disparity compared to the base case. For the diesel cases, adding a charging buoy saves on the fuel costs, but the increased capital- and operation expenditure together with the high electricity price from the park exceeds these savings, resulting in a higher total cost. When comparing the H2 cases, G to I, it is seen that the inclusion of a charging buoy reduces the cost for on land components as the dimensions of these are lowered. The energy saving achieved through direct electrical transfer, partly subverting the need for hydrogen production, also lowers the total electricity cost, despite a higher price per kWh electricity taken from the park compared to the grid. These saving outweigh the increased expenses of the buoy itself. When hydrogen production is moved on-board the vessel, the higher electricity price for H2 production in the park, along with the larger dimension of the electrolyser needed due to shorter working intervals, exceeds the savings on removing H2 land storage.



(a) (b)

Figure 17: NPV and cost breakdown for SOV cases.

Showing capex, opex, and fuel costs (a), as well as a percentual cost distribution thereof (b).

When comparing all alternatives, both CTV and SOV, the smallest absolute cost disparity when compared against the base case, is found for case B, and the smallest relative increase is found for case D.

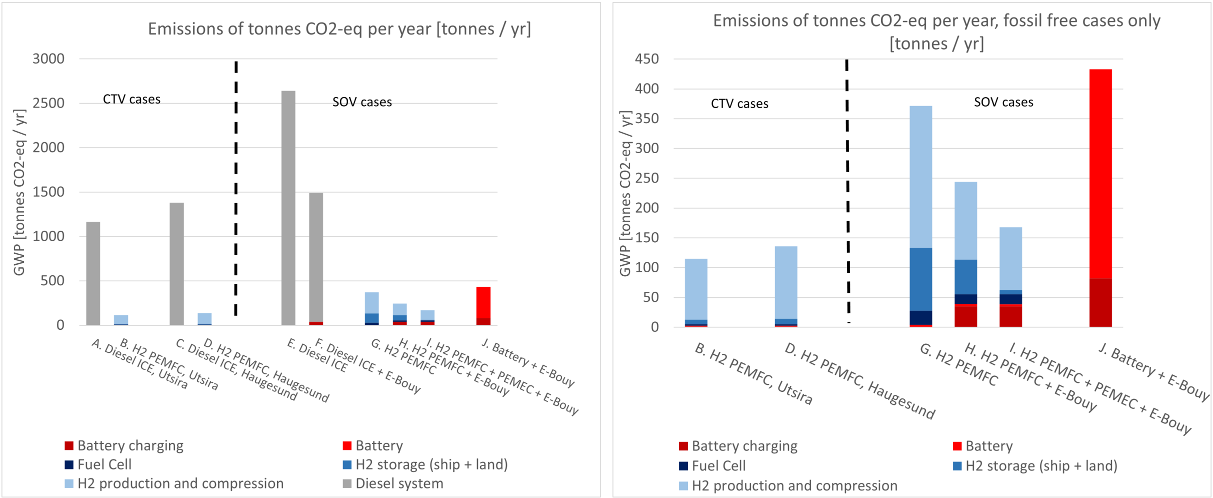
The fuel cost per MWh output for each case, and the LCOE of H2 for the hydrogen cases are presented in table 5 below. No big cost disparity is seen for the alternative CTV cases. For the SOV hydrogen cases, the cost correlates with the fuel related cost results seen in figure 17a, i.e. absolute on-land capex and opex as well as electricity expenditure. The SOV battery case has a low cost per MWh output as only the charging of the battery is included in this metric, and not its capex nor opex. The increase in LCOE when moving from the CTV to the SOV cases stems from the increased storage capacity necessary for the SOVs due to the 14 day work cycle. Each molecule of H2 produced needs a 14 times longer storage period, with the result that the storage cost per molecule and per kWh H2 is 14 times higher for the SOV cases. For case I, the on-land H2 storage cost is removed, but the electrolyser size and capex is increased by a factor of 1.86 due to the shorter time available for production. Since the cost contribution of the electrolyser is higher, it has a greater impact on the LCOE.

Table 5: Fuel cost per MWh output and LCOE of H2

Case	A	B	C	D	E	F	G	H	I	J
Cost per MWh output [€/MWh]	115	199	115	200	115	108	245	180	240	92
LCOE [€/MWh]	-	112	-	112	-	-	135	135	195	-

5.4.3 Emissions

The life cycle GWP of all alternative fuel and drive train cases are lower than their respective base case by a factor ranging from $\frac{1}{6}$ to $\frac{1}{15}$, and the inclusion of a charging buoy while still running conventional fuel achieves a reduction factor of about $\frac{1}{1.8}$. Figure 18a below shows the yearly emissions associated with each case.



(a) (b)

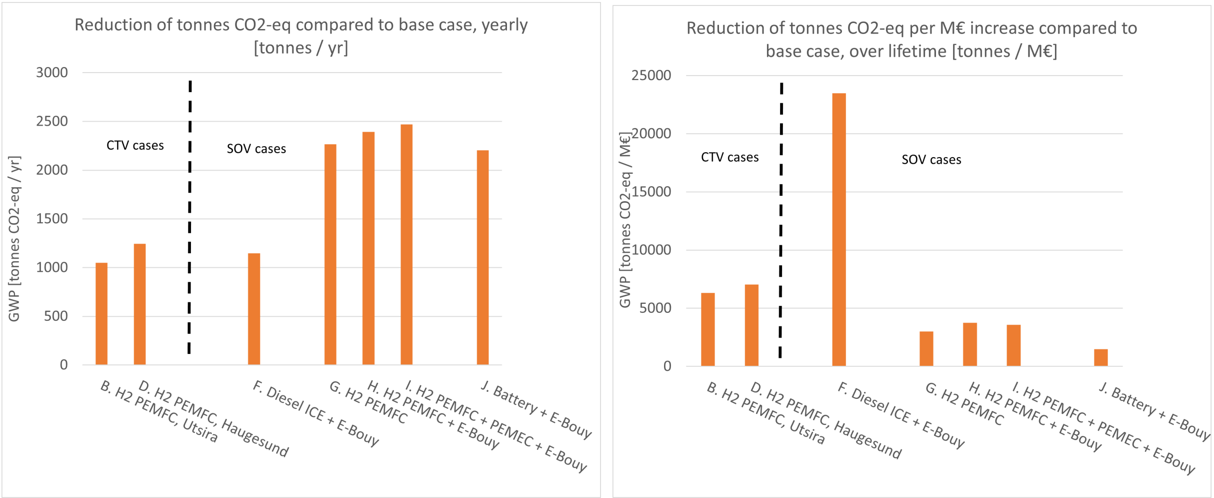
Figure 18: Yearly life cycle emissions for all cases.

Shown in tonnes $CO_2 - eq$ of all studied cases (a) and for all alternative cases (b).

For the CTV cases, it is seen from figure 18b that case D has a higher GWP than case B, resulting from a higher use of hydrogen due to the longer transit time and energy intensity thereof. Furthermore, the storage of hydrogen and utilization of the fuel cell, together with battery and charging thereof has only a minor contribution to the overall yearly GWP. Making a comparison between CTV and SOV cases. the emissions from H2 production in cases B and D are higher than for cases H and I, not because of a higher total use, but because all electricity is taken from the grid for the two former. In case H, some of this grid electricity for H2 production is substituted for park battery charging. In case I, 6% of electricity is taken from the grid and the rest is taken from the park.

Regarding the SOV cases, case J yields the highest emissions out of the alternative cases, with the majority stemming from the battery itself and a lesser part from charging. Charging emissions are kept low due to 81% of all electricity being taken from the park in this case. For the hydrogen SOV cases, emissions are cut by around 34% when a charging buoy is included, and cut again by around 31% if hydrogen production components are situated onboard the vessel. The initial cut is due to a decrease in loitering H2 energy and storage capacity, and the second cut is due to a complete lack of land storage and a further reduction of ship storage, together with an almost complete shift to electricity from the park as opposed to the grid, as described in the paragraph above.

The reduction in GWP by case, as compared to each respective base case (see tree of cases in figure 12), can be seen in figure 19a below. The reduction relative to the cost increase per case can be seen in figure 19b, which is calculated as the difference in emissions (same as figure 19a) divided by the difference in cost.



(a) (b)

Figure 19: Yearly life cycle emissions reduction and lifetime reduction per cost increase for alternative cases.

Showing the yearly reduction in tonnes $CO_2 - eq$ (a) and the lifetime reduction per M€ cost increase (b).

Out of the CTV cases, case D has a higher reduction, again due to the total fuel consumption being higher than case B. For the SOV cases, all alternative fuel and drive train cases, G to J, has a similar reduction compared against the base case, whereas case F has a reduction about $\frac{1}{2}$ of the others. However, due to the low added cost of only a charging buoy, the reduction per increase in cost is the highest for this case, being 6 times better than the next best SOV case (H) in that regard. Per increase in cost, case J is the worst of the SOV cases. The CTV cases are slightly less than twice as good as the SOV cases.

The inverse of the results in figure 19b yield the marginal abatement costs per GWP, which is simply the NPC over the reduction of emissions over the lifetime. These can be seen in table 6 below, which explicitly shows the cost associated with reducing the emissions per case. Again, case F performs the best, and case J the worst. Table 6 also shows the cost of CO_2 which would be needed for each case to break even with their respective base case. The difference between these two metrics is that the former allocates the discounted costs, i.e. the NPC, over lifetime reductions, whereas the latter allocates a yearly annuity over yearly reductions. The latter thus represents the price of CO_2 emission rights which would be needed in order to earn back the added costs associated with alternative solutions, assuming that emission rights are traded on a year by year basis.

Table 6: GWP marginal abatement cost and break even cost per case.

Case	**A**	**B**	**C**	**D**	**E**	**F**	**G**	**H**	**I**	**J**
Marginal abatement cost [€/tonne CO_2]	-	158	-	142	-	43	332	266	279	677
Break even CO_2 cost [€/tonne CO_2]	-	436	-	391	-	117	914	732	768	1863

5.5 Sensitivity Analysis

5.5.1 Cost Sensitivity Analysis

The results of the comparative sensitivity analysis can be seen in figures 20 and 21, for the CTV and SOV cases, respectively. Firstly, results of changes on single parameter or single components are shown, followed by an optimistic- and a pessimistic capex scenario. In table 7 below, the percentual capex differencees per component, which are used for the optimistic and pessimistic scenarios, are shown. The values behind these percentages correspond to the maximum and minimum of the values included in the literature study (see figure 9 in section 5.1).

Table 7: Table of percentual component capex difference for optimistic and pessimistic sensitivity analysis scenarios.

Scenario \ Component	PEMEC	AEC	Compressor	Storage type I	Storage type IV	PEMFC System	Battery System
Optimistic	-38%	-58%	-0%	-0%	-3%	-45%	-47%
Pessimistic	+60%	+49%	+0%	+0%	+0%	+4%	+26%

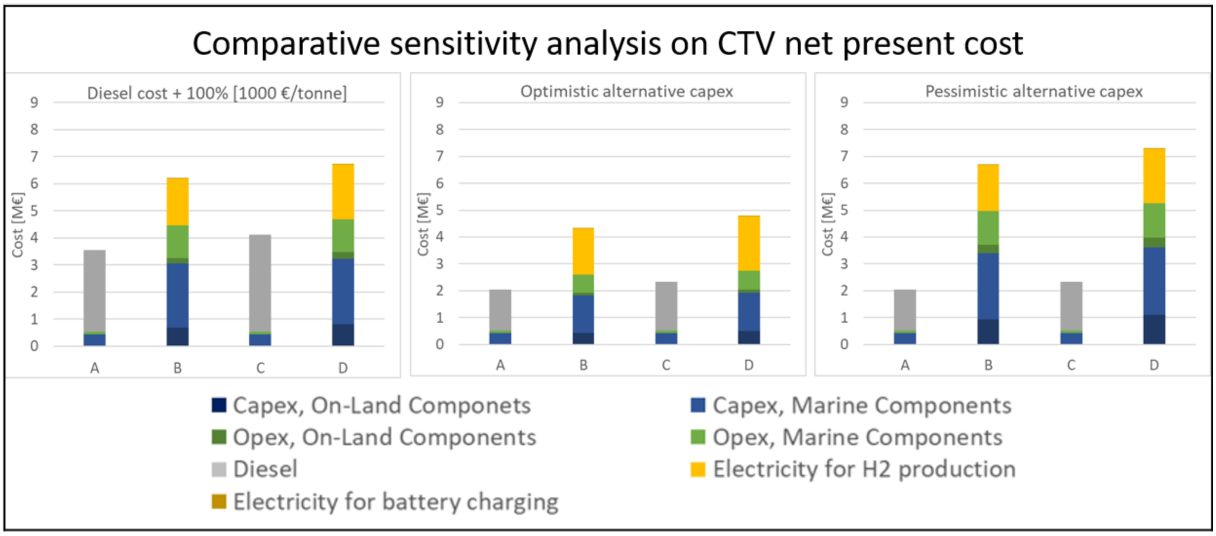


Figure 20: Comparative sensitivity analysis on NPC of CTV cases.

From left to right, figures portray a diesel cost increase, optimistic- and pessimistic capex scenarios.

It is seen that if MGO prices were to remain at the historically high current Norwegian prices, the cost of the hydrogen cases, B and D, would be only 1.7 and 1.6 times that of the base cases, as compared to 3.0 and 2.9 under standard conditions. For the hydrogen cases to reach cost parity with conventional drive trains, the diesel price would need to increase by 285%. From figure 20 it is seen that at the standard diesel price, no feasible component cost reduction for the hydrogen cases is enough to reach parity. Component cost increases are unlikely to affect the NPC more than around +1M€.

Looking at the SOV cases in figure 21, we see that if MGO prices were to remain at the high Norwegian price, the cost of the alternative cases would be only 0.9, 2.6, 2.3, 2.4, and 4.3 times that of the base case, as compared to 1.2, 4.0, 3.6, 3.8, and 7.0 under standard conditions. The diesel cost would need to increase around 500% for the base case to reach parity with the hydrogen cases. Examining cases G and H, it is seen in figure 21 that the cost of the charging buoy would need to increase 200% from the assumed cost before the investment becomes unprofitable. Furthermore, at the standard diesel price, no feasible component cost reduction for the alternative cases is enough to reach parity. Component cost increases are unlikely to affect the NPC more than +1-2 M€ for the hydrogen cases and +6M€ for the battery case.

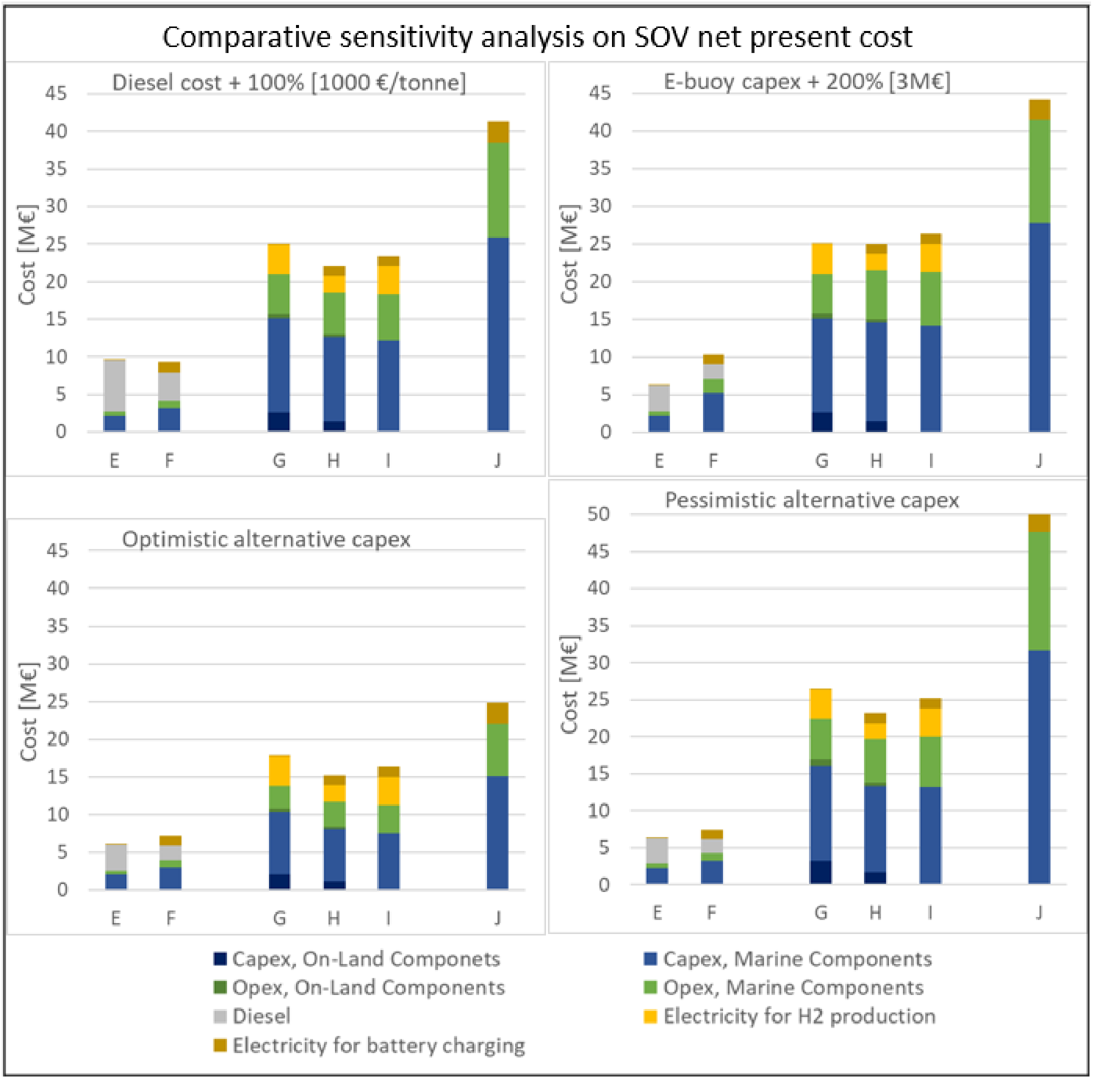


Figure 21: Comparative sensitivity analysis on NPC of SOV cases.

Top left and right figures portray a diesel cost increase and a charging buoy cost increase, respectively. Bottom left and right figures show optimistic- and pessimistic capex scenarios.

Table 8 below shows a global parameter sensitivity analysis of how electricity price and vessel fuel consumption affect the net present cost. The results in this table are presented as percentual change of the NPC compared to standard conditions. For electricity price, two price levels were examined: 217 €/MWh and 24 €/MWh. The high price was chosen based on the analysis of average yearly spot prices (see figure 14), where the highest average price in a year amounts approximately to 217 €/MWh (note - the year in question is 2022, where data is only included from January to October). The lower e-price (50% of the standard price) was chosen in order to see how a very low e-price would affect the NPC. It can be seen that changes in grid price particularly affects cases where large amounts of electricity is used in the harbour, i.e. cases with an electrolyser in port. Cases where a larger portion of electricity is supplied from a charging buoy are not as heavily affected by changes in e-price.

Vessel fuel consumption effect on NPC was examined in a span of ±50%. This particular parameter was analysed as it affects essentially all other calculations in the model, and the true fuel consumption could have considerable variations in a real world scenario. The effects of altering this parameter has varying, but generally considerable, effects on the NPC for the cases.

Table 8: Sensitivity analysis of how electricity price and vessel fuel consumption affect the net present cost.

Case	**Vessel Type**	**Relative NPC, NO2 E-Price + 350% [217 €/MWh]**	**Relative NPC, NO2 E-Price - 50% [24 €/MWh]**	**Relative NPC, Vessel Fuel Consumption -50%**	**Relative NPC, Vessel Fuel Consumption +50%**
A. Diesel ICE, Utsira	CTV	0%	0%	-37%	+37%
B. H2 PEMFC, Utsira	CTV	+97%	-14%	-24%	+24%
C. Diesel ICE, Haugesund	CTV	0%	0%	-39%	+39%
D. H2 PEMFC, Haugesund	CTV	+106%	-15%	-26%	+26%
E. Diesel ICE	SOV	0%	0%	-28%	+28%
F. Diesel ICE + E-Bouy	SOV	0%	0%	-22%	+22%
G. H2 PEMFC	SOV	+55%	-8%	-17%	+17%
H. H2 PEMFC + E-Bouy	SOV	+34%	-5%	-14%	+14%
I. H2 PEMFC + PEMEC + E-Bouy	SOV	+2%	0%	-16%	+16%
J. Battery + E-Bouy	SOV	+3%	0%	-49%	+49%

5.5.2 Emissions Sensitivity Analysis

Regarding the impacts on economical efficiency of emissions reduction in the comparative sensitivity analysis, the capex of the charging buoy must increases more than 575%, to 6.75 M€, for it to reach parity with hydrogen cases (H) on reduced tonnes CO_2-eq/ M€.

The sensitivity analysis on the choice of calculation method for determining the GWP and the following reduction compared to the base case is shown in table 9 below. Method one takes the life cycle emissions of fuels and of almost all components into consideration, whereas method two disregards life cycle emissions entirely and only accounts for the combustion of MGO or lack thereof, i.e. the end-of-pipe emissions.

Table 9: Emissions of each case for different calculation methods and the percentual difference thereof

Case	**A**	**B**	**C**	**D**	**E**	**F**	**G**	**H**	**I**	**J**
Life cycle reduction [tonnes CO_2-eq/year]	-	1050	-	1244	-	1146	2267	2394	2470	2205
End-of-pipe reduction [tonnes CO_2-eq/year]	-	970	-	1149	-	986	2196	2196	2196	2196
Percentual difference	-	-7,7%	-	-7,7%	-	-14,0%	-3,1%	-8,3%	-11,1%	-0,4%

The difference between the two calculation methods varies between -0.4 and -14 % depending on the case. The highest relative difference, as seen for case F (-14%), is almost equal to the relative difference between the combustion of MGO and life cycle emissions of MGO, which lies at -16.8%. The offset is due to the fact that some life cycle emissions in the standard cases E and F stem from the small battery installation and charging.

6 Discussion

In this section the various aspects of this work will be discussed, following the general structure of the report as previously laid out.

6.1 Delimitations

The main delimitation of the analysis was the selection of which renewable energy carrier systems to examine. As mentioned, the main reason to focus on hydrogen and battery systems was to adapt the project to fit the particular conditions of the prospective wind farm Utsira Nord. The qualitative auction process proposed by the Norwegian government provides incentives to investigate solutions which utilize innovative technology and reduce emissions from the wind farm. These aspects were central for the choice of energy carrier systems to investigate. Both energy carrier types examined, compressed hydrogen and batteries, as well as the emerging technology of charging buoys, could contribute to both technological advancement and reduced emissions.

Other renewable energy carriers could however have filled these purposes as well. Some renewable energy carriers with potential for the marine industry are accounted for in section 3.6. It is possible that ammonia, e-methanol, biofuels or other syn-fuels could have been good fuel candidates for the vessel types examined in this report. As seen in figures 7 and 8, some of these fuels may have both economic advantages as well as higher energy density when compared to H_2 and batteries. However, due to the ambition of RWE Renewables that the energy carriers for this project should be produced (or charged, in the case of batteries) self sufficiently at small scale on-site, the two energy carrier types examined are the most viable options due to the few steps required to produce hydrogen and the simplicity of charging a battery. Furthermore, competence and experience for hydrogen and battery solutions already exist within RWE. Should other fuels be chosen for the vessels at Utsira Nord, the fuel would likely need to be supplied by external parties.

6.2 Literature Study

Large variations and non-clear system definition in input data
As the results from the literature study regarding costs varied around the median values by as much as $\pm 60\%$ for some components as seen in figure 9 and table 7, the resulting cost of each case could be highly affected by a difference in input cost. Not all sources stated the exact system borders of their cost approximations, and for this reason there were difficulties when making comparisons. As seen from the sensitivity analysis in figures 20 and 21, the NPCs vary considerably, especially in the optimistic scenarios but less so in the pessimistic. This indicates that conservative values were chosen as the standard input costs. At scale, certain components may well fall below the chosen input values, which is discussed further in section 6.5.2.

High deviations were also noted in LCA studies on GWP, most significantly for floating wind power ranging from about 10 to 40 CO_2-eq/kWh. Although the input value would impact the results, the relative difference compared to the fossil drive train cases would still remain high.

Limited data on fuel consumption and operating pattern of service vessels
Two main input parameters to the dimensions and cost model are the fuel consumption and the operating pattern of service vessels. The former of these has been only partly verified between several sources, as data on CTV fuel consumption could be compared between vessel data-sheets but SOV transit fuel consumption stems from one paper only (due to not being disclosed in data-sheets). The operating pattern is subject to variations on both hourly and yearly timescales, and the examination of these are not within the scope of this report, and only a yearly assumed capacity factor is used. However, differences in operational routine on smaller timescales could influence the average loitering energy requirements. Vessel operating pattern is also dependent on park layout, e.g. how much time is spent traveling between turbines and how much is spent idling. All these uncertainties could accumulate and affect the results, yielding either lower or higher total net present costs.

Validation of input parameters
Most input parameters have been cross-examined over several sources to verify their validity and to enable the selection the most representative data. However, not all data, such as that discussed in the paragraph above, has been subject to such stringent examination due to lack of source material. The amount of source material and cross-validation on any specific topic covered in the report is partly reflected by figure 9. Aspects regarding conventional technologies were deemed less speculative, and as such fewer data points regarding their characteristics were gathered.

6.3 Determination of Cases

The determination of cases was a challenging but key part of the process. As there were very many parameters that could be altered in the design of each case, many scenarios had to be excluded from the analysis in order to keep the number of cases within reasonable bounds. The total number of cases could have been greater than 100 if all feasible parameters had been investigated for each case.

Hydrogen-diesel hybrid drive trains
It would have been interesting to examine cases where both conventional diesel engines and H_2 fuel cells are implemented on the same ship - a solution explored by the Norwegian ship manufacturer Ulstein for their under-development offshore support vessel, where 2 MW of the total 7.5 MW installed power on the vessel is supplied by PEMFC. With such designs, it could be possible to utilize hydrogen energy to the greatest practical extent, while still having the option to fall back on diesel power when the hydrogen system is insufficient. This approach could be a good way to reduce emissions in a cost effective way, as the hydrogen system could be used to reduce emissions in the "easy to abate" part of operations, while the diesel system remains the key player in more demanding situations. To dimension such a system and calculate costs and emissions of fuels, one would need data on the vessel propulsion load over the lifetime, or apply some approximation thereof. As such load data and vessel modeling lay outside the scope of this report, and its approximation would be highly speculative, only the fully alternative technology cases were examined. As discussed in sections 6.5.2 and 6.5.3 however, strong benefits of a hybridised system are probable. Furthermore, it would also have been interesting to further examine ICEs capable of operating with dual fuel or pure H_2 capabilities. Due to the higher efficiency of PEMFC propulsion systems however (shown in figure 8), and the higher degree of novelty of this technology, fuel cells were chosen for the on board drive train.

Choice of harbour
The decision to only examine two harbours was made in contrast to the fact that other harbours in the region could be chosen for the O&M service base. As Utsira Island provides a unique opportunity to have the service base in close proximity to the wind farm (< 10 km), which would minimize time in transit and fuel consumption from park to service base, this alternative seemed particularly suitable for scenarios with CTVs. One could however speculate that having a service base on an island could be impractical in terms of logistics, for example when ordering spare components or other required materials. Haugesund was chosen as it is the nearest large harbour. There are other large harbours within feasible ranges from the wind farm as well, but as these seemingly had no advantages compared to the nearer Haugesund, this harbor was selected.

Vessel type
During early stages of the project, it was hypothesised that CTVs with harbour at Utsira Island would likely be the best alternative for the purpose at hand. However, due to the floating foundations and depending on the local ocean conditions, it is possible that SOVs could be more suitable for Utsira Nord. The uncertainty regarding which vessel type is most suitable led to both vessel types being included in the analysis. Even if one vessel type would be deemed unsuitable for the offshore wind farm in question, the results from this report could be applicable for other wind farms where these vessel types are suitable.

Standards and regulations
One aspect that is not examined in this report is the legislative maturity of the energy carrier systems included. There could be problems related to lack of standards and regulations for these propulsion systems. This is something that could have considerable effect on the actual viability of the projects, and must be examined further before any project could be realised. This could particularly be a problem for the case where an electrolyser is installed on board the vessel, as this would likely be an uncommon design.

Vessel with PEM electrolyser on-board
During the writing process, an idea was conceived that if a vessel would be able to produce hydrogen on board the ship itself, whenever sufficient power is provided, it would eliminate the need to have expensive bunkering infrastructure in harbour. As a PEM electrolyser is essentially the same kind of electrochemical machine as a PEM fuel cell, but operating in reverse, it could be a feasible idea to install a PEM electrolyser on board a vessel. The main benefits of this system design is that no hydrogen facility will be required in the harbor, reducing costs for hydrogen storage and costs related to lease or purchase of land in the harbour. What would be required in the harbour is access to sufficient electric

power at the mooring point. The concept would consume some of the vessels storage volume and mass carrying capacity. The analysis in section 5.2.2 indicates that the vessels could handle greater loads in these categories. The analysis of area requirements however, indicate that a PEM electrolyser could require an area of 198 m^2. This number includes balance of plant components and maintenance area. There is some uncertainty regarding how this area is utilized. The actual PEMEC stack likely requires much less space (< 20 m^2), according to data sources from the same manufacturer (Cummins 2021a). Further, the required power for the PEM electrolyser (≈ 1600 kW) would be significantly lower than the required power for the PEM fuel cell (≈ 7800 kW), which could mean that the PEMEC would require less space compared to the PEMFC on board. The actual area, volume and weight requirements of this system approach would need to be examined in depth in order to determine if it is possible. Conclusions regarding the feasibility of this concept will be left to be drawn by vessel manufacturers. This case is mainly included in the analysis as an interesting avant garde idea for possible future innovation in the offshore sector.

6.4 Electricity Price

Predicting future prices
The results from the historical spot price analysis showed that the prices in Norway have been relatively stable from 2002-2019, but that the last three years have seen greater fluctuations. There could be many reasons for this, as electricity pricing is a complex matter that depends on physical and political circumstances. The fluctuations in recent years give reason to question the accuracy of price predictions for 2030 and after. However, as the future is difficult to predict with accuracy and the simulation performed by Statnett was deemed as the most credible source available, the proposed electricity price of 48 € per MWh was adopted.

Utilization of low-price hours
The hourly price optimization is based on market data from the last 5 years. It is possible that patterns for electricity use could change in the future, as new technologies emerge and people adapt to a more dynamic electricity system. The increasing share of intermittent electricity in the energy system could also affect the trends in this market, as wind power generally produces more power at night and photovoltaics produce power when the sun is out. The basic daily routine pattern for most people (i.e. getting up in the morning around 7:00 and getting home from work around 18:00) would however seem as something which can remain quite unchanged in the future. As the spot market prices seems closely related to these daily patterns, it is feasible that similar price trends will exist in the future as well. Predicting the future is always difficult, which should be kept in mind when considering the results and economic consequences from the price variation analysis. One aspect which was not analysed in depth in this report is the trend of lower e-prices during weekends. This is something which could be investigated further in order to minimize the costs from electricity use.

Using self-produced electricity
It was unexpected to find that the cost for using electricity directly from the wind farm would be more expensive than purchasing power from the grid. Initially, it was believed that it could be cheaper to utilize the electricity produced by RWE, as taxes and other potential fees could be avoided. The consequences of this relationship is that it will not be economically beneficial to construct a charging/refuelling station with the intent of using self-produced electricity, rather than one where grid electricity is used. It is possible that subsidies could exist for use of electricity for production of renewable energy carrier applications, but for the scenario at hand it was considered speculative and therefore excluded from analysis.

It is possible that using self-produced electricity could have other values for RWE than the purely monetary. As the auction process for Utsira Nord is based on qualitative criteria, it is possible that a project proposal which includes a self-reliant green energy carrier system for O&M vessels could favor the bid from RWE.

6.5 Case-Specific Quantitative Results

6.5.1 Dimensions

Scale and capacity factor of H2 production and storage
The production and storage of H2 was modeled and dimensioned as to support continuous vessel operation, which is not the only viable solution. A solution which was not examined in this report is the

downscaling of H2 production with a subsequent higher electrolyser CF and larger storage capacity. This alternative could support back-to-back service operations by providing H2 from extra storage capacity when production does not manage to keep up, and storage would be restocked during vessel standby. Cost optimisations are possible, however preliminary testing on these parameters for case H showed only a possible LCOE decrease of 0.5%, which would probably be negated by the increased cost of storage footprint which is not included in the model.

Magnitude of power supply from the charging buoy
The power supply from the charging buoy supplied by the park has its highest value of 2.2MW (for case I). It is deemed probable that this amount of energy would usually be accessible as this amounts to only 0.4% of a possible 500MW park. At times when there is no wind, power could be supplied via the grid. To more exactly determine the proportion of time where grid supply would be necessary, a wind data analysis and a more detailed vessel operation model would be needed.

Hydrogen storage and vessel carrying capacity
The volume of compressed H2 storage partly exceeds the capcity of CTV vessels. This problem would possibly necessitate some extra consideration in vessel design, as to accommodate extra storage volume either on-deck or in other spaces. For the SOV cases, this issue is entirely negated when a charging buoy is included, as the volume necessary for storage then drops by 50%.

6.5.2 Costs

Cost comparisons with other studies
It is interesting to comparing the findings of DNV GL (2019b) which are presented in figure 8, with the results in table 5. In figure 8, the cost per MWh propulsion of different fuels is presented. No base case scenario is given, but fossil alternatives present median costs of around 40 to 90 €/MWh, depending on fuel choice of LNG or LPG. Propulsion via renewable H2 and fuel cell drive train of around 260 €/MWh is presented, with a span ranging from 120 to 500 €/MWh. The battery alternative has a median of 200€/MWH and ranges from 30 to 380 €/MWh.

Examining the results of this report in table 5, the base cases fall just outside the higher end of the fossil alternatives presented in other findings, at 115€/MWh. Conservative numbers on drive train efficiencies have been employed throughout this report (for all drive trains), which could be an explanation for this. The alternative solutions give a fuel cost for the hydrogen cases ranging from 199 to 245 €/MWh, which is within the lower span of other sources. This is reasonable as future price reductions on electrolysis would bring down the cost of fuel. The battery alternative lies in the lower span of other sources at 92€/MWh, which is reasonable as this correlates well with the price of power from the park at 80€/MWh. In comparison the proposed cost from other sources seems high, as the conversion from electricity to propulsion has a high efficiency at around 0.8.

When comparing fuel production costs, findings by DNV GL (2019a) on future H2 prices based on Norwegian production at between 105 and 123€/MWh lie close to our findings at 112 and 135 €/MWh for cases B, D, and cases G, H, respectively. Case I presents an outlier in that regard, with an LCOE at 195 €/MWh, which stems from the larger dimension electrolyser with lower capacity factor.

When examining the total cost disparities, the study by Grzegorz Pawelec (2020) presents comparable numbers for the SOV hydrogen cases. In this study, costs for a platform supply vessel which is similar in size and operations to an SOV, are examined. The theoretical vessel in questions employs a PEMFC together with compressed hydrogen for its power supply, and a total cost of ownership per year for fuel, storage, and power converter is calculated and compared to an MGO ICE base case. Although the metric used is not the same as in this report, the relative cost compared to the base case is of interest. In their findings, Grzegorz Pawelec (ibid.) report a cost for the CGH2-PEMFC case about 2.1 times that of the base case. The corresponding number in this report is 4.0. However, in their report, the cost of the PEMFC is about equal to that of the ICE, which also corresponds to the cost per fuel cell stack, and not the system. This cost is about $\frac{1}{4}$ that of the system cost used in this report, as as the PEMFC is the largest single cost driver, the impact of this input parameter is significant. When correcting for the differences in this term by setting the PEMFC system cost equal to that of the ICE system, the number for this report is instead 2.3, resulting in only a 5% difference between the reports when numbers are not rounded. As such, all other things considered, the results support each other.

Costs in relation to total park cost and park operational expenditure
To put the additional costs of alternative cases into perspective, it is interesting to compare these in

relation to the total cost of a floating wind power project, and the operational expenditure thereof. As costs for different projects are dependent on many parameters, any generalised number must be considered as highly approximative. However, in a study by Martinez and Iglesias (2022), such a number is provided. Based on a 1000 MW floating park, at a distance from shore of 100 km, the total cost is estimated at 4500 M€, of which about 1000 M€ from operational expenditures. With a very rough assumption that a 500 MW park, as considered in this report, yields half the above reported costs, the cost increase from implementing alternative solutions lands at around 0.05 to 1.7% of the total and 0.12 to 3.7% of operational expenses. The lower values correspond to the charging buoy case (F), and the higher to the battery case (J), whereas hydrogen cases (B, D, and G-I) land in the middle between these.

Cost of CO_2 emissions
The cost of CO_2 emissions under the EU ETS scheme is not incorporated into the model, but this would decrease the cost disparity between alternative fuel and drive train solutions compared with the base cases. The cost development per unit CO_2 during the lifetime of the studied systems is unclear however, and as such this impact would be difficult to accurately quantify. Estimation based on current ETS prices of 90€/tonne CO_2 results in additional NPCs between 0.8 and 1.8 M€ for fossil fuel cases based on end-of-pipe emissions calculations. Based on the break even CO_2 costs presented in table 6, the above price on CO_2-emissions is not enough to reach cost parity with any base case. However, an increase in EU ETS prices over the lifetime, could possibly result in cost parity for case F, but this would still require a CO_2 price increase of over 30%. For all other cases, this is unlikely.

Reducing costs for high powered vessels
As seen examining figures 16 and 17, the share of on-ship capital expenses is about 50%, and the absolute cost becomes quickly increases for the larger vessels. The main cost driver is the PEMFC system due the high capex and opex thereof. As such, the larger the required maximum shaft output, the less appealing the case for 100% PEMFC solutions. In these cases, another energy conversion method could be desirable, such as hybrid solutions discussed in section 6.3. Depending on the load profile, it could be possible to achieve a high degree of decarbonisation at a lower capital cost, if a smaller PEMFC could cover the majority of the base load.

Linearity of cost scaling
The cost model in this report does not take into consideration the effect of price reductions when components or products are ordered and installed at scale, but instead follows a linear scaling. Especially the cost of power conversion components, i.e. PEMFC and battery systems, might err on the side of overestimation in that regard.

Up-scaling of hydrogen production
Up-scaling of hydrogen production in order to e.g. supply O&M vessels for neighboring wind power sites could be possible at price ranges indicated by the LCOE found in this report. If scaling would be carried out in a similar fashion as modeled, retaining the same capacity factors on electrolysis components and compressors, the LCOE would not increase. An increase in LCOE could stem from changes in storage logistics, as noticed when storage volume increased from 1 to 14 days capacity (see table 5). Aspects not considered are the costs of altered footprint and fueling equipment. However, a decrease in LCOE could also be achieved if component capacity factors were increased. This is possible, as the current systems are dimensioned to support back-to-back vessel operation cycles, and to operate only when vessels are also operating, at a CF of 0.7. The same system could thus be brought to operate at a higher CF, generating more H2 and lowering the LCOE. Increasing the CF to 1 (this does not mean that electrolysers are working 100% of the time, as the daily price optimisation is still limiting operation to 19 hours per day) yields an LCOE of 103 and 119€/MWh at 1 and 14 days of storage, respectively.

6.5.3 Emissions

Total life cycle decarbonization is impossible under the current structures of society where fossil resources are the backbone. However, if aiming to reach the highest degree of emissions reductions over the life cycle, all hydrogen cases represent good alternatives. However, when comparing the emissions reduction per investment increase, it becomes evident that the fully decarbonised SOV cases are not economically efficient, since a conventional drive train with the simple addition of a charging buoy performs six times better in this regard. This potential cost saved could be used for other efficient mitigation measures. Still, there are other perspectives than the economical, and this case (F) will result in emissions four times larger than when fully decarbonising, and will yield only marginal technological innovation when compared to other alternative cases. As discussed in section 6.5.2, a middle ground may again be preferable, choosing a hybrid system with both PEMFC and conventional ICE. In cases where CTV solutions are possible, these are more economically reasonable, both in absolute terms and in emissions reduction per investment increase.

As discussed in section 6.2, high variations on values of GWP over the life cycle of components were observed, leading to uncertainty in the results. A metric which is less uncertain, but not as representative of the actual associated emissions per case, is the end of pipe emissions. These could be regarded as the direct emissions caused by the combustion of fossil fuels, in which case GWP would only be ascribed to the fossil drive train cases whereas the alternative cases would be considered as contributing zero GWP. When applying this metric, the emissions reduction per case is altered by -0.4 to -14.0%. Which of these two metrics one would wish to present depends on the application thereof by the recipient, and on the level of certainty desired.

6.6 Sensitivity Analysis

As seen from the comparative sensitivity analysis, it is unreasonable to expect that alternative systems will be economically competitive with the conventional fossil driven systems, as no realistic increase in fossil fuel price nor component cost decreases closes the cost disparity, except for in case F, where a charging buoy could be economically viable at very high MGO prices. Furthermore, it is seen that the report standard for cost predictions are quite conservative, as the effects on NPC in the pessimistic scenario are not as great as those in the optimistic scenario.

As the cost of the charging buoy is based on assumption, the performance of its implementation regarding emissions reduction per cost increase is uncertain. However, it is likely to be cost efficient in this regard as it retains the best position of all SOV cases even if the assumed price were to increase by 575%.

When examining the global parameters, it is seen that the alternative drive trains are not as sensitive to changes in e-price as one would expect. Especially when the price is halved, only a 5 to 15% decrease in NPC is noticed. For extreme and prolonged price increases, as those occurring in 2022 but extended over the entire lifetime, costs only double in the most affected scenario, which points towards surprisingly resistant systems. For fluctuating vessel energy consumption, the CTV cases are more sensitive, as the share of fuel costs is higher for these cases, with the exception of case J, where the energy converter and energy storage is encompassed in the same component. For the other SOV cases, only small savings could be expected from fuel efficiency measures.

6.7 Project Circumstances in Norway

Auction process and governmental ambitions for the industry

The current government in Norway has stated that the value chains for offshore wind, batteries, hydrogen, and the maritime industry are among the priority areas in their "Green Industrial Initiative" (Ministry of Trade, Industry and Fisheries 2022). The suggested qualitative auction terms for Utsira Nord indicate that they are taking action in the development of these areas (with particular respect to the value chains for offshore wind, in the case of Utsira Nord). As the suggested criteria indicate that lower CO_2 emissions per MW can be weighted positively for the wind farm proposals, reducing emissions in the O&M phase could improve the chances of winning the bid process. The share of emissions from the O&M phase in floating wind power has been estimated to 30% of GWP/kWh (Garcia-Teruel et al. 2022), reducing emissions in this category could therefore have considerable effects on the total GWP from a wind farm. On the other hand, the suggested criteria also state that low estimations of LCOE for the wind farm proposals will be beneficial. The fossil free solutions investigated in this report have considerably increased costs for the O&M vessels. If these costs increase the LCOE of the wind farm to a noteworthy extent, it can have negative consequences for the bid. As discussed in section 6.5.2, it appears that the costs for a project like this would increase the total costs of the wind farm project by less than 0.3% and the total O&M costs by less than 1%. As the suggested criteria indicate that both low LCOE and low GWP/MW can be sought after in the auction process, it would be essential to reduce emissions in a cost effective way. As the auction criteria are currently under evaluation and can be altered before the final publishing, no final conclusions can be drawn as of yet.

One aspect of the suggested criteria concerns local spillover effects, where contribution to increased industrial competence and development of the supply chain is valued positively. It is possible that a project which utilizes technology supplied by domestic developers could have advantages from a governmental perspective. As the O&M vessel solutions in this report are in line with the priorities of the Green Industrial Initiative, it could be beneficial to present which industries would benefit from an implementation of the service vessel solutions presented in this report. As accounted for in section 5.1.2, there are several companies in Norway that develop technology which would be relevant for low-emission service vessels. Cooperating with such companies would contribute to the development of Norwegian value chains for hydrogen, batteries and sustainable shipping.

Regional hydrogen supply & demand
It is possible that other businesses in the region near Utsira and Haugesund could have shared interests in access to renewable hydrogen. As Haugesund is a large port, it is feasible that in a future scenario there may be other companies and shipowners that would be interested in a reliable supply of hydrogen in the harbour. Either for use as a marine fuel, or possibly for use as a feedstock in local industry. In either case, a larger demand would require upscaling of the production capacities. It could however be questioned if this hydrogen production facility would be competitive in terms of cost with large-scale production facilities. Having the production facility in close proximity to the harbour would however minimize or eliminate transportation costs, potentially enabling a more competitive price. Furthermore, if the turnover of hydrogen could be kept high, as to reduce storage time and capacity, the LCOE of hydrogen produced on-site could also contribute to competitive prices, as discussed in section 6.5.2. The cost of land purchase or lease would also affect the hydrogen costs, these could potentially be higher in a harbour compared to inland areas.

7 Conclusions

Based on the findings from this report, the following can be concluded regarding the examined solutions.

- Decarbonisation of O&M vessels is possible but expensive (at the lowest 2.9 times more expensive)
- Hydrogen system pros include: lowest life cycle emissions, contribution to technological innovation, synergies with current developments in Norway.
- Hydrogen system cons include: high costs, high mass, large volume, large on-land area requirements.
- Battery system pros include: low life cycle emissions, small on-land area requirements, low complexity system, synergies with current developments in Norway.
- Battery system cons include: very high costs, very high mass and large volume. Not possible without offshore charging capabilities.
- Implementation of an offshore charging buoy has potential to reduce fuel consumption and emissions.
- Charging buoy pros include: reduced fuel consumption, contribution to technological innovation, exchange from chemical fuel to electric energy, reduced energy storage requirements, low complexity system.
- Charging buoy cons include: emissions remain high overall when applied as the sole reduction measure. No price estimations available.

Below, the research questions regarding decarbonisation of the O&M vessels for Utsira Nord are explicitly answered.

Which energy carrier systems would be most suitable as a replacement for fossil fuels in O&M vessels, in regards to production, storage and drive-train?
Of the thoroughly investigated solutions - compressed hydrogen and lithium-ion batteries - the former is the most suitable in terms of cost and emissions reduction, and the only possibility for smaller vessels with lower mass and volume carrying capacity. Further investigation on component costs and energy demands of other systems is necessary to draw a final conclusion based on a comparison of all feasible energy carriers.

Which technical components would be required for these systems and in what scale would they be needed?
Required components and scales thereof, excluding power conversion and actuator, are summarised in table 3. For hydrogen systems, alkaline electrolysers were determined as the most suitable option for

most cases. For land storage, type I tanks were chosen. For on board vessel storage, either type I or IV tanks were found to be suitable depending on the vessel type. PEM fuel cells were chosen for the on board energy conversion of hydrogen. Li-ion batteries were chosen for the full electric systems. The implementation of an offshore charging buoy has significant benefits in terms of reduced fuel requirements for SOVs. Both hydrogen and battery solutions would require fuel production/charging capacities in the range of 1-2.2 MW of power input. Hydrogen systems would require a land area of about 90 m^2 for production and approximately 5, or 90 to 170 m^2 for storage tanks depending on vessel type and in-park power availability.

What would be the predicted costs for each system?
The cost of CTV and SOV full hydrogen fuel cell solutions is found to be 2.9 and 3.6-4.0 times that of conventional systems, respectively. For the SOV battery solution that number increases to 7.0. The net present cost for CTV and SOV hydrogen solutions is around 6 M€ and 22-25 M€, respectively. The net present cost for the SOV battery solution is around 43 M€. The above results from a discount rate at 10% and a 25 year lifetime.

What would be the environmental impacts of each system?
From a GWP and life cycle perspective, the SOV conventional drive train with the addition of a charging buoy would emit 1500 tonnes CO_2-eq/year. The hydrogen CTV and SOV solutions would emit between 100 and 150-350 tonnes CO_2-eq/year, respectively. The SOV battery solution would emit around 400 tonnes CO_2-eq/year. Comparing against each respective base case, the addition of a charging buoy achieves a reduction of 1100 tonnes CO_2-eq/year, the hydrogen CTV and SOV solutions achieve a reduction of 1000-1200 and 2200-2500 tonnes CO_2-eq/year, respectively, and the SOV battery solution has a reduction of 2100 tonnes CO_2-eq/year. If life cycle emissions are disregarded, and only the end-of-pipe emissions from MGO combustion are considered, the resulting reduction achieved by each respective alternative case is around 10% lower than the above numbers.

How well does each system contribute to fulfilling the criteria of the Utsira Nord auction?
Hydrogen systems have the highest contribution in fulfilling auction criteria, due to lower emissions and lower costs than battery systems. All examined technologies have synergies with Norwegian industry and supply chains of green technology.

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Appendix

Below, tables with used parameters and assumptions are listed.

Service Vessel Data	CTV	SOV	Unit	Source
Fuel Type	MFO	MGO	-	(Anthony Gray 2021)
Fuel Consumption per hour, Transiting	320	1000	L/hr	(Anthony Gray 2021)
Fuel Consumption per hour, In-field	130	120	L/hr	(Anthony Gray 2021)
Transit speed, average	46.3	22.2	km/hr	(Windcat 2018), and assumption
ICE Power	1790	7800	kW	(SEAZIP 2015), (Wärtsilä 2014)
Battery storage	200	500	kWh	(HST 2022), and assumption
Cargo capacity	6	4500	metric tonnes	(Acta Marine 2022), and assumption
Fuel volume	15	700	m^3	Assumption
Work Cycle (time away from port)	9	336	h	Assumption
Capacity Factor	70	70	%	Assumption
Ship Fuel Storage Reduncancy Factor	1.3	1.3	kWh/kWh req.	On basis of (Anthony Gray 2021)

Marine Fuel Oil Properties	Value	Unit	Source
Energy content, Gravimetric	39	MJ/kg	(Engineering ToolBox 2003)
Density	980.0	kg/m3	(Engineering ToolBox 2003)

Marine Gas Oil Properties	Value	Unit	Source
Energy content, Gravimetric	42.8	MJ/kg	(Engineering ToolBox 2003)
Density	855	kg/m3	(Engineering ToolBox 2003)
Cost	500	$/metric tonne	(Grzegorz Pawelec 2020), (Scrap Monster 2022a)
CO2 emissions end of pipe	273	g CO2 / kWh	(Lindstad et al. 2020)
CO2 emissions lifecycle	322	g CO2 / kWh	(Lindstad et al. 2020)

Fossil fuel storage (MFO and MGO) Properties	Value	Unit	Source
Lifetime	30	yr	(Korberg et al. 2021)
Capex (storage)	0.09	€/kWh	(Korberg et al. 2021)
Opex (storage)	2	%	Assumption

Electricity Properties	Value	Unit	Source
Price from wind park	80	€/MWh	(U.S. Department of Energy 2021)
Spot market price	48	€/MWh	(Statnett 2021)
Norwegian tax rate	0.546	€/MWh	(The Norwegian Tax Administration 2022)
CO2-eq emissions from grid	25	g CO2 / kWh	(Our World in Data 2021)
CO2-eq emissions from park	18.9	g CO2 / kWh	(Garcia-Teruel et al. 2022)

Hydrogen Properties	Value	Unit	Source
Energy Content, Gravimetric	120	MJ/kg	(Engineering ToolBox 2003)
Energy Content, Volumetric (350 bar)	2820	MJ/m3	(CMB.TECH 2022b)

Hydrogen Storage Properties type I @ 350 bar	Value	Unit	Source
Gravimetric H2 density	1,7	wt% H2	(Rivard, Trudeau, and Zaghib 2019a)
Volumetric H2 density	13	kg H2 / m3	(Tenaris 2013)
Land storage redundancy factor	1.4	kg/kg req.	Assumption
Land storage area footprint	4.2	m3 / m2	(Tenaris 2013)
Lifetime	30	yr	(Grzegorz Pawelec 2020)
CO2-eq emission	3	kg CO2 / kWh H2	(Suer, Traverso, and Jäger 2022), (Tenaris 2013)
Capex	2.49	$/kWh	(Rivard, Trudeau, and Zaghib 2019a)
Opex	2	%	(Grzegorz Pawelec 2020)

Hydrogen Storage Properties type IV @ 350 bar	Value	Unit	Source
Gravimetric H2 density	5.5	wt% H2	(Durbin and Malardier-Jugroot 2013)
Volumetric H2 density	18	kg H2/m3	(Langmi et al. 2022)
Lifetime	30	yr	(Grzegorz Pawelec 2020)
CO2-eq emissions	12	kg CO2 / kWh H2	(Usai et al. 2021)
Capex	15.4	$/kWh	(Durbin and Malardier-Jugroot 2013)
Opex	2	%	(Grzegorz Pawelec 2020)

PEM Electrolyser Properties	Value	Unit	Source
Hydrogen production per MWh	19.7	kg H2/MWh	(Danish Energy Agency 2017)
Lifetime	66125	h	(Schmidt et al. 2017)
CO2-eq emissions	1	g CO2 / kWh H2	(Bhandari, Trudewind, and Zapp 2014), (Delpierre et al. 2021)
Capex	650	€/kW	(Danish Energy Agency 2017)
Replacement Capex	260	€/kW	Assumption
Opex	7	%	(Danish Energy Agency 2017)

Alkaline Electrolyser Properties	Value	Unit	Source
Hydrogen production per MWh	20.4	kg H2/MWh	(Danish Energy Agency 2017)
Lifetime	62250	h	(Schmidt et al. 2017)
CO2-eq emissions	1	g CO2 / kWh H2	(Bhandari, Trudewind, and Zapp 2014), (Delpierre et al. 2021)
Capex	570	€/kW	(Danish Energy Agency 2017)
Replacement Capex	228	€/kW	Assumption
Opex	5	%	(Danish Energy Agency 2017)

Compression Properties	Value	Unit	Source
Energy consumption	2.85	kWh/kg	(Grzegorz Pawelec 2020)
Lifetime	20	yr	(Grzegorz Pawelec 2020)
Capex	250	€/kW H2	(Grzegorz Pawelec 2020)
Opex	0.04	%	(Grzegorz Pawelec 2020)

Battery Properties	Value	Unit	Source
Efficiency, from charging plug to propeller	80	%	(DNV GL 2019a)
Gravimetric energy density	77	Wh/kg	(Corvus Energy 2022)
Volumetric energy density	88	Wh/L	(Corvus Energy 2022)
Battery redundancy factor	1.1	kWh/kWh req.	Assumption
Lifetime	15	yr	(Korberg et al. 2021)
CO2-eq emissions	92.4	kg CO2 / kWh installed	(Mats Zackrisson 2017)
Capex SYSTEM	475	€/kWh	(DNV GL 2019a)
Capex only battery	200	€/kW	(Ma et al. 2021)
Opex	6	%	(Lloyd's Register 2019)

Electric Motor Properties	Value	Unit	Source
Capex	250	€/kW	(Korberg et al. 2021)
Opex	1.5	%	(Korberg et al. 2021)
Liftime	30	yrs	(Korberg et al. 2021)

PEM Fuel Cell Properties	Value	Unit	Source
Efficiency SYSTEM	55	%	(Korberg et al. 2021)
Lifetime	60000	h	(DNV GL 2019b)
CO2-eq emissions SYSTEM	31.25	kg CO2 / kW	(Usai et al. 2021)
CO2-eq emissions STACK	22.25	kg CO2 / kW	(Usai et al. 2021)
Capex	1154	€/kW	(Taljegard et al. 2014)
Replacement Capex	250	€/kW	(Grzegorz Pawelec 2020)
Opex	6	%	(Korberg et al. 2021)

ICE Properties	**Value**	**Unit**	**Source**
CTV ICE efficiency	40	%	(Korberg et al. 2021)
SOV ICE efficiency	40	%	(Korberg et al. 2021)
Capex four-stroke	240	€/kW	(Korberg et al. 2021)
Opex	2.5	%	(Korberg et al. 2021)

Charging Bouy Properties	**Value**	**Unit**	**Source**
Lifetime	30	yr	Assumption
Capex	1	M€	Assumption
Opex	5	%	Assumption

Economic Parameters	**Value**	**Unit**	**Source**
Discount Rate	10	%	Assumption
Economic Lifetime	25	years	Assumption

Component costs (capex) used in figure 9 are shown below.

Component	**Value**	**Unit**	**Sources**
PEMEC	1038	[€/kW]	(Schmidt et al. 2017)
	837	[€/kW]	(Schmidt et al. 2017)
	794	[€/kW]	(Schmidt et al. 2017)
	700	[€/kW]	(IRENA 2020)
	700	[€/kW]	(IEA 2021a)
	698	[€/kW]	(Schmidt et al. 2017)
	680	[€/kW]	(Proost 2019)
	670	[€/kW]	(Biggins et al. 2022)
	650	[€/kW]	(Danish Energy Agency 2017)
	600	[€/kW]	(Biggins et al. 2022)
	525	[€/kW]	(IEA 2021a)
AEC	850	[€/kW]	(Proost 2019)
	750	[€/kW]	(Schmidt et al. 2017)
	570	[€/kW]	(Danish Energy Agency 2017)
	560	[€/kW]	(IEA 2021a)
	550	[€/kW]	(Schmidt et al. 2017)
	550	[€/kW]	(Schmidt et al. 2017)
	500	[€/kW]	(IRENA 2020)
	500	[€/kW]	(Schmidt et al. 2017)
	420	[€/kW]	(IEA 2021a)
Compression	250	[€/kW H2]	(Grzegorz Pawelec 2020)
H2 Storage type I	2.49	[€/kWh storage]	(Rivard, Trudeau, and Zaghib 2019b)
H2 Storage type IV	15.4	[€/kWh storage]	(Durbin and Malardier-Jugroot 2013)
	15	[€/kWh storage]	(Karen Law 2011)
PEMFC system	638	€/kW	(Horvath, Fasihi, and Breyer 2018)
	1065	€/kW	(Korberg et al. 2021)
	1154	€/kW	(Taljegard et al. 2014)
	1200	€/kW	(DNV GL 2019a)
PEMFC stack	250	€/kW	(Grzegorz Pawelec 2020)
	280	€/kW	(DNV GL 2019a)
	325	€/kW	(IEA 2021a)
	730	€/kW	(Korberg et al. 2021)
Battery system	600	€/kWh	(DNV GL 2019b)
	475	€/kWh	(DNV GL 2019b)
	200	€/kWh	(Ma et al. 2021)
Battery stack	250	[€/kWh storage]	(Korberg et al. 2021)
	150	[€/kWh storage]	(Lloyd's Register 2019)
ICE	244	€/kW	(Grzegorz Pawelec 2020)
	240	€/kW	(Korberg et al. 2021)
	460	€/kW	(Korberg et al. 2021)
	542	€/kW	(Joanne Ellis and Kim Tanneberger 2015)
	538	€/kW	(Horvath, Fasihi, and Breyer 2018)
Diesel storage	0.09	€/kWh	(Korberg et al. 2021)