Hydrogen Production from Offshore Wind Power in Sweden

A Comparison of Electrolyser System Configurations

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Sammandrag

Den mångsidiga energibäraren vätgas har potentialen att nå sektorer som annars är svåra att avkarbonisera och är också av betydelse för energiomställningen samt att fullt ut avkarbonisera energisystemen. Samtidigt förväntas den havsbaserade vindkraften öka, från vilken stora mängder elektricitet kan produceras. Att använda havsbaserad vindkraft för att förse elektrolysörer med energi möjliggör för en storskalig vätgasproduktion i framtiden. Rapportens syfte är att utföra en tekno-ekonomisk analys av vätgasproduktion från havsbaserad vindkraft i Sverige. Analysen kommer att använda levelised cost of hydrogen (LCOH) som en indikator på kostnadseffektivitet och konkurenskraft. För att uppfylla rapportens syfte, består första delen av analysen av en omfattande litteraturstudie på området, som i andra delen är basen för en platsspecifik fallstudie. Fallstudien är baserad på en hypotetisk vindkraftspark i Sverige på 1100 MW som är kopplad till en vätgasanläggning. All genererad el från vindkraftsparken är dedikerad till vätgasproduktion. En jämförelse av tre olika systemkonfigurationer gällande placeringen av elektrolysörerna utförs: på land, centraliserad till havs samt decentraliserad till havs. Dessutom kommer tre olika teknologier för elektrolys att jämföras: elektrolys med protonbytarmembran (PEM), högtemperaturelektrolys (SOE) och alkalisk elektrolys (AEC). Syftet med jämförelsen är att finna det scenario som är mest konkurrenskraftigt samt genomförbart. Resultaten från analysen visar att den decentraliserade konfigurationen samt AEC elektrolysören är mest konkurrenskraftig. LCOH beräknas till 57–98 SEK/kg H_2, beroende på kombinationen av elektrolysör och konfiguration.

Nyckelord

Vätgas, Elektrolys, Havsbaserad vindkraft, LCOH, PEM, SOE, AEC

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Abstract

The versatile energy carrier hydrogen has the potential to reach otherwise hard-to-abate sectors and is of importance for the energy transition and the full decarbonisation of the energy systems. In the meantime, the offshore wind power is predicted to increase where large amounts of electricity can be produced. Using offshore wind power as an energy supply for water electrolysis enables a large-scale hydrogen production in the future. The aim of this report is to make a techno-economic analysis of hydrogen production from offshore wind power in Sweden. The analysis uses levelised cost of hydrogen (LCOH) as an indicative measurement for determining cost competitiveness. To achieve the purpose, an extensive literature study is conducted from which a site-specific case study is developed. The case study consists of a hypothetical offshore wind farm in Sweden of 1100 MW connected to a hydrogen production facility where all the generated electricity is dedicated to hydrogen production. Three system configurations related to the placement of the electrolyser is compared: onshore, centralised offshore or decentralised. In addition, three different technologies of water electrolysis: Proton exchange membrane electrolyser (PEM), Solid oxide electrolyser (SOE) and Alkaline electrolyser (AEC) are compared. The intention of the comparisons is to find the most cost competitive and viable scenario. The results of the analysis show the decentralised configuration and AEC electrolyser to be the most cost competitive. The LCOH is determined to 57-98 SEK/kg H_2 depending on the combination of electrolyser and configuration.

Keywords

Hydrogen, Electrolysis, Offshore wind power, LCOH, PEM, SOE, AEC

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List of Acronyms

AC alternate current

AEC alkaline water electrolyser

CAD Canadian dollar

CAPEX capital expenditures

DC direct current

DR discount rate

EHB European Hydrogen Backbone

EUR Euro

FV future value

GBP pound sterling

HVAC high voltage alternate current

HVDC high voltage direct current

LCOE levelised cost of electricity

LCOH levelised cost of hydrogen

OPEX operational expenditures

OWF offshore wind farm

O&M operation & maintenance

PEM proton exchange membrane electrolyser

PV present value

RO reverse osmosis

SEK Swedish krona

SOE solid oxide electrolyser

USD US dollar

WRR water recovery rate

WT wind turbine

Symbols

a annum

B boolean

D diameter, cm

e specific energy, kWh/m^3

E energy, kWh

i annual inflation rate, %

IC installed capacity, MW

L length, km

LH lifetime hours

LHV lower heating value, kWh/kg

m mass, kg

N number

OH operational hours

p price, SEK

P power, kW

t time, h

$\boldsymbol{v}$ wind speed, m/s

V volume, m^3

W water consumption, l/kg

η efficiency, %

$\dot{m}$ mass flow rate, kg/h

φ power load, %

Subscripts

ci cut-in

co cut-out

COMP compressor

cons consumption

DEG degradation

DES desalination unit

ELEC electrolyser

EXP export cable

FC fuel cell

FW fresh water

$\mathbf{H_2}$ hydrogen

INT inter-array grid

loss losses

MAX maximum

MIN minimum

r rated

SYS system

TRF transformer

Y year

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1 Introduction

The reliance on fossil fuels for generating energy is, not only causing a rapid depletion of natural resources, but also changing the environmental climate as high quantities of greenhouse gases are emitted. In addition, Russia's invasion of Ukraine has showed the immense dependence of Russian fossil fuels and how the energy security can be affected. The access to clean and renewable energy is of great importance to prevent the climate change from becoming even greater and to meet the growing energy demand.

Hydrogen from renewable sources as an energy carrier is important to be able to fully decarbonise the energy systems. Serving different purposes, such as acting as an energy storage medium, a fuel for transportation or as a feedstock in the metallurgic and chemical industry, it has the potential of reducing emissions in otherwise hard-to-abate sectors. Identifying hydrogen's potential to contribute to the energy transition, the European commission developed an EU Hydrogen strategy that was adopted in 2020 and later in 2021 translated to several legislation proposals through the Fit-for-55 package (European Commission n.d[a]). The strategy has the objective that a minimum of 40 GW water electrolysers producing renewable hydrogen are installed by 2030, with 6 GW installed already by 2024 (European Commission 2020). In May 2022 the ambitions were further raised when the REPowerEU plan was released with the objective to reduce the dependence of Russian fossil fuels. The Hydrogen accelerator, as a part of this plan, is a concept aiming to result in a production of 10 million tonnes and import of 10 million tonnes of hydrogen from renewable sources in the EU by 2030 (European Commission n.d[a]), translating to approximately 65 GW installed capacity of electrolysers (European Commission 2022). One suggested measure to enhance investment security during the scale-up phase is to implement a European hydrogen bank; a global European hydrogen facility which would lead to predictable purchases and sales of renewable hydrogen (European Commission n.d[a]). The EU has defined a product group of renewable fuels named RFNBO, renewable liquid and gaseous fuels of non-biological origin. If renewable hydrogen is produced from renewable electricity fed into an electrolyser, it is considered a RFNBO (European Commission 2023). In addition, Sweden is developing a hydrogen strategy to reflect hydrogen's role in the Swedish target of having net zero emissions by 2045. On behalf of the Swedish government, the Swedish Energy Agency proposed a Swedish Hydrogen strategy in 2021, with the objective to reach 5 GW hydrogen electrolysers installed by 2030 and 15 GW by 2045. This could reduce the emissions by equivalent of 3-6% respective 15-30% of Sweden's current emissions. (Energimyndigheten 2021)

Wind power has experienced a significant growth during the last decade, and the production is expected to increase even more. The IEA predicts wind to be the primary power source in Europe by 2027 (WindEurope 2023) and the aim from the EU is to reach an installed capacity of offshore wind power of 60 GW by 2030 (European Commission n.d[b]). When increasing the production from wind power, challenges arises, such as grid reinforcements and the problem of intermittency, the fact that wind is not predictable and constantly available, which leads to difficulties maintaining the supply and demand grid balance (WindEurope 2023). To manage these challenges, coupling the offshore wind power production with water electrolysis, using renewable energy to produce hydrogen, is a promising solution (Singlitico et al. 2021). The produced hydrogen may be used for energy storage and converted, through a fuel cell, into electricity when needed to restore the supply and demand balance and provide an ancillary service. From another perspective, great amounts of energy can be produced from offshore wind power enabling for a large-scale hydrogen production. Although offshore wind power is a renewable power source, the supply of electricity is more stable compared to other intermittent renewable sources, such as onshore wind and solar power, as the wind speed usually is higher and less fluctuating (Li et al. 2020).

Despite that renewable hydrogen is arising as a promising part towards an energy transition, both fossil-free and with high energy security, the deployment of hydrogen faces several challenges. One of the great challenges is the current high price of hydrogen production from renewable sources compared to fossil sources. To assess the future viability of large-scale offshore wind-to-hydrogen production plants in Sweden, an investigation of the cost competitiveness is motivated.

1.1 Aim

The aim of this work is to make a techno-economic analysis of hydrogen production from offshore wind power. The levelised cost of hydrogen (LCOH) will be determined through which the cost competitiveness as well as opportunities and limitations will be assessed. A literature study will be performed from which a case study in this research field will be developed. The case study will concern a specific site in Sweden with an hypothetical off-grid, offshore wind-hydrogen system, where all the generated electricity is dedicated to hydrogen production. A comparison between three alternative configurations of the electrolysis system as well as three different electrolyser technologies will be conducted in the study. To achieve the aim, the study will be based on the following research questions:

- Which of the electrolyser configurations is more cost competitive: onshore, centralised offshore or decentralised offshore?
- Which of the electrolyser technologies is more cost competitive: Proton exchange membrane, Solid oxide or Alkaline water electrolyser?
- Which are the main parameters affecting the profitability?

1.2 Delimitations

The production plant is assumed to be in operation by 2030, thus prices and technology development for the specific year are considered. Social and environmental analyses will be kept outside the scope of this work due to complex quantifications needed for a comparison of the different scenarios. The storage and usage of the produced hydrogen are also considered to be outside the scope.

1.3 Structure

Chapter 2 presents the background to the various topics related, chapter 3 consists of a literature review where previous research is presented. Chapter 4 includes the case study and the methodology used to answer the research questions. The results are presented in chapter 5, and further discussed and analysed in chapter 6, which also includes a sensitivity analysis. Finally, conclusions are presented in chapter 7 together with proposed further research.

2 Background

This chapter covers the relevant background and gathers information about the current situation of offshore wind power, hydrogen and electrolyser technologies. Moreover, the system components for an offshore wind power-electrolyser system are described.

2.1 Offshore Wind Power

Offshore wind power has several advantages compared to wind farms located onshore. The offshore turbines can be scaled much larger seeing that there is more available space at sea and less limitation in height. Moreover, wind speeds at sea are usually higher with a more consistent direction, allowing more energy to be generated per amount of capacity installed. Additionally, the location of the wind farms is less intrusive when at sea as they do not interfere with land usage or neighboring countries or cities. However, other stakeholders are affected and other challenges arise when building offshore, such as interference with the national defense, shipping routes or commercial fishing. The offshore wind farms (OWF) are more difficult to access making installation and maintenance more challenging and repairs lengthy as well as more expensive.

Currently, wind power makes up about 17% of the total electricity production in Sweden. The installed capacity is around 12 GW which contributes to a production of approximately 27 TWh, distributed between the different electricity areas in the country (Energimyndigheten 2022). The production is expected to increase in the future although some obstacles must be fought, such as local resistance and long lead times in the permitting process. The willingness of investing in offshore wind power can be seen in the numerous on-going project developments. An area of interest is along the coast of southern Sweden, as illustrated in figure 1. In 2020 the European Commission published an offshore renewable energy strategy, with the aim of reaching an installed capacity of at least 60 GW offshore wind by 2030 and 300 GW by 2050 (European Commission n.d[b]). The Commission estimates this scenario to be realistic and achievable which would contribute to major benefits in terms of decarbonisation in several sectors, job opportunities and providing cleaner energy in line with the European Union's Fit-for-55 package.

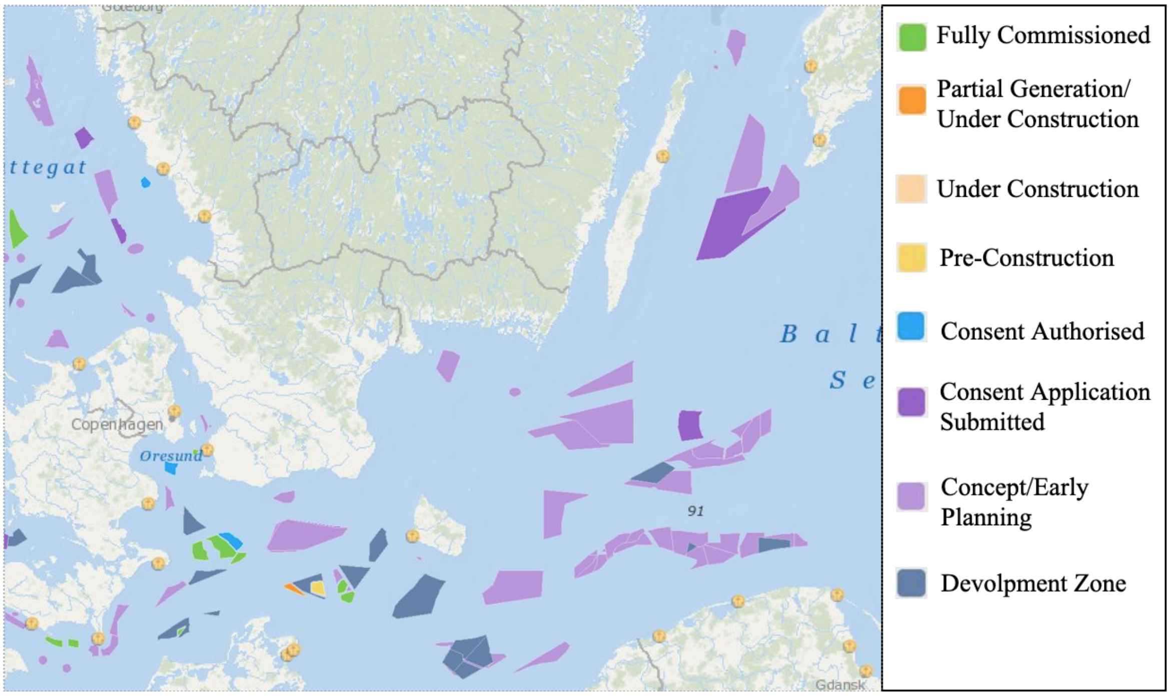


Figure 1: Map over projected and existing areas for wind farms in southern Sweden, Denmark, Germany and Poland (4C Offshore 2023).

2.1.1 Future Outlook

In recent decades, turbine sizes have increased rapidly. In 2018, wind turbines of between 3.5 MW up to 10 MW capacity, with a rotor diameter of around 160 meters were being deployed (IRENA 2019). The technology keeps improving and the offshore turbines in 2030 are expected to have a rated capacity of up to 20 MW with rotor diameters of larger than 230 meters and a total height of 300 meters (IRENA 2019).

With the increasing size of the turbines, capital expenditures (CAPEX) per MW is likely to increase, but the future turbines allow for lower operation and maintenance (O&M) costs as well as lower costs of energy seeing that the energy production is higher and CAPEX for foundations and installation will be lower. The growth in turbine size also helps to increase the capacity factor. In 2018, the weighted average capacity factor was at 43% and is expected to be in the range of 36% to 58% in 2030 (IRENA 2019). When all these parameters are taken into account, predictions show the LCOE for offshore wind will globally reach a range of 0.52 to 0.94 SEK/kWh by 2030, compared to 1.32 SEK/kWh in 2018 (IRENA 2019).

2.2 Hydrogen

Hydrogen is the lightest and most abundant element on earth, but can not be mined as a resource directly as it is mostly occurring in bonded form, primarily as water. (Fan et al. 2021). It has a very high specific energy (120 MJ/kg) compared to other common fuels as for example gasoline (47.3 MJ/kg). However, due to hydrogen's low density (0.09 kg/m^3) the energy density is exceptionally low (10 MJ/m^3). (Sundén 2019) Under normal condition, hydrogen is in gaseous state, with a boiling point of -252.9 °C, and is colour-, odour- and tasteless (Tahan 2022). Hydrogen is not toxic, corrosive or self-igniting (Adam et al. 2020).

Hydrogen is not an energy source itself, but can be used as a versatile energy carrier due to its high specific energy. Hydrogen is flammable and can be burnt to water vapour without emitting CO_2 (Adam et al. 2020). Useful energy can be generated from hydrogen gas, either used as a fuel and be burnt in high temperature in a furnace, boiler or turbine or be converted electrochemically to electricity or lower-grade heat in a fuel cell (Fan et al. 2021).

Production

Hydrogen can be produced by several production methods. About 70% of dedicated hydrogen production in 2021 was produced by steam methane reforming (SMR) using natural gas (IEA 2022b). The principle of SMR is a reaction of hydrocarbons, usually natural gas, with water steam, producing syngas – hydrogen and carbon monoxide. In a second step the syngas is upgraded, where the carbon monoxide is reacted with steam, producing more hydrogen with carbon dioxide as a by-product. (Speight 2020) Another common method, dominating in China, is coal gasification (Fan et al. 2021). Around 30% of the globally dedicated hydrogen production in 2021 was met with coal. (IEA 2019a) Similar to SMR, syngas is produced as steam and oxygen breaks molecular bonds in the coal. The syngas is upgraded, resulting in CO_2 as a by-product. (IEA 2022a) The method that enables hydrogen production without the use of fossil fuels is electrolysis, using electricity to split water into hydrogen and oxygen. However, the origin of the electricity will affect the life cycle emissions of the production. Less than 0.1% of the global hydrogen was 2021 produced by electrolysis (IEA 2022a). However, the installed capacity of electrolysers is expanding rapidly. In 2021, 210 MW electrolysis capacity was installed, reaching a level of 510 MW installed capacity (ibid). In addition to dedicated hydrogen production, over a sixth of the global hydrogen supply is produced as a by-product, mainly from the petrochemical industry (IEA 2022b).

Transportation

Because of the low molecular weight, it can be challenging to transport and store hydrogen. The risk of leakage is relatively high due to the low density. Generally, the hydrogen must be liquefied at very low temperatures, compressed to high pressures or stored in porous materials (Fan et al. 2021).

There are different options for transporting and distributing hydrogen. This is mainly done by using pipelines and on a smaller scale; trucks, trains or ships (Fan et al. 2021). Transporting via pipeline is generally cost competitive up to distances of 5000 km (IEA 2022b). Plans for hydrogen pipelines are currently being developed, where one initiative is at the forefront, the European Hydrogen Backbone (EHB). EHB is a group consisting of 31 European energy infrastructure operators with the common vision to establish a pan-European infrastructure for hydrogen. The network can reach a length of almost 53 000 km by 2040, where repurposed existing natural gas infrastructure will constitute the largest part of the network (Rossum et al. 2022).

When distances exceed 5000 km, shipping and hydrogen carriers become more cost competitive (IEA 2022b). As recently as February 2022, the first shipment of liquefied hydrogen took place where 75 tonnes were transported from Australia to Japan (IEA 2022b). This way of transportation is expected to increase in scale by the end of the decade. However, liquefying requires extremely low temperature which makes transportation over long distances costly and challenging. Further development of distributing and transporting hydrogen is therefore needed.

The hydrogen can also be converted to several derivatives to reach its full potential. When hydrogen is combined with carbon from CO_2, hydrocarbons are produced. It can also be used in the production of methanol and synthetic fuels. Furthermore, hydrogen may be used to produce ammonia which later can be used as feedstock for fertilisers. Once converted to these derivatives, the energy density is increased enabling long-term storage and long-distance transportation to become more cost effective (IEA 2022b).

End Use

Hydrogen as an energy carrier has many fields of use. In 2021 the hydrogen demand reached 94 million tonnes, equal to about 2.5% of the global final energy consumption (IEA 2022a). The majority of the hydrogen today is used in oil refining, ammonia- and methanol production and the overall chemical industry. However, with the need to reduce carbon emissions, hydrogen has started being used in fields like production of steel, with the potential to also be used in concrete production. Usage of hydrogen is, and will increasingly be, present in the transport sector where it functions as fuel, directly or as a derivative, in shipping, aviation, trucks, cars etc. Ship refueling has the potential of being completed directly at sea when the hydrogen production is located offshore. Seeing that a fraction of hydrogen can be blended into the gas grid, it can also be used for heating residential and commercial buildings, leading to the future potential of reducing the use of natural gas. Moreover, hydrogen can be used in fuel cells to produce electricity which enables electricity generated from renewable sources to be stored as hydrogen and converted back to electricity when needed, and thereby providing flexibility to the grid. (IRENA n.d)

In Sweden, hydrogen is mainly used in the chemical and refinery industry, around 180 000 tonnes corresponding to 6 TWh/year, and is produced from fossil fuels (Energimyndigheten 2021). The majority of the produced hydrogen is used close to the production facility seeing that the gas grid in Sweden is limited and dedicated to transportation of natural gas from Denmark to industries in southern Sweden. Merely, small quantities are being transported to customers, either compressed in gas tubes or in liquid form via tank trucks.

2.2.1 Electrolyser Technologies

The demand of hydrogen production using renewable sources is increasing rapidly and is also the focus of this work. Electrolysis technologies are therefore further described in this section.

Hydrogen is produced using electricity to split water molecules into hydrogen and oxygen in an electrochemical device called a water electrolyser. The water electrolyser can be divided in three different levels: cell, stack and system. The cell is the core of the electrolyser where the actual electrochemical process takes place. It consists of two electrodes, an electrolyte (either liquid or solid), two porous transport layers favouring the removal of products and transportation of reactants, and the bipolar plates providing mechanical support. Broadening the scope, the stack is the next level consisting of multiple cells which are connected in series. Moreover, various other elements are included to facilitate support, insulation, collection of fluids and avoidance of leakage. The last level is the system which includes the equipment for cooling and processing the hydrogen with purification and compression. Additionally, components for converting the supplied electricity such as transformers and rectifiers are included, as well as, deionisation units for water treatment. (IRENA 2020)

The principle of water electrolysis is simple, purified water is fed into the system flowing through the bipolar plates and the porous transport layers to reach the electrodes where water is split into hydrogen and oxygen. This is done by ions crossing through the electrolyte, which also helps separating the produced hydrogen and oxygen gases avoiding their mixture. However, the principle allows for different technological approaches based on various physical and electrochemical aspects. The technologies of the electrolysers varies in operating temperature, electrolytes, materials and components. Proton exchange membrane, alkaline and solid oxide water electrolysers are three of the currently existing types. These three will be described more thoroughly in the following section. (IRENA 2020)

Proton Exchange Membrane Water Electrolyser (PEM)

In a proton exchange membrane electrolyser, the electrolyte consists of a solid plastic material. This technology is also known as polymer electrolyte membrane electrolysis. The electrolysis process is injected with deionised water without any electrolytic additives (Wang et al. 2022). When water reacts at the anode, oxygen as well as positively charged ions are formed. Electrons are supplied via an external circuit and the hydrogen ions move across the membrane to the cathode. Hydrogen ions are then combined with the electrons from the external circuit. This reaction occurs at the cathode and hydrogen gas is produced (Sundén 2019), the schematic of a PEM cell is shown in figure 2. The electrodes consists of noble metals like iridium oxide and platinum (Brauns and Turek 2020) which leads to a higher CAPEX for this technology compared to others. The used electrolyte is a humidified polymer membrane. The half reactions for the PEM are the following (Shiva Kumar and Himabindu 2019).

$$\text{Anode :} \qquad H_2O \rightarrow 2H^+ + \frac{1}{2}O_2 + 2e^- \tag{I}$$

$$\text{Cathode :} \qquad 2H^+ + 2e^- \rightarrow H_2 \tag{II}$$

PEMs have several advantages compared to other technologies such as higher current densities leading to a smaller footprint, faster start-up times, higher hydrogen purity, higher output pressure and operation beyond nominal power (Calado and Castro 2021). The ability to easily adjust power to match the conditions and a fast start-up time allows the PEM to extract the most out of intermittent power sources. When shutdown occurs, maintenance of the system operation requires low amounts of energy which is of importance when the electrolyser is located offshore and off-grid. During these conditions, a backup power source is also required seeing that necessary energy during shutdown periods is not guaranteed. (Calado and Castro 2021)

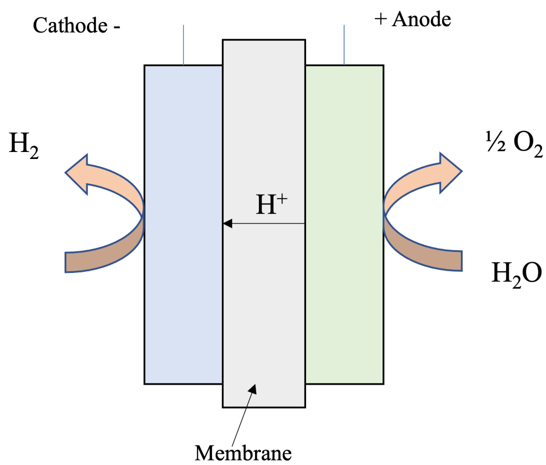


Figure 2: Illustration of a PEM cell.

Alkaline Water Electrolyser (AEC)

Hydrogen production by alkaline water electrolyser is a mature technology which is being used at commercial level in the megawatt range. At the anode, hydroxide ions are oxidised to oxygen and water while releasing electrons whereas at the cathode, water is reduced by electrons to hydrogen and negatively charged hydroxide ions. The electrodes consists of non-noble metals such as nickel with an electrocatalytic coating and the electrolyte is a concentrated lye (Brauns and Turek 2020). Moreover, the electrolyser requires a gas-impermeable separator to prevent the produced gases from mixing. An illustration of an AEC cell can be found in figure 3. The chemical reactions for this process are presented below (Shiva Kumar and Himabindu 2019).

$$\text{Anode :} \qquad 2OH^- \rightarrow H_2O + \frac{1}{2}O_2 + 2e^- \tag{III}$$

$$\text{Cathode :} \qquad 2H_2O + 2e^- \rightarrow H_2 + 2OH^- \tag{IV}$$

Seeing that AEC is such a mature technology, the investment costs are relatively low, compared to other technologies. Additionally, the lifetime is longer and the annual costs for maintenance are lower than for a PEM system (Brauns and Turek 2020). However, if the AEC should ensure high efficiency and safety, the electrolysers must be optimised for dynamic operation.

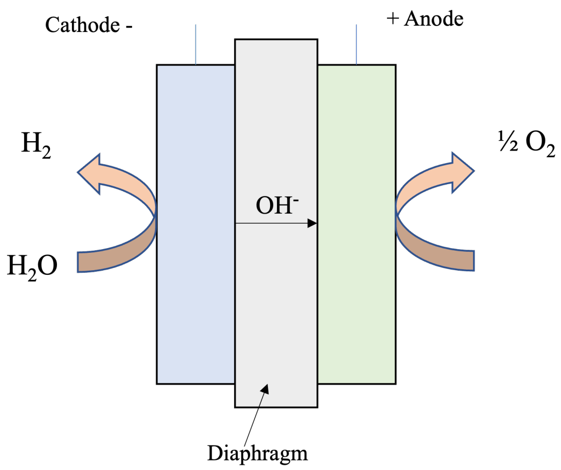


Figure 3: Illustration of an AEC cell.

Solid Oxide Electrolyser (SOE)

The most recent technology of the previously described is the solid oxide electrolysis. Currently, it is rarely used in commercial applications due to low durability and high operating temperatures, usually above 800 °C (Davies et al. 2021). The high temperature is needed as gaseous water is converted into hydrogen and oxygen with the use of a solid oxide, or ceramic electrolyte. However, the temperature is a disadvantage when coupled with intermittent power sources and causes degradation of the used materials. This electrolyser promises better efficiency than other technologies. Moreover, it does not require any noble metals, as PEM does, making it possible to reach lower CAPEX when the technology has matured (Calado and Castro 2021). The SOE is also able to operate reversibly as a fuel cell without the need of any additional components. The schematic of a SOE cell is shown in figure 4 and the half reactions for the process can be found below (Shiva Kumar and Himabindu 2019).

$$\text{Anode}: \qquad O^{2-} \rightarrow \frac{1}{2}O_2 + 2e^- \tag{V}$$

$$\text{Cathode}: \qquad H_2O + 2e^- \rightarrow H_2 + O^{2-} \tag{VI}$$

As the demand for efficient energy conversion technologies increases, the use of SOE will increase, which will help reduce production costs for the electrolyser. The cost competitiveness of the SOE is thus anticipated to increase in the future.

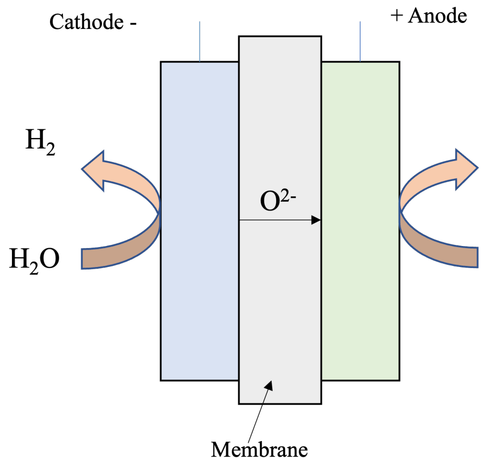


Figure 4: Illustration of a SOE cell.

2.2.2 Costs of Hydrogen Production from Water Electrolysis

A competitive production cost of renewable hydrogen production is of importance to reach set goals within Sweden and EU. The production cost for hydrogen from electrolysis depend on several factors where electricity cost and the electrolysis facility cost are the dominant components (IRENA 2020). Around 50-60% of the CAPEX can be derived to the electrolyser stack (IEA 2019a). Conversion efficiency and operating hours are also of great impact to the production cost (IEA 2019a).

Analysis by IEA (2019a) suggest that a cost reduction of 30% for renewable hydrogen production is possible until 2030 as a result of lower prices of renewable electricity and lower investment costs due to up-scaling. Another prediction by IRENA (2020) is cost reductions up to 80% of renewable hydrogen production by 2050, using strategies leading to cost reductions in renewable electricity and investment cost, in combination with improved electrolyser efficiency and operating life time (IRENA 2020).

2.2.3 System Components

Besides the electrolysers, several other components are required in an offshore wind-hydrogen system, which are briefly described below. The required components may vary between the system configurations. Three alternative system configurations when producing hydrogen from offshore wind power are having the electrolyser placed onshore, centrally placed offshore on a platform or decentrally placed offshore next to or in each individual turbine. Table 1 shows the associated components to the respective configuration based on the scope and assumptions of this work. Required components could however vary within configurations as well, depending on the design of the system.

Table 1: Components present in each configuration.

Component	Configuration		
	Onshore	Centralised offshore	Decentralised offshore
Deionisation unit	x	x	x
Desalination unit		x	x
Transformer	x		
Inter-array cables	x	x	
Export cable	x		
Compressor	x	x	x
Hydrogen pipelines		x	x
Backup power source	x	x	x

Deionisation Unit

Water electrolysis requires high purity water. For every kilogram of hydrogen produced, stoichiometrically 9 kg of purified water is consumed. The feeds are achieved by water purification systems which can be either external pre-treatment plants or an internal incorporated system in the electrolysis system. (Tong et al. 2020)

Desalination Unit

If the water source for the water electrolysis will be seawater, a desalination plant is required. Direct use of seawater could namely lead to a competing chlorine evolution reaction at the anode. In addition to chlorine production, seawater can lead to corrosive damage. (Tong et al. 2020) There are several existing technologies for desalination, which can be categorized as thermal or membrane processes (Lamagna et al. 2022). The dominating technology is reverse osmosis (RO), a membrane and electricity-driven process, due to its high electric efficiency and flexibility (Ibrahim et al. 2022). The principle of RO is that by applying pressure higher than the salt water's osmotic pressure, water molecules are transported through a semipermeable membrane while salt ions are rejected (Suss et al. 2022), illustrated in figure 5.

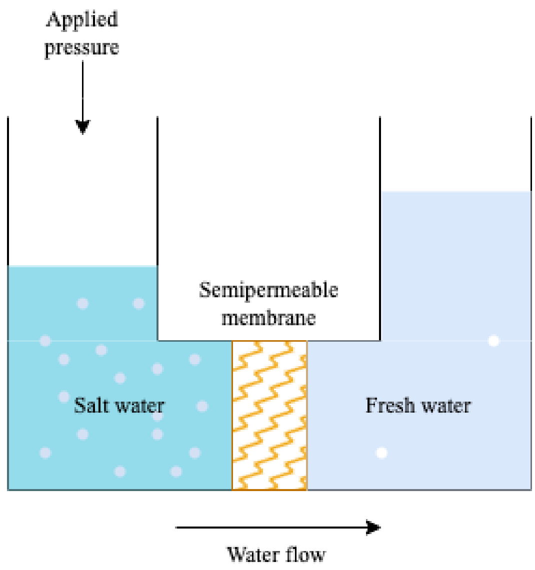


Figure 5: Illustration of a RO filtration.

The water recovery rate (WRR) for existing state-of-the-art RO is around 50%, meaning that the permeate water flow is 50% of the feed water flow. The input water feed would thus be around twice the stoichiometrically need. (Beswick et al. 2021; Lamagna et al. 2022) The electricity consumption of state-of-the-art seawater RO is about 2-4 kWh/m^3 produced desalinated water (Zhao et al. 2021).

Inter-array Cables

The purpose of the inter-array cables is to link the individual wind turbines to the substation at sea. Inter-array cables are typically alternating current, three-core copper conductors with steel wire armoured and insulation components (Srinil 2016). These cables are called cross-linked polyethylene cables, or XLPE cables. Traditionally, the nominal operating voltage is 33 kV thus the 33 kV-cables have been standard practice to use. However, as the turbines develop and the wind farms becomes larger, the 66 kV-cables with smaller cross-section and lower current are currently more common. These cables allow for greater power capacity and reduce the system power losses (Srinil 2016). Usually, four to five turbines are connected to one cable string within the farm resulting in a great amount of cables in a large offshore wind farm (OWF).

Transformer

Traditionally, the demand is located at farther distances from the generation plants. Thus, voltage needs to be extensively increased in order to transmit large volumes of power over long distances. The main purpose of a transformer is to change the voltage. In an OWF, the turbines are connected, via cables, to a transformer with the objective to increase the voltage. When this is done, losses are substantially reduced and transmission capacity is increased. Furthermore, the requirements for aluminum and copper are reduced. (Das and Cutululis 2017)

Export Cable

The export cable transports the generated electricity from the substation to the cable connection facility point on shore. The key function of the export cable is to efficiently transmit the power while minimising the losses. The cables are able to operate with high voltage direct current (HVDC) (single core) or high voltage alternate current (HVAC) (single- or three core), mostly depending on the distance from the wind farm at sea to shore, and the operational costs together with the total generated power of the wind farm. The break-even between HVAC and HVDC is around 100 km due to increments in costs and harmonic resistance for long distances with alternate current (AC) power transmission (Groenemans et al. 2022). HVDC cables require both offshore and onshore converter stations where the construction of an offshore converter is relatively costly. However, these cables have greater advantages when considering larger amount of transmitted power over long distances. This is due to reduction in losses when comparing to HVAC cables. For HVDC cables, the initial costs are greater due to the need of converters, however, the increment in expenses are lower along the distance than for HVAC cables (Srinil 2016). The cables, especially the export cables, are one of the components within an offshore wind farm that have the greatest influence on the total cost. Thus the model of cables and the layout of the internal grid need to be carefully selected and designed.

Compressor

Prior to transportation of hydrogen in pipelines, compression of the gas is needed. Due to hydrogen's physical properties, the low molecular weight and low density, the compression process requires more stages and energy to reach a certain discharge pressure compared to e.g. natural gas (Adam et al. 2021).

There are two compression methods mainly used for hydrogen compression: reciprocating and centrifugal compressors (Tahan 2022). Reciprocating compressors has an efficiency advantage with lower leakage for low molecular weight gases like hydrogen compared to the centrifugal ones. In general, centrifugal compressors are better suited for high volume flows with a relatively low pressure required whereas reciprocating are more often used when lower volume flows but higher pressures are needed (Adam et al. 2021).

Hydrogen Pipelines

Hydrogen pipelines are necessary in the system for transportation to shore when the production of hydrogen occurs at sea. A typical pressure for transporting hydrogen in pipelines is 70 bar (IRENA 2020). However, over the length of the pipe, pressure drop occurs. A typical North Sea pipeline is expected to experience a pressure drop of 3-10 bar/100 km, but values as high as 25 bar/100 km can occur (Ibrahim et al. 2022). Consequently, hydrogen must be well pressurised in order to compensate for the drop over the travelled distance, although pressure increments also enhances the risk for embrittlement. Studies have shown that pipelines suffers significantly lower losses, under 0.1%, compared to HVAC transmission with losses between 1-5% and HVDC with losses between 2-4%, depending on nominal power and distance (Calado and Castro 2021). One of the main challenges with hydrogen pipelines compared to cables, are the maintenance. The pipelines need to be cleaned to remove accumulated condensates in the interior, leading to higher operating expenditures (OPEX). Furthermore, repairing pipelines when malfunctioning or broken, are more costly and challenging (Ibrahim et al. 2022).

Backup Power Source

A backup power source must be provided for the electrolyser when coupled with a renewable, intermittent power source, and for the wind farm when not connected to the grid. During periods of energy shortage, the electrolyser still consumes a small amount of power in order to remain in stand-by mode instead of being turned off. If turned off, additional energy is required for a start. The auxiliary equipment in the wind farm is also consuming electricity when standing still. The purpose of the backup power source is to provide enough energy for the systems when there is not enough energy generated by the wind farm. The backup power source can for instance be a fuel cell, or a battery powered with generated electricity from the wind turbines. (Calado and Castro 2021)

3 Previous Research

In the following chapter, information from previous research will be presented. A comprehensive literature study has been made with the aim to provide details and identify gaps, to be able to expand knowledge and contribute to the research field. All the currencies presented are converted according to the exchange rate for 29 March 2023 where 1 EUR equals 11.22 SEK (ECB 2023), 1 USD equals 10.39 SEK (Di 2023a), 1 CAD equals 7.74 SEK (Di 2023c) and 1 GBP equals 12.82 SEK (Di 2023b).

3.1 Examples of LCOH Results from Previously Performed Analyses

The potential of hydrogen production using electricity sourced from offshore wind power is a field that is currently given a lot of attention due to its potential, which is reflected in a numerous amount of recent studies in this field. The measurement LCOH is commonly found among the studies, as it functions as an indicator of the profitability and cost competitiveness of the hydrogen of interest. A literature study within this research area has been conducted to use as a basis when in this report developing a relevant case study. Table 2 summarises several new techno-economic analyses, presenting calculated values of LCOH along with technical parameters considered. Configurations relate to the placement of the electrolyser which can be onshore, centralised offshore (placed on an offshore platform) or decentralised offshore (placed next to or in each individual turbine).

Table 2: Summary of the literature study within the examined field.

Source	LCOH (SEK/kg H_2)	Electrolyser	Configurations	Grid connection	OWF capacity	Case specific
(Vu Dinh et al. 2023)	<44.88	PEM	Centralised	No	510 MW	Water depth, distance to port, 3 types of foundations
(Jang et al. 2022)	143.49 - 151.49	PEM	Onshore, centralised, decentralised	No	160 MW	Floating foundations
(Singlitico et al. 2021)	min. 26.93	PEM, AEC, SOE	Onshore, centralised, decentralised	Yes	12 GW	Hydrogen-driven or electricity driven, energy island
(Kim et al. 2023)	17.04 - 46.34	PEM, AEC, SOE	Onshore, centralised	Yes	400 MW	Varying wind speed, distance to shore
(Nguyen Ding et al. 2021)	56.10	PEM	Centralised	No	101.3 MW	Underground storage
(Armiño Franco et al. 2021)	24.35 - 74.73	PEM	Onshore, centralised	No	100 MW	Different hydrogen transportation pathways
(Groenemans et al. 2022)	21.72 - 38.24	PEM	Onshore, decentralised	No	600 MW	

The literature study shows a considerable variation between the LCOH results. Different conditions, such as system capacities, wind data and system lifetime, will affect the outcome. It is thus of interest to understand the different assumptions, conditions and considerations used in the research when comparing the results. Table 2 display what type of electrolyser technology and system configuration is considered, if the system is grid connected or off-grid, the installed capacity of the wind farm as well as other distinguishing, case specific considerations.

Where the LCOH, in table 2, constitutes of large ranges, several variables are present resulting in comprehensive analysis with multiple combinations. A certain correlation between the OWF capacity and LCOH is identified. However, several parameters may affect the results leading to difficulties to distinguish the exact reasons for the differences.

Several of the studies have compared different system configurations. Jang et al. (2022) and Singlitico et al. (2021), both comparing three configurations, have differing conclusions. Jang et al. (2022) found the decentralised offshore configuration to result in the lowest LCOH, followed by centralised offshore, whereas Singlitico et al. (2021) found centralised offshore to have the lowest LCOH, followed by the onshore configuration. According to Armiño Franco et al. (2021) and Groenemans et al. (2022), the most cost competitive configuration was found to be the offshore centralised and decentralised respectively, in contrast to the onshore configuration found by Kim et al. (2023). Kim et al. (2023) and Singlitico et al. (2021) compared electrolyser technologies as well, both concluding that AEC has the lowest LCOH due to the technology being mature. However, Singlitico et al. (2021) identifies the differences to be almost negligible in comparison to PEM and SOE.

Whether the system is on-grid or off-grid has an influence on the LCOH. If a grid connection exists, the supply of electricity to turbines and/or electrolysers during maintenance and shut-down periods, is secured. Moreover, the grid connection enables the electrolysers to have a lower capacity without loosing any electricity as the excess can be transmitted to the grid and may be sold on the ancillary service market. When on-grid, a fee for the grid connection needs to be taken into account as well as the need for both cables and pipelines for transmission and connection of the system to shore. This might be disadvantageous for the offshore configurations. An advantage with having the system off-grid is that it enables the project to be located where grid connection is not plausible, e.g. if transmission congestion is a limitation.

In table 2, Jang et al. (2022) shows LCOH values significantly higher than other values presented. This is identified to mainly be due to the floating foundations having a higher CAPEX and the installed capacity of the OWF being noticeably low. Moreover, decommissioning is also included. They concluded that the offshore wind farm-hydrogen system is only profitable if an existing wind farm is used, as the CAPEX for the turbines and foundations may be deducted from the LCOH (Jang et al. 2022). The analysis Singlitico et al. (2021) made was modeled through two operation modes, either hydrogen-driven where the generated electricity primarily is used to cover the nominal capacity of the electrolyser and the excess electricity is transmitted to shore, or electricity-driven where the electricity generated is primarily used to cover the electricity demand, the electrolyser only using the excess electricity. The system has an exceptionally higher OWF capacity compared to other research investigated, which is influencing the LCOH. Hydrogen-driven operation of the system achieved the lowest LCOH.

Based on the literature study, the case study of this report was decided to both compare three different electrolyser technologies and three different system configurations, operating off-grid, as this was not found to have been examined previously. The study will also be site-specific, considering Swedish conditions. Producing hydrogen from renewable sources is desirable and of importance for the future energy systems, where the cost competitiveness will be an essential factor to reach the targets set by the EU and Sweden. Evaluating the future cost competitiveness of feasible methods when producing hydrogen from offshore wind power in Sweden is thus believed to add value to the industry and the field of research.

4 Methodology

The following chapter explains the methodology of the work. It also contains a description of the wind farm and the decided system configurations. Furthermore, production calculations with corresponding assumptions and equations are presented. More specific assumptions for certain calculations are declared in the associated subsection.

4.1 Case Description

A techno-economic analysis has been conducted with the aim to determine the levelised cost of energy and the levelised cost of hydrogen. The hypothetical wind farm is expected to start operating in 2030 due to time required for permit processes and construction. Therefore, the analysis was based on the year of 2030 with regards to technology development and cost trends when possible. Cost data for different components were collected from academic sources where some modifications, such as currency conversion, were necessary in order to criticise the sources and compare the found data. Predictions and assumptions have been made with the attempt to reflect the market of that year.

4.1.1 Scope

The scope of the techno-economic analysis was determined to include the wind farm with corresponding electricity production, transportation of the electricity to the chosen electrolyser for hydrogen production. In the onshore configuration, a transformer is needed for the electricity to reach shore. Furthermore, the compression and the pipeline to transport the hydrogen to shore was included. The latter is only applicable for the centralised and decentralised configurations, i.e. when the electrolyser is placed offshore. The storage and the end use of hydrogen was defined out of the scope, mainly due to complexities and limitations in time and information. The scope is illustrated in figure 6.

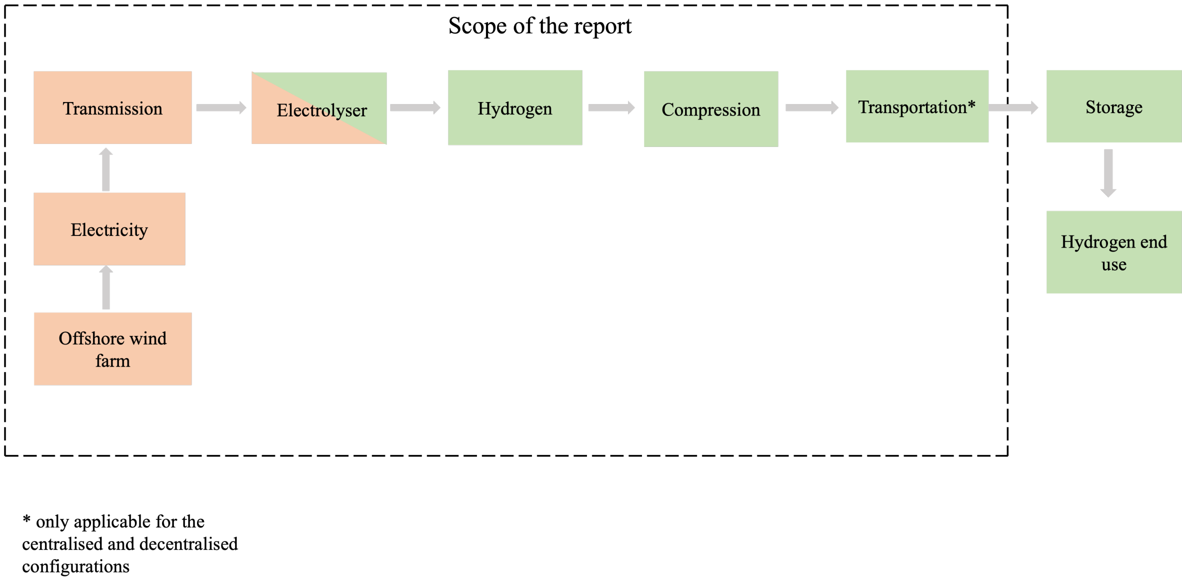


Figure 6: Illustration of the scope of the report. The orange represents electricity flows whereas the green represents hydrogen flows. The boxes inside of the dotted lines are considered to be within the scope.

4.1.2 Description of the Offshore Wind Farm

This work considers future hydrogen production integrated with offshore wind power in Sweden. The case studied will be a hydrogen production facility connected to a hypothetical offshore wind farm. The investigated area is located in the Baltic sea outside the Swedish coast, with the nearest shore about 25 km from the outer edge of the wind farm and an average wind speed of about 10 m/s at 150 m.

The layout of the OWF that will be considered in this work includes 55 wind turbines with an installed capacity of 20 MW, resulting in a total capacity of 1100 MW. The turbines are assumed to have a rotor diameter of 260 m, a hub height of 160 m and a lifetime of 35 years.

4.1.3 System Configurations

In this analysis it is assumed that all of the generated electricity from the OWF is dedicated to hydrogen production. The system will not be connected to the electricity grid and thus the related services will be operated only by the electrical output from the OWF or the backup power source.

Three electrolyser system configurations for this proposed offshore wind energy integrated hydrogen production will be evaluated technically and economically: onshore (case 1), centralised offshore (case 2) and decentralised offshore (case 3) (figure 7). The details of the configurations considered in this work are described in this section.

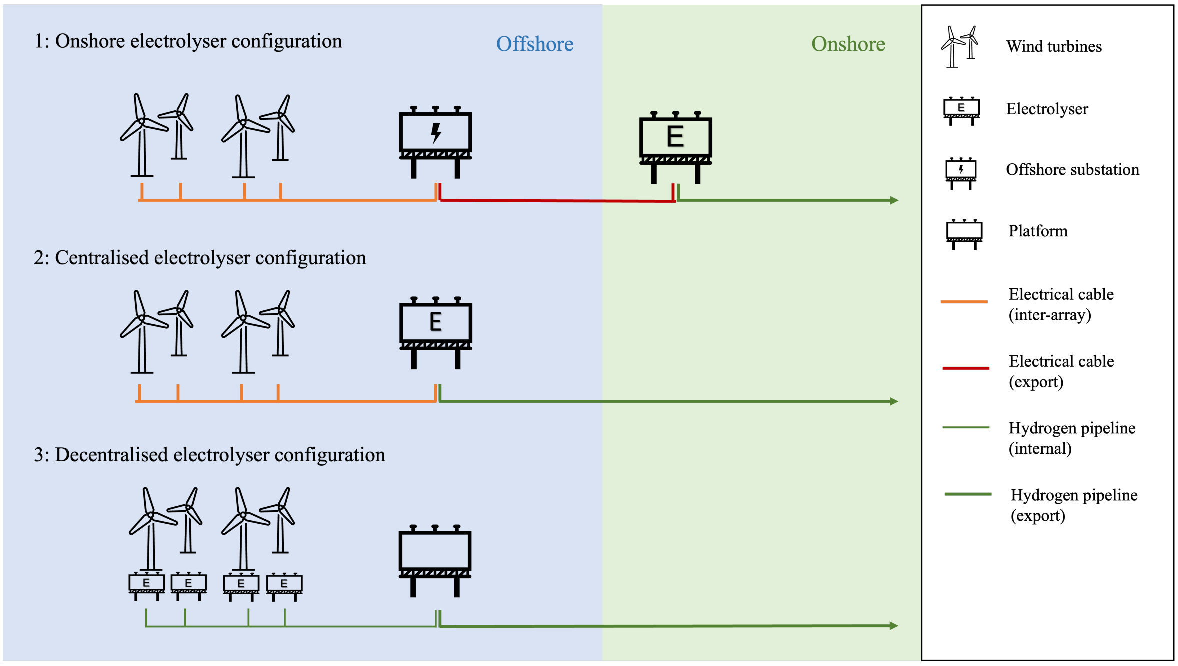


Figure 7: Schematic representation of three possible placements of the electrolyser in offshore wind-hydrogen systems.

Case 1: Onshore

In the onshore electrolysis system alternative, the electricity produced by all wind turbines in the OWF is transferred to two central offshore substations located inside the wind farm area through inter-array cables (66 kV) where the electricity is transformed and transmitted to the electrolyser at shore by HVAC export cables (400 kV). The electricity not used to power the compressor is used for hydrogen production. As the system is off-grid, an alkaline fuel cell is acting as a backup power source in connection to the electrolyser. The produced hydrogen is then compressed to grid pressure (70 bar) and if needed, re-filling the storage tank related to the fuel cell. As the electrolysis is conducted onshore, freshwater can be used and thus is a desalination system not necessary.

Case 2: Centralised Offshore

In the centralised offshore electrolysis scenario, the electricity produced in the OWF is transmitted via inter-array cables (66 kV) to an offshore platform within the wind farm area, hosting the electrolyser system. As the water source is seawater, desalination is needed prior to the electrolysis. In addition to the desalination unit and electrolyser, the platform hosts a hydrogen compressor. At the platform, the excess electricity that is not used to power the desalination unit and hydrogen compressor is used to produce hydrogen. The platform is also hosting an alkaline fuel cell as a backup power source. The hydrogen produced is then compressed and either re-filling the storage tank or transported to shore via pipeline.

Case 3: Decentralised Offshore

In the decentralised offshore electrolysis scenario, also called in-turbine system, the electrolysers are integrated in or next to the tower of every turbine in the OWF. Individual desalination units are also installed in connection to each electrolyser as seawater is utilized. Hydrogen is produced from the electricity that is not used to power supporting components, such as the desalination and compressor units. The hydrogen produced is transported to a platform located within the wind farm area by small dimension pipelines, which hosts a compressor, an alkaline fuel cell and a storage tank. The hydrogen is compressed and either re-filling the storage tank or exported to shore via a larger dimension pipeline.

4.2 Production Calculations

In this part, the methodology of determining the wind power output, hydrogen production and electrical losses and consumption within the supporting system components is described. The following assumptions are valid throughout the calculations:

- The availability of the wind farm and electrolyser system is 97% and 95% respectively (Renewable Energy Association 2023; IEA 2019b).
- All wind turbines, within the park and between the cases, follow the same wind power curve, meaning that the cut-in and cut-out speed as well as the rated wind speed are the same for all turbines.
- Changes in air density, wind shear and turbulence are not considered.

The flowchart for the three electrolyser system configurations is shown in figure 8. E_{OWF} represents the total electricity generated by the wind farm, E_{ELEC} the electricity reaching the electrolyser, WT wind turbine, $E_{cons,DES}$ the electricity consumed by the desalination unit, $E_{cons,COMP}$ the electricity consumed by the compressor unit. $E_{loss,INT}$, $E_{loss,TRF}$ and $E_{loss,EXP}$ represent the electrical losses from the inter-array grid, transformer and export cable, respectively. $E_{loss,SYS}$ represents the system losses from the electrolyser system and the supporting components, occurring when electricity generated by the OWF is not sufficient for the system to be operating and thus lost.

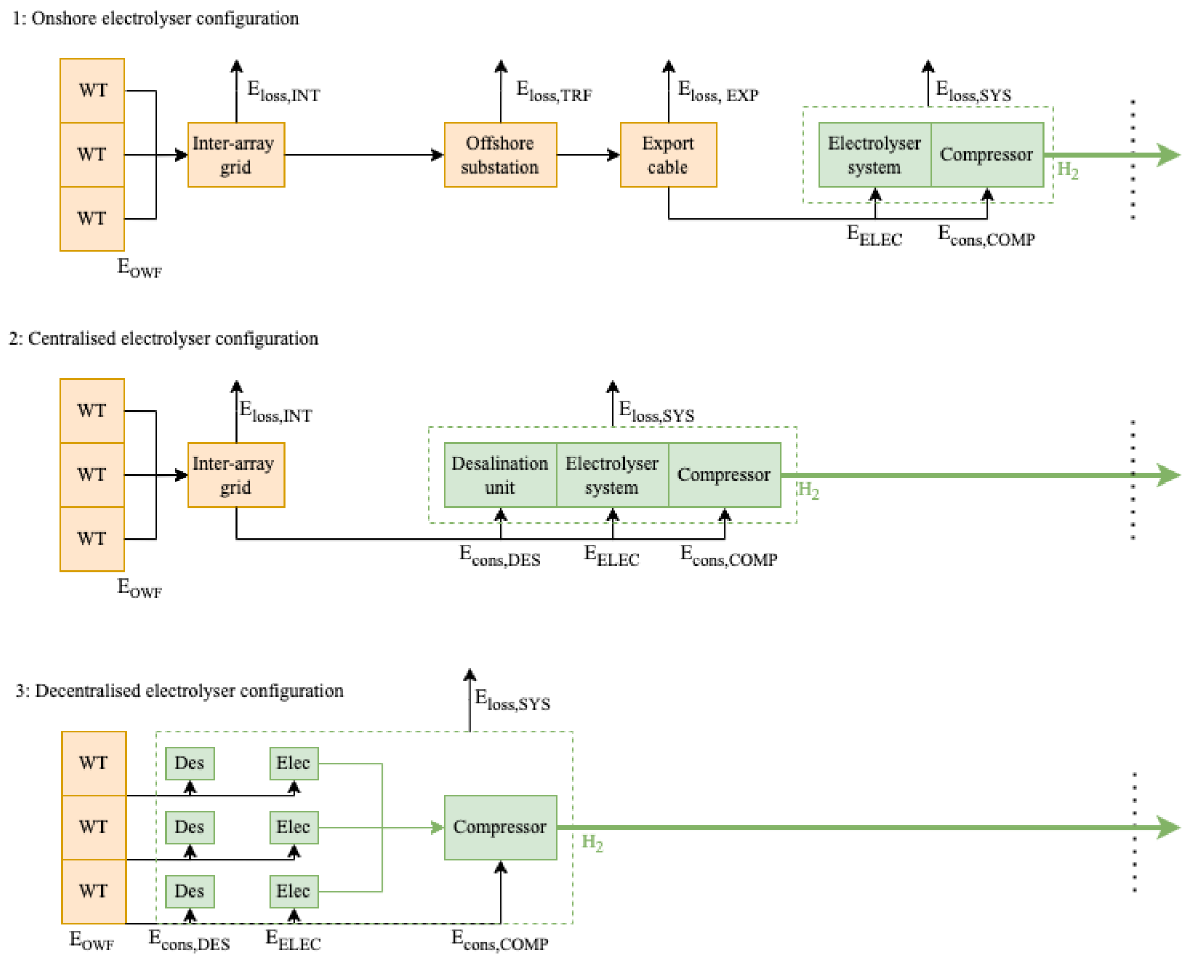
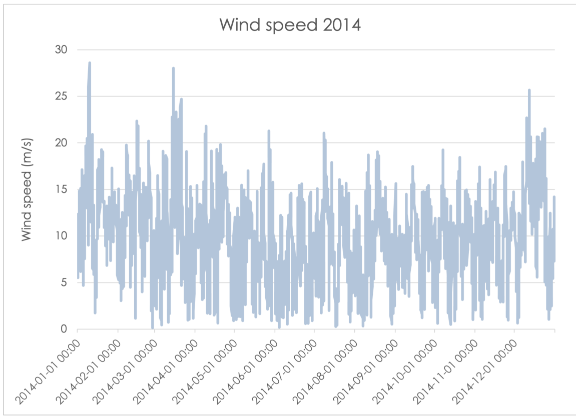


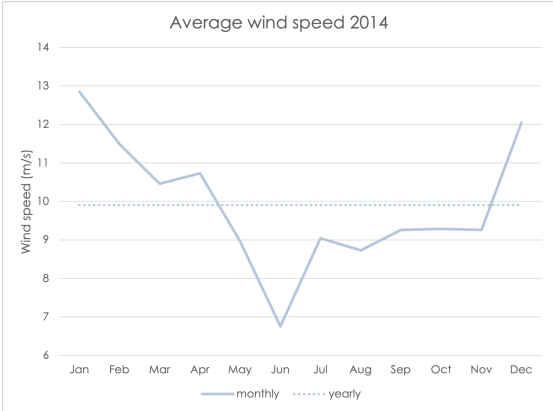
Figure 8: Flowchart of the three configurations

4.2.1 Wind Farm Power Output

A reference year has been chosen for the calculations which is assumed to be representative for all years of the system lifetime. In a statistically normal period, the wind speed index is 1. At the selected site, year 2014 had this desired index according to Global Wind Atlas and was therefore selected as the reference year. Wind data for 2014 is gathered from the intended position of the OWF, using the data set EMD-WRF Europe+. The hourly wind speed for the reference year is shown in figure 9a and the monthly average wind speed is shown in figure 9b.



(a) Hourly wind data



(b) Monthly and yearly average wind data

Figure 9: Hourly respective average monthly and yearly wind data at 150 m, within the project area in 2014. The figures are based on data from EMD-WRF Europe+.

The power, $P(t)$, generated from the wind turbines is dependent on the wind speed, v, as presented in equation 1. The power output is zero if the wind speed is below the cut-in wind speed, v_{ci} or above the cut-out wind speed, v_{co}. The power output follows a suggested power curve provided by Eolus, giving $P_f(v)$, for wind speeds between cut-in wind speed and rated wind speed, v_r. Between rated wind speed and cut-out wind speed the power output equals the rated power P_r. In this work it is assumed that $v_{ci} = 4$ m/s, $v_r = 13.5$ m/s, $v_{co} = 25$ m/s and $P_r = 20$ MW.

$$P(t) = \begin{cases} 0 & v < v_{ci} \\ P(v) & v_{ci} \leq v < v_r \\ P_r & v_r \leq v < v_{co} \\ 0 & v_{co} \leq v \qquad\qquad [kW] \end{cases} \tag{1}$$

Losses within the OWF is set to 15%, including turbine and supporting components unavailability, wake losses, blocking losses, degradation losses, sub-optimal performance and icing losses (discussed with Eolus). It is assumed that all turbines follow the same power curve and generates the same power output at time t. The power output from the OWF is the sum of the power output from all turbines, see equation 2. N is the number of wind turbines in the OWF, in this case set to 55.

$$P_{OWF}(t) = \sum_{i=1}^{N} P(t) \qquad [kW] \tag{2}$$

The electricity generated by the wind farm, E_{OWF} can further be described as in equation 3.

$$E_{OWF}(t) = P_{OWF}(t) \cdot \Delta t \qquad [kWh] \tag{3}$$

where the unit of Δt is set to hours in this work.

4.2.2 Electric Energy Supply

Additional losses arise in the transmission from the OWF to the electrolyser system. These losses will differ between the three studied configurations. E_{ELEC} represents the electric energy reaching and thus supplying the electrolyser and is calculated using equation 4.

$$E_{ELEC}(t) = E_{OWF}(t) - \sum E_{loss}(t) - \sum E_{cons}(t) \qquad [kWh] \tag{4}$$

where E_{loss} are losses after the OWF but prior to the electrolyser system which includes $E_{loss,INT}$, $E_{loss,TRF}$ and $E_{loss,EXP}$. In this work a loss coefficient of 0.3 % of the installed capacity (Das and Cutululis 2017) is used when calculating the losses from the transformer, $E_{loss,TRF}$. E_{cons} represents the electrical consumption of the supporting system components. The loss and consumption elements are all illustrated previously in the flowchart, figure 8.

4.2.3 Inter-array Grid

Each string of cables within the OWF consists of five turbines which are located with a distance of approximately 2 km between each other. The total length of the inter-array grid was determined to 114.5 km. The assumed use of cable for the grid are 66 kV HVAC cables with a loss coefficient of 0.55% (Singlitico et al. 2021) of the electrical energy produced. The inter-array grid is only relevant for the onshore and centralised configurations as the decentralised scenario is replaced with pipelines instead of cables. The inter-array cables are assumed to be buried in the seabed.

4.2.4 Export Cable

As previously mentioned, the break-even distance for when HVDC is more economically beneficial compared to HVAC is around 100 km (Groenemans et al. 2022). As the distance to shore from the OWF is about 25 km, the assumed cable used as the export cable is HVAC. This assumption also indicates that additional AC-DC converters outside the electrolyser system are not necessary in this configuration. With cables going from the two transformers to shore, the total length of the export cables was calculated to 67.4 km. The nominal voltage of the export cable is 400 kV and the cross-sectional area is 1000 mm^2 (Xiang et al. 2021). The electrical losses are assumed to be 6.7%/1000 km (EIA 2018). The export cable is only present in the onshore configuration to be able to transmit the produced electricity to the electrolyser onshore. The export cables are assumed to be buried in the seabed.

4.2.5 Desalination Unit

For the configurations centralised and decentralised offshore, the water source is sea water which requires desalination prior to the electrolysis. The dominating technology reverse osmosis is assumed to be used. It is also assumed that the size of the desalination plant is scaled so that the nominal volumetric flow rate equals the maximum value of volumetric flow rate required for the maximum hydrogen production rate, and is thus never a limiting factor for the hydrogen production. The electricity consumption of the desalination unit is calculated using equation 5.

$$E_{DES}(t) = \dot{m}_{H_2}(t) \cdot W_{DES} \cdot e_{DES} \cdot 10^{-3} \qquad [kWh] \tag{5}$$

where W_{DES} is the water consumption for each kilogram of produced hydrogen. Newborough and Cooley (2021) assumed the sea water consumption to be equal to 17 l/kg H_2. However, in this work, the value was set to 15 l/kg H_2, taking technological developments into account. e_{DES} is the electrical energy consumed in the desalination unit and is assumed to be 3.5 kWh/m^3 (IEA 2019a).

Desalination will not be necessary in the onshore configurations as fresh water will be purchased to provide the electrolyser. As the water consumption is 9 l/kg H_2 stoichiometrically, 10 l/kg H_2 is assumed to be the real consumption. The price of water was adapted from the municipality concerned.

4.2.6 Electrolyser System

The three electrolyser technologies, PEM, SOE and AEC, differ in their performance. The technical parameters used in this work are presented in table 3. The parameters are a forecast for 2030 where technology development is included. All the presented values are adapted from IEA (2019a).

Table 3: Technical parameters for PEM, SOE and AEC (IEA 2019a).

	PEM	SOE	AEC
Electrical efficiency, nominal (%, LHV)	65.5	80.5	68
Operating pressure (bar)	80	1	30
Operating temperature (°C)	80	1000	80
Stack lifetime (operating hours)	75 000	50 000	95 000
Degradation (%/1000 h)	0.1	0.5	0.1
Load range (% relative to nominal load)	0-160	20-100	10-110
Plant size (m^2/GW$_e$)	48 000	7000	95 000

The electrolyser will produce hydrogen if the supplied electricity is exceeding the minimum load, $\overline{P}_{ELEC} \cdot \Delta t \cdot \varphi_{MIN}$ where $\overline{P}_{ELEC}$ is the nominal capacity of the electrolyser. In this work all of the generated electricity from the OWF is dedicated to hydrogen production. $\overline{P}_{ELEC}$ is set to be equal to the maximum value of $E_{ELEC}/\Delta t$ for the reference year, meaning that all generated electricity is assumed to be consumed. The energy of the hydrogen produced, E$_{H_2}$, is calculated using equation 6.

$$E_{H_2}(t) = \begin{cases} E_{ELEC}(t) \cdot \eta_{ELEC}(t) & \text{if } \overline{P}_{ELEC} \cdot \Delta t \cdot \varphi_{MIN} \leq E_{ELEC}(t) \\ 0 & \text{if } E_{ELEC}(t) < \overline{P}_{ELEC} \cdot \Delta t \cdot \varphi_{MIN} \qquad [kWh] \end{cases} \tag{6}$$

where $\eta_{ELEC}(t)$ represents the system electrical efficiency. Due to degradation, $\eta_{ELEC}(t)$ will decrease over time. For this work it is assumed that the efficiency for each electrolyser is decreasing linearly over time, using equation 7.

$$\eta_{ELEC}(t) = \overline{\eta}_{ELEC} \cdot (1 - \frac{\eta_{DEG}}{1000} \cdot \frac{OH}{LH} \cdot t) \tag{7}$$

The lifetime of the electrolyser system is assumed to be the same as the wind farm, 35 years. The lifetime hours are thus 35·8760 hours, denoted as LH in the equation. OH are the total operational hours over the lifetime and are a sum of the hours where $E_{ELEC}(t) < \overline{P}_{ELEC} \cdot \Delta t \cdot \varphi_{MIN}$. However, the lifetime of the electrolyser stack is less than the assumed system lifetime. The lifetime equals the operating hours, OH_{MAX}, of each electrolyser, and is found in table 3. The stacks are replaced when their lifetime has expired, according to equation 8. When replaced, the nominal efficiency, $\overline{\eta}_{ELEC}$, is restored.

$$t_{ON} = n \cdot OH_{MAX} + 1 \tag{8}$$

where t_{ON} represents the number of hours of which the electrolyser has been turned on.

The mass flow rate of hydrogen is determined using equation 9.

$$\dot{m}_{H_2}(t) = \frac{E_{H_2}(t)}{LHV_{H_2}} \qquad [kg/h] \tag{9}$$

where LHV_{H_2} is the lower heating value of hydrogen which is equal to 33.3 kWh/kg.

4.2.7 Compression Unit

A compression unit is present in all of the three system configurations. The desired pressure in the hydrogen pipeline at shore is 70 bar. Due to pressure drop, the inlet pressure in the pipeline is 98 bar (North Sea Energy 2020). Therefore, the compression unit at sea will raise the pressure from the operating pressure of the electrolysers to 98 bar, whereas the compression unit onshore will compress from the electrolysers' operating pressure to 70 bar. The assumed compression process for this work is an adiabatic compression. The selected compressor is a centrifugal seeing that it is better suited for high volume flows and requires relatively low pressure.

The consumed electricity for hydrogen compression varies between both the configurations and the technologies. The difference between the configurations occurs as they need different outlet pressures of the compressor, 98 bar for the offshore configurations and 70 bar for the onshore. The difference between the technologies is due to their different operating pressures, i.e. different inlet pressures of the compressor. For the onshore configuration, 4 and 10 MJ/kg is required when producing with an AEC and a SOE, respectively. Furthermore, 1, 5 and 11 MJ/kg is consumed when producing offshore with PEM, AEC and SOE, respectively (Bossel and Eliasson n.d). The assumed efficiency, the ratio of the work required to adiabatically compress the hydrogen to the work actually done, of the centrifugal compressor is 80% (Atlas Copco n.d).

4.2.8 Hydrogen Pipelines

In the decentralised offshore scenario, internal pipelines are assumed to equal the length of the onshore scenario's inter-array cables, consisting of 114.5 km, leading to the offshore platform with a compressor unit. For both the decentralised and centralised offshore scenarios, an export pipeline is in place between the offshore platform and shore, 35 km long. Calculations in this work show a maximum mass flow rate of hydrogen of 20 300 kg/h. With the assumption that the flow is equally distributed between the 11 strings of pipelines in the decentralised configuration, the maximum mass flow rate is 1 850 kg/h. The diameter for the export pipeline is assumed to be 24.5 cm (North Sea Energy 2020) and the internal pipelines are assumed to be 15 cm (Wlodek et al. 2019). Pressure drop in the export pipeline are accounted for, with an inlet pressure of 98 bar and an outlet pressure of 68 bar (North Sea Energy 2020).

4.2.9 Offshore Platform

The aim of the offshore platform is to host different components of the wind farm and the electrolyser systems. For the onshore configuration, the platform holds the transformer, whereas for the centralised configuration, the platform hosts the electrolyser system, desalination unit, compressor and backup power source. In the decentralised configuration, the compressor and the backup power source are placed on the platform.

As presented in table 3, the plant size of the electrolysers are 48 000 m^2/GW for PEM, 95 000 m^2/GW for AEC and 7000 m^2/GW for SOE (Singlitico et al. 2021). Although the size varies, the price of the platform is adapted from an offshore substation in a wind farm, with the assumption that the platform has a sufficient size to host all the electrolyser systems. This assumption was done due to lacking information of costs.

4.2.10 Backup Power Source

When the wind speed is outside the range of cut-in and cut-out speed or when maintenance is carried out, the wind turbines will not produce electricity, however some electricity will be required to supply different components of the turbine. Furthermore, when electricity is not sufficiently supplied in relation to the minimum load of the electrolyser, a backup power source is necessary. This will make the electrolyser operate in a hot standby state which requires electricity although hydrogen is not produced. The hot standby state maintains the temperature and pressure close to the operating parameters. Cold starts are therefore avoided and degradation is prevented. For all electrolyser technologies, 5% of the nominal load is needed for hot standby (Matute et al. 2021; Rowenhorst 2023).

For this work, an alkaline fuel cell was chosen as the backup power source due to its characteristics and advantages. The fuel cell typically has an efficiency, η_{FC}, of 65 % (GenCell n.d) and does not require pre-heating, even at low temperatures. Moreover, the alkaline fuel cell is resistance to salt air and humidity making it suitable for an offshore placement.

It is assumed that each turbine consumes 500 kW when not producing electricity (discussed with Eolus). The electricity consumed over the plant's reference year, $E_{cons,OWF,Y}$ is thus calculated using equation 10.

$$E_{cons,OWF,Y} = \sum_{t=0}^{8760} B(t)_{OWF,off} \cdot P_{cons,OWF} \qquad [kWh] \tag{10}$$

where $B(t)_{OWF,off}$ is a Boolean parameter which is 1 if the OWF is not generating electricity and 0 if it is, and $P_{cons,OWF}$ is the power consumption for the entire OWF.

The electrolyser system is in hot standby mode and thus consuming electricity when $E_{ELEC}(t) < \overline{P}_{ELEC} \cdot \Delta t \cdot \varphi_{MIN}$. The yearly consumption is calculated using equation 11.

$$E_{cons,ELEC,Y} = \sum_{t=0}^{8760} B(t)_{ELEC,off} \cdot 0.05\overline{P}_{ELEC} \qquad [kWh] \tag{11}$$

where $B(t)_{ELEC,off}$ is a Boolean parameter which is 1 if the ELEC is in hot standby state and 0 if it is producing hydrogen. The hydrogen mass that is required to cover the yearly electricity need, m_{cons,H_2}, is calculated using equation 12. It is assumed that degradation of the fuel cell is negligible and thus not accounted for.

$$m_{cons,H_2,Y} = \frac{E_{cons,OWF,Y} + E_{cons,ELEC,Y}}{\eta_{FC} \cdot LHV_{H_2}} \qquad [kg/year] \tag{12}$$

4.2.11 Storage Tank

To supply the fuel cell with hydrogen when necessary, a storage tank will be installed. For the reference year, the fuel cell will be operating at a maximum of 29 hours consecutively. The capacity of the storage tank is set to equal 48 hours of the fuel cell operating at nominal capacity, covering the electricity need. The amount of hydrogen needed in the tank to cover 48 hours is calculated using equation 13.

$$m_{cons,H_2} = \frac{48 \cdot (P_{cons,OWF} + P_{cons,ELEC})}{\eta_{FC} \cdot LHV_{H_2}} \qquad [kg] \tag{13}$$

4.3 Techno-economic Analysis

An extensive literature study was carried out where cost data was collected from an amount of different academic sources. The relevant costs are presented in table 4 and table 5 where a conversion from their original currency to SEK was made, using the exchange rates that have been used throughout this work. The cost denoted as other in table 4 includes, for instance, operations base, profit, warranty, insurance and construction project management. Regarding the compression unit in table 5, SF is the scale factor which is assumed to be 0.8335 for this work. The asterisk in both of the tables indicates that the cost is a forecast for 2030.

Table 4: Expenditures for the wind farm.

Expenditures				Configurations	References
Wind turbine		10.00	MSEK/MW	All	(BVG Associates 2019)
Foundation		65.75*	MSEK/turbine	All	(Bulder et al. 2021)
Inter-array cables		2.49	MSEK/km	1,2	(Ruigrok et al. 2019)
Export cables		19.87	MSEK/km	1	(Xiang et al. 2021)
Substation		1.54	MSEK/MW	1	(BVG Associates 2019)
	Of which platform	0.77	MSEK/MW	All	(BVG Associates 2019)
Installation		5.19	MSEK/MW	All	(BVG Associates 2019)
Other		7.16	MSEK/MW	All	(BVG Associates 2019)
OPEX		3% of CAPEX	MSEK/MW	All	(BVG Associates 2019)

Table 5: Expenditures for the electrolyser system, including back-up power source and storage tank.

Expenditures			Configurations	References
PEM	11.17*	MSEK/MW	All	(IEA 2019a)
AEC	6.49*	MSEK/MW	All	(IEA 2019a)
SOE	18.70*	MSEK/MW	All	(IEA 2019a)
Stack replacement	30% of electrolyser cost	MSEK/MW	All	(Danish Energy Agency 2020)
Desalination unit	16.42*	kSEK/(m^3/day)	2,3	(Caldera and Breyer 2017)
Fresh water	50	SEK/m^3	1	(Ruderstam 2022)
Pipelines (installation + equipment)	0.32	MSEK/cm/km	2,3	(Armiño Franco et al. 2021)
Compression unit	47.73	kSEK/kW^{SF}	All	(Khan et al. 2021)
Alkaline fuel cell	1.54	MSEK/MW	All	(Ferriday and Middleton 2021)
Storage tank	7.27	kSEK/kg H_2	All	(Rajeevkumar Urs et al. 2023)
Installation	0.64	MSEK/MW	All	(BVG Associates 2019)
OPEX	2% of CAPEX	MSEK/MW	All	(Danish Energy Agency 2020)

In this case study, the construction of the wind power-electrolyser system is assumed to take place in 2030, thus costs at that time are of interest. The inflation rate is considered for the prices which are not already a forecast for 2030 and calculated using equation 14.

$$FV = \frac{PV}{(1+i)^{-N}} \tag{14}$$

where FV equals future value, PV equals present value, i equals the annual inflation rate and N number of years. In this work i is set to 2.5% and n is 7 years, seeing that 2030 occurs in 7 years from now. More detailed information about the costs with the inflation rate included can be found in the appendix.

4.3.1 Levelised Cost of Electricity

Levelised cost of electricity (LCOE) is a measurement of the average cost for producing electricity over the generator's lifetime. In this work, the LCOE applies for the amount of electricity produced by the OWF which reaches the electrolyser system. It is calculated by adding all costs of production related to the OWF and dividing by its estimated lifetime electricity production, see 15.

$$\sum_{Y=0}^{LT_Y} \frac{CAPEX_{OWF,Y} + OPEX_{OWF,Y}}{(1+DR)^Y} / \sum_{Y=0}^{LT_Y} \frac{E_{OWF,Y} - E_{loss,Y}}{(1+DR)^Y} \qquad [SEK/kWh] \quad (15)$$

where $CAPEX_{OWF,Y}$ and $OPEX_{OWF,Y}$ represents the capital and operational expenditures over the year Y, $E_{OWF,Y}$ represent the total electrical energy generated by the wind farm the year Y and $E_{loss,Y}$ is the losses between the OWF and the electrolyser and its auxiliary equipment. DR represents the discount rate and is assumed to be 8%. The LCOE will likely differ between the different system configurations and electrolyser technologies due to differences in electrical losses.

4.3.2 Levelised Cost of Hydrogen

Levelised cost of hydrogen (LCOH) is similarly a measurement of the average cost for producing hydrogen over the system's lifetime, as presented in equation 16. As all electricity consumed by the electrolyser and the supporting system components, $E_{SYS,Y}$, is supplied from the OWF, the LCOE calculated represents the price of the electricity. $CAPEX_{SYS,Y}$ and $OPEX_{SYS,Y}$ represents the capital and operational expenditures, respectively, related to the electrolyser system. These expenditures do not include expenditures related to the OWF, such as the turbines or the electrical cables as these are already accounted for in the LCOE. $V_{FW,Y}$ represents the volume of fresh water used for year Y, and p_{FW} the price of the water. $V_{FW,Y}$ is zero for the offshore scenarios where the sea is the water source. $m_{H_2,Y}$ is the mass produced hydrogen for year Y. However, as a share of the hydrogen is used to supply the fuel cell and not leaving the system, $m_{cons,H_2,Y}$ is deducted.

$$\begin{aligned}&\sum_{Y=0}^{LT_Y} \frac{LCOE \cdot E_{SYS,Y} + CAPEX_{SYS,Y} + OPEX_{SYS,Y} + V_{FW,Y} \cdot p_{FW}}{(1+DR)^Y} \\ &/ \sum_{Y=0}^{LT_Y} \frac{m_{H_2,Y} - m_{cons,H_2,Y}}{(1+DR)^Y} \qquad [SEK/kgH_2]\end{aligned} \quad (16)$$

5 Results

In the following section, results from the techno-economic analysis will be presented. This includes a determination of electricity consumption for several components, the produced and consumed hydrogen as well as the calculated values for LCOE and LCOH for the different electrolysers and system configurations.

5.1 Production and Consumption

The consumed electricity for desalination and compression are presented in table 6 and 7. If values are absent in the tables, the component is not present in that specific configuration. When the electrolyser is placed onshore, fresh water is used and consequently, a desalination unit will not be necessary. The assumed operating pressure for PEM is 80 bar and the desired outlet pressure onshore is 70 bar, thus compression is not accounted for in the onshore configuration.

Table 6: Electricity consumption for the desalination unit.

Electricity consumption, desalination unit (GWh/year)	PEM	SOE	AEC
Onshore	-	-	-
Centralised	4.70	5.06	4.79
Decentralised	4.72	5.09	4.81

Table 7: Electricity consumption for the compression unit.

Electricity consumption, compression unit (GWh/year)	PEM	SOE	AEC
Onshore	-	332.39	125.66
Centralised	31.08	368.41	158.27
Decentralised	31.25	370.45	159.14

From table 6 and 7, it can be seen that SOE system has the highest electricity consumption for desalination as well as for compression, whereas PEM has the lowest. Due to the high operating pressure in a PEM, the outlet pressure is high, and thus the electricity needed for compression is considerably lower compared to the other technologies.

During a year, PEM is calculated to not sufficiently be supplied with electricity, i.e. the supply is below the minimum load, leading to a stand-by mode in 10.71% of the year. For SOE and AEC the time in stand-by mode is 26.63% and 19.10% of the year, respectively. The hydrogen consumed in table 8 corresponds to the amount of electricity needed to supply the electrolysers in order to remain in stand-by mode as well as to supply the OWF when turned off.

Table 8: Yearly consumption of hydrogen.

Hydrogen consumed (Mkg/year)	PEM	SOE	AEC
Onshore	2.00	4.62	3.47
Centralised	2.00	4.61	3.47
Decentralised	2.01	4.64	3.49

The hydrogen that will be consumed is stored in a tank until needed in the system. The storage tank is calculated to require a volume of 20 937 m^3 for the onshore configuration, 19 356 m^3 for the centralised and 20 959 m^3 for the decentralised scenario. These calculations are based on the PEM electrolyser since that is the technology that requires most power when turned off.

The yearly produced electricity from the OWF was calculated to 4.83 TWh. With a 95% availability for the electrolysers, the useful hydrogen after desalination, compression and internal usage is displayed in table 9.

Table 9: Yearly production of useful hydrogen.

Hydrogen produced (Mkg/year)	PEM	SOE	AEC
Onshore	82.38	79.81	80.20
Centralised	82.39	79.70	80.17
Decentralised	82.85	80.14	80.61

5.2 Levelised Cost of Electricity

The results of the LCOE for each configuration and electrolyser technology for a lifetime of 35 years and a discount rate of 8% is presented in figure 10. The results represent the levelised cost of the electricity which reaches the electrolyser system, i.e. the electricity produced from the OWF with electrical losses prior to the electrolyser system deducted.

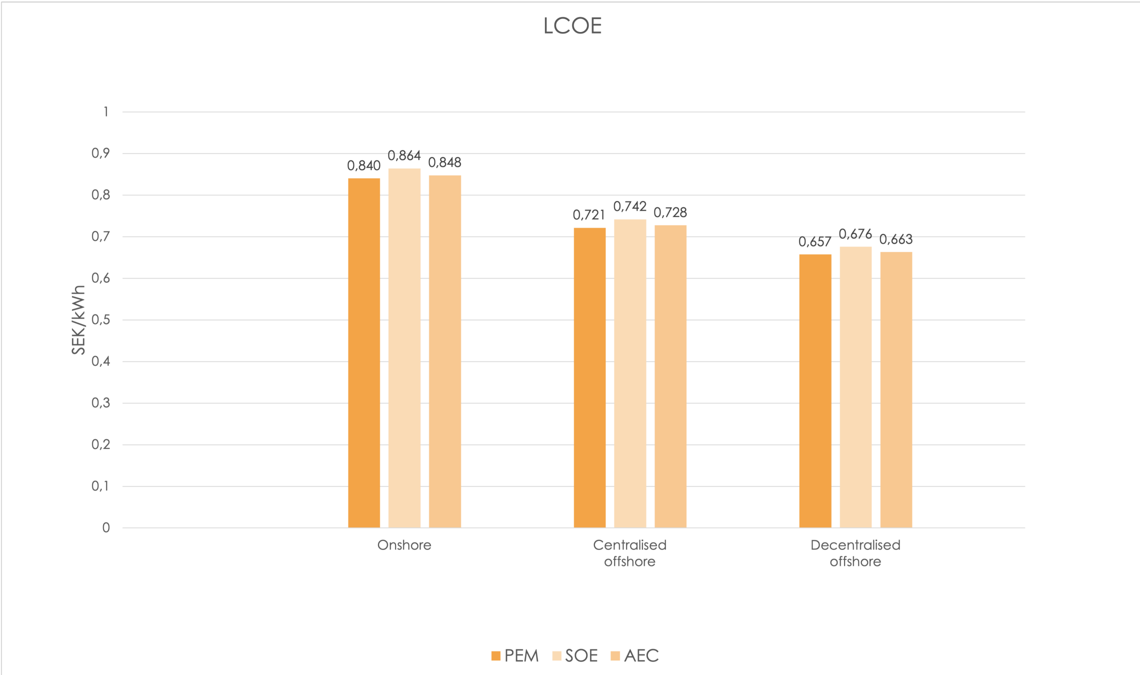


Figure 10: LCOE for the different system configurations and electrolyser technologies.

The LCOE is the lowest in the decentralised configuration and highest in the onshore configuration. Using the PEM electrolyser, LCOE is found to be the lowest and with the SOE it is found to be the highest. The lowest LCOE, 0.657 SEK/kWh, is given by the decentralised offshore configuration with PEM electrolyser. The highest value of LCOE is 0.864 SEK/kWh, found in the onshore configuration with the SOE technology. Note that the onshore configuration includes infrastructure that would enable electricity to reach shore and connect to the grid. The LCOE for this configuration would thus correspond to the average cost for electricity delivered to the grid, for this hypothetical wind farm.

5.3 Levelised Cost of Hydrogen

The calculated LCOH considering a lifetime of 35 years and a discount rate of 8% is presented in figure 11.

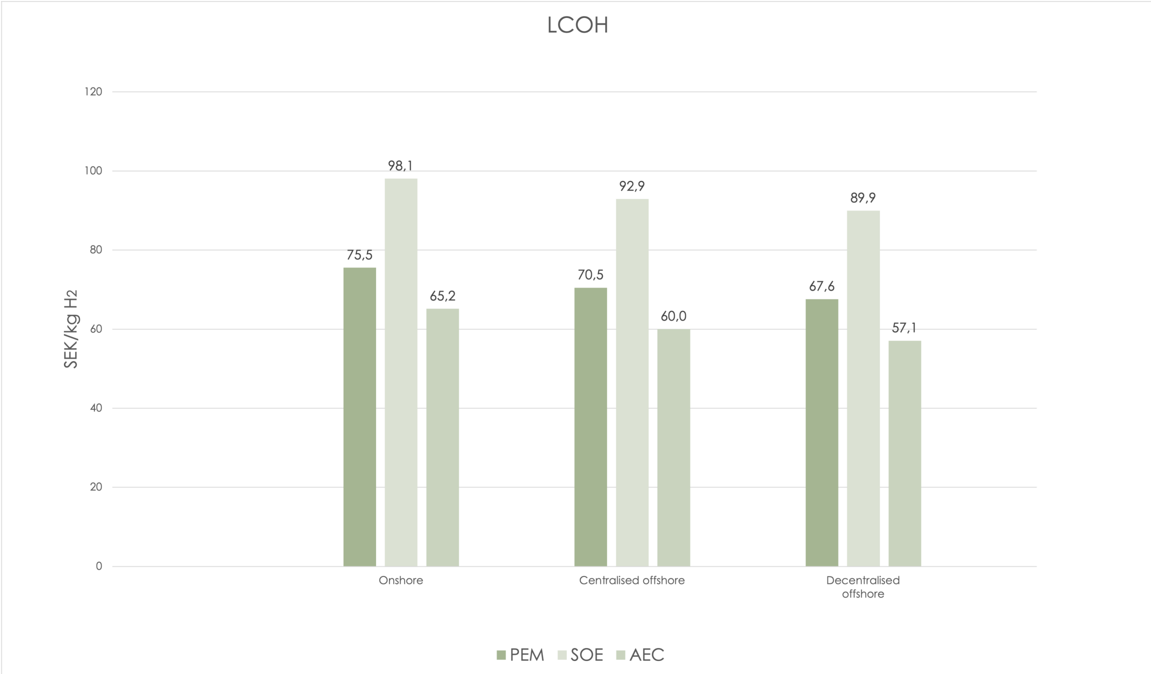


Figure 11: LCOH for the different system configurations and electrolyser technologies.

Comparing the configurations, decentralised offshore is the cheapest and onshore is the most expensive. Comparing the electrolyser technologies, AEC is the cheapest and SOE the most expensive. The costs are ranging between 57.1 and 98.1 SEK/kg H_2.

6 Analysis

In this chapter the results are further analysed. The parameters primarily affecting the results are identified by breakdowns of the results. An assessment of the credibility of the results is conducted by comparing the results with previous research and existing predictions. To determine uncertain input values impact on the overall uncertainty of the study, a sensitivity analysis is included. The section also includes a discussion, where the study in the overall perspective is examined. Finally, the limitations of the work are presented.

6.1 Analysis of the Results

Levelised Cost of Electricity

The higher LCOE in the onshore configuration (10) can be derived to the additional cost of cables and electrical losses in the cables and transformers. The LCOE is the lowest in the decentralised offshore configuration where no cables are required, reducing the CAPEX and electrical losses. The difference between the electrolyser technologies is related to their respective minimum load. With a higher minimum load, more electrical energy is lost.

To identify factors with great impact on the results, a cost breakdown of the OWF is conducted. The onshore system configuration is selected to show the impact of both the inter-array and export cables. The results are showed in figure 12 where all the categories include both equipment and installation, except for *OPEX* and *Other*. The cost denoted as other includes, for instance, operations base, profit, warranty, insurance and construction project management.

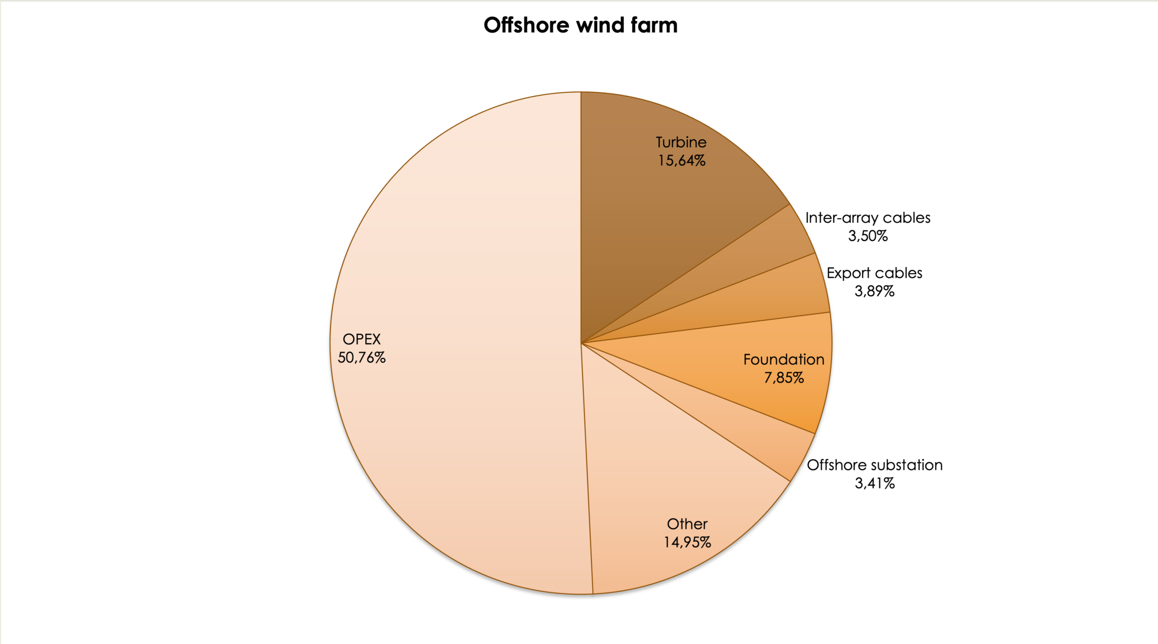


Figure 12: Cost breakdown of the OWF over its lifetime, onshore configuration.

In the cost breakdown of the OWF (figure 12) OPEX, which is 3% of CAPEX, per year, constitutes the largest part of the total as the cost is recurrent throughout the lifetime of the system.

Levelised Cost of Hydrogen

A main component when calculating the LCOH is the sum of the costs over the electrolyser system's lifetime. A comparison between the lifetime costs is thus of interest and presented in figure 13.

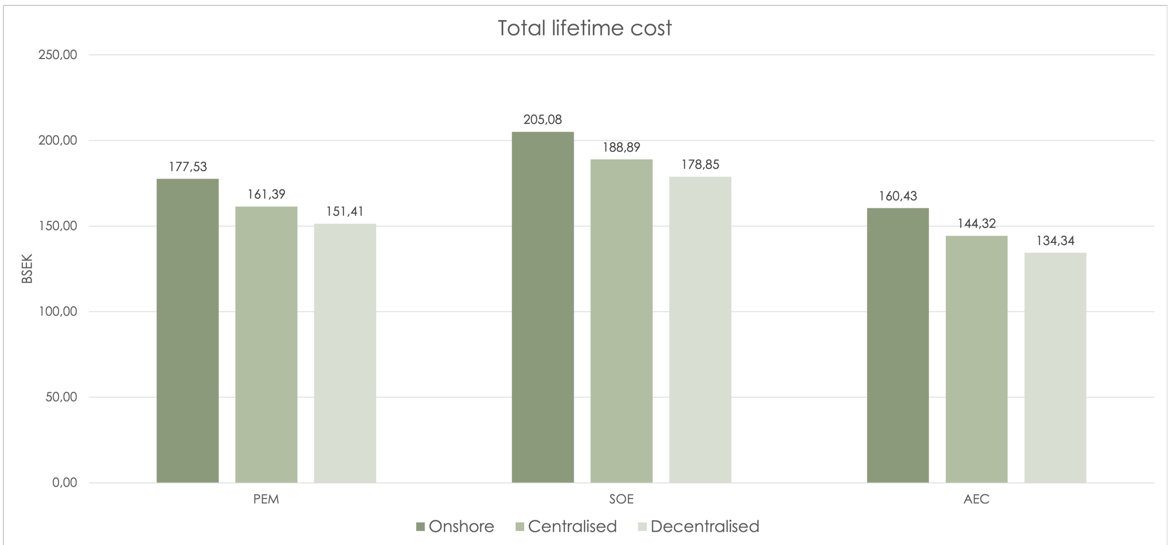


Figure 13: The sum of costs over the lifetime in billion SEK for the different system configurations and electrolyser technologies, discount rate not considered.

The SOE technology has the highest total lifetime cost and is producing the least amount of hydrogen. In addition it consumes the most hydrogen as it has the highest minimum load, leading to the highest amount of standby hours. These factors are reflected in the LCOH results, where the SOE has a significantly higher cost (figure 11). Although PEM is producing more and consuming less hydrogen than AEC (table 8, 9), its resulting LCOH is higher. This can be derived to the lower total lifetime cost of AEC.

Variations in total lifetime cost is found between the system configurations, where the onshore configuration consistently has the highest cost and the decentralised the lowest. This is coherent with the LCOH results, although the difference between the configurations is found smaller than between the electrolyser technologies. The hydrogen production, also impacting the LCOH, is the highest in the decentralised configuration and the lowest in the onshore or centralised configuration depending on the choice of electrolyser (table 9).

A cost breakdown is performed for each electrolyser technology as well, illustrated in figures 14, 15 and 16. The analysis is performed in the centralised offshore configuration, where both desalination units and pipelines are included. Seeing that the ratio between the technologies is similar in all three configurations (figure 11) and the supporting components in the system only represents a relatively small share, it is assumed that the breakdown is approximately representative for all configurations.

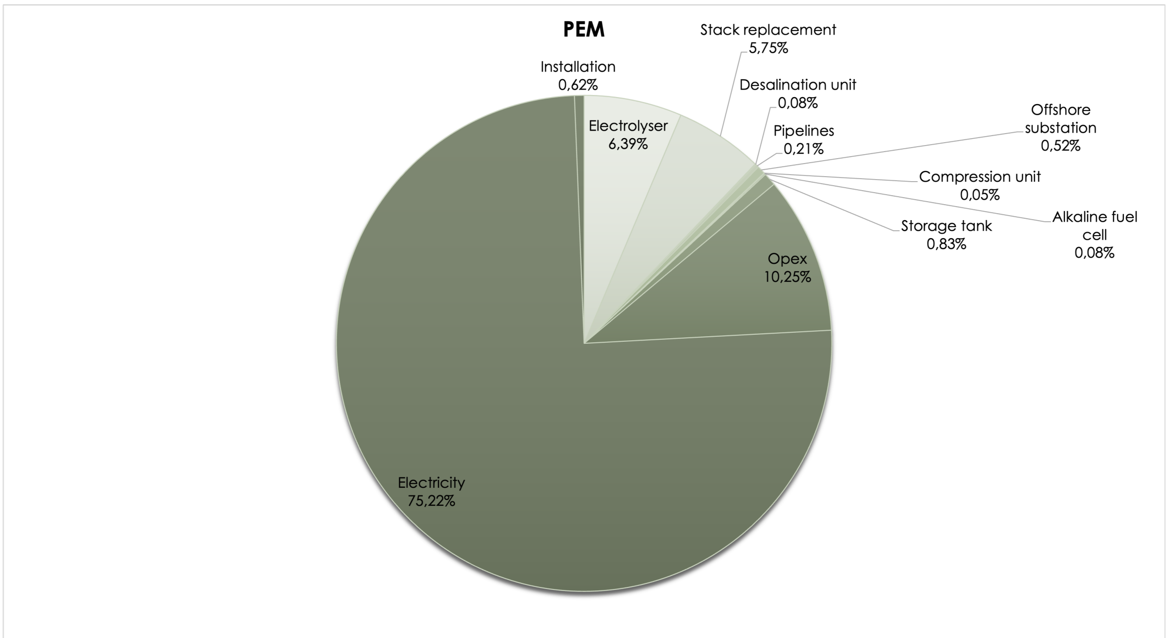


Figure 14: Lifetime cost breakdown of a PEM over its lifetime, centralised configuration.

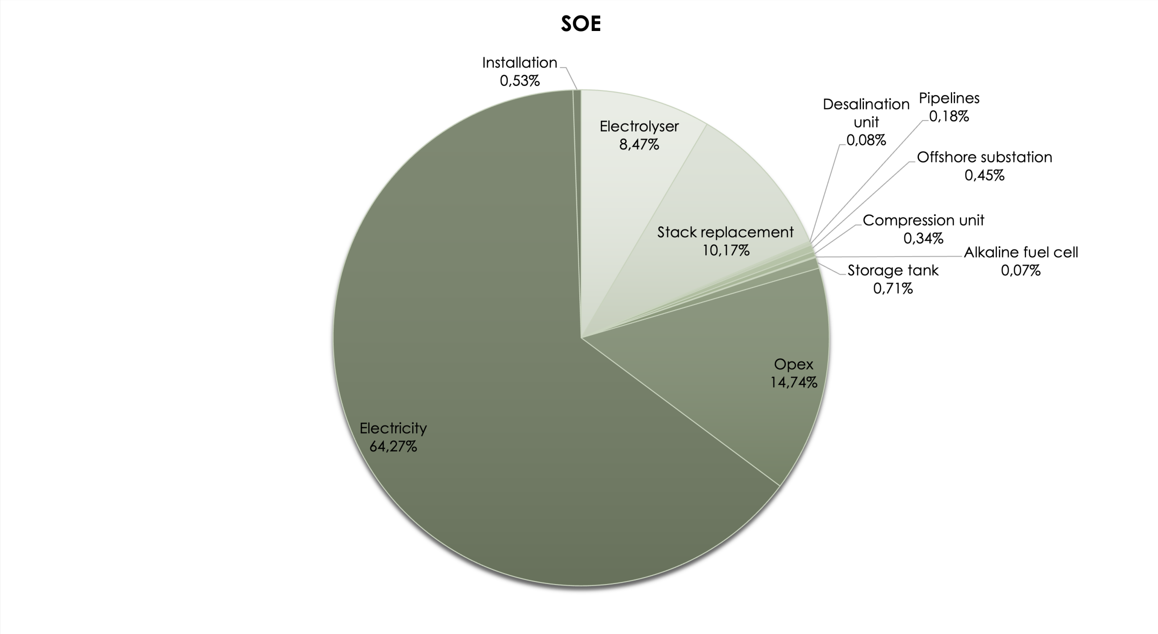


Figure 15: Lifetime cost breakdown of a SOE over its lifetime, centralised configuration.

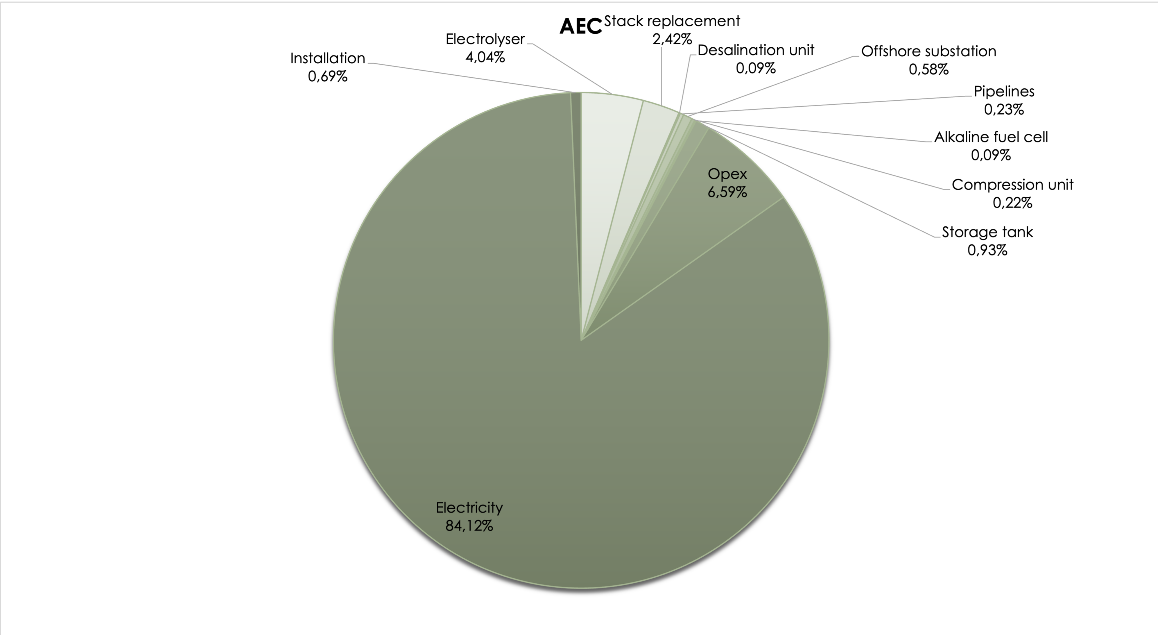


Figure 16: Lifetime cost breakdown of a AEC over its lifetime, centralised configuration.

As illustrated in figures 14, 15 and 16, the cost of electricity is the biggest cost over all electrolysers' lifetime. The electricity cost is dependent on the electricity consumed and the production cost of electricity in the wind farm, i.e. the LCOE. The CAPEX of the electrolyser differs between the technologies. SOE has the highest capital cost and AEC the lowest. The cost of stack replacement also varies between the electrolysers, mainly as a consequence of different stack lifetimes. Over a lifetime of 35 years, the stacks are replaced 2 times in the AEC, 3 times in the PEM and 4 times for SOE.

6.2 Comparison with Previous Research

To assess if the results are reasonable, a comparison with other predictions and analyses of LCOE and LCOH will be presented in this section.

The LCOE calculated in this study is ranging between approximately 0.66-0.86 SEK/kWh. However, when comparing to other LCOE, it is primarily the LCOE in the onshore case that is of interest, as this would correspond to the electricity that could be delivered to the grid. The onshore LCOE is approximately 0.84-0.86 SEK/kWh. IRENA predicted in 2019, that by 2030 the global average LCOE will range between 0.52 and 0.94 SEK/kWh (IRENA 2019). The calculated LCOE in this work is found within this range. However in 2021, the weighted average LCOE in Europe already reached this range, 0.68 SEK/kWh (IRENA 2022b). Seeing this development, it is plausible that the future LCOE in Europe is towards the lower value of the predicted range. If so, the calculated LCOE in this work is relatively high.

The LCOH calculated is ranging between 57.1-98.1 SEK/kg H_2. For comparison, IRENA (2022a) predicts LCOH from wind power in Germany by 2030 to approximately 14.5 SEK/kg H_2, Deloitte (2022) forecasts LCOH from offshore wind with off-grid electrolysis to 41.5 SEK/kg H_2 and IEA (2019a) predicts LCOH from renewable sources to about 31.2 SEK/kg H_2. The LCOH from this work is thus relatively high compared with the other predictions. The cost breakdowns of LCOH (figures 14 15 and 16) show that the electricity by far is the largest cost item. If the LCOE in this work is overestimated, as the European weighted average indicate, the LCOH might be overestimated as well. A possible reason for the high LCOE might be that the costs for the wind farm used in this work is too high to apply for 2030. When comparing to other results, it should be emphasized that the model of this work is a simplification that only considers the major system components and where the input values should be considered as estimations. Present costs have been used and adjusted with inflation when predicted costs could not be found, without considering any learning or scale factors.

For further comparison, the previous research previously presented in table 2 has calculated LCOH to range from as low as 17.0 to as high as 151.5 SEK/kg H_2. The results of 57.1-98.1 SEK/kg H_2 are within this range. However, the wide range of LCOH calculated indicates that a direct comparison is difficult to execute without also comparing model, input values and assumptions.

6.3 Sensitivity Analysis

As the case study considers a future scenario, there is a high uncertainty of used input values as future costs and technical parameters will be strongly related to the technological and economical development of hydrogen. A sensitivity analysis will be presented in this section, acting as an in-depth study of uncertain parameters and their contribution to the study's overall uncertainty.

6.3.1 Nominal Capacity of Electrolysers

So far in this work, the nominal capacity of the electrolyser, $\overline{P}_{ELEC}$, has been scaled to the maximum electricity reaching the electrolyser for each configuration, i.e. the maximum value of $E_{ELEC}/\Delta t$. $\overline{P}_{ELEC}$ for each configuration and the capacity in relation to the OWF (1100 MW) is presented in table 10.

Table 10: Nominal capacity of electrolysers in the base scenario.

Nominal capacity, $\overline{P}_{ELEC}$	PEM		SOE		AEC	
	MW	%	MW	%	MW	%
Onshore	922.8	83.9	856.7	77.9	898.3	81.7
Centralised	922.9	83.9	855.6	77.8	898.1	81.6
Decentralised	928.0	84.4	860.3	78.2	903.0	82.1

If the nominal capacity of the electrolysers, $\overline{P}_{ELEC}$, is lower than the maximum value of $E_{ELEC}/\Delta t$, the production will have a upper limit, as presented in equation 17.

$$E_{H_2}(t) = \begin{cases} \overline{P}_{ELEC} \cdot \Delta t & \text{if } E_{ELEC}(t) \geq \overline{P}_{ELEC} \cdot \Delta t \\ E_{ELEC}(t) \cdot \eta_{ELEC}(t) & \text{if } \overline{P}_{ELEC} \cdot \Delta t \cdot \varphi_{MIN} \leq E_{ELEC}(t) < \overline{P}_{ELEC} \cdot \Delta t \\ 0 & \text{if } E_{ELEC}(t) < \overline{P}_{ELEC} \cdot \Delta t \cdot \varphi_{MIN} \qquad [kWh] \end{cases} \tag{17}$$

A sensitivity analysis is conducted to identify if it is profitable to reduce the nominal capacity of the electrolysers. The results are presented in figure 17 and 18, where the nominal capacity is 10 and 20% lower than when scaled after the maximum value of electricity.

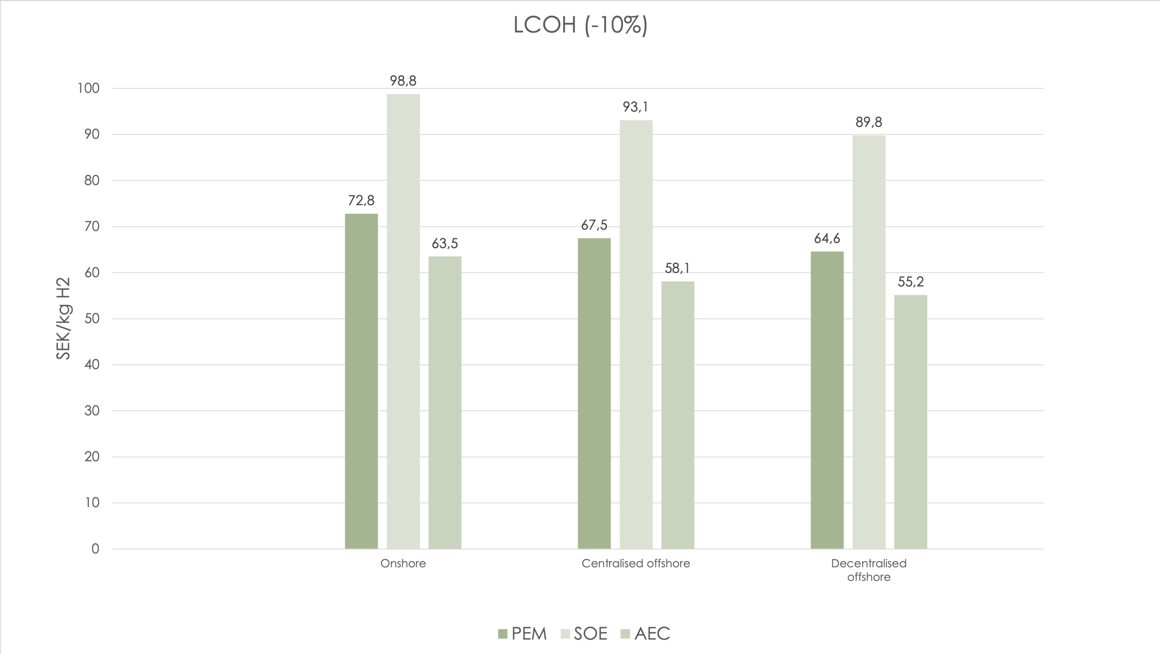


Figure 17: LCOH for nominal capacity minus 10% of maximum

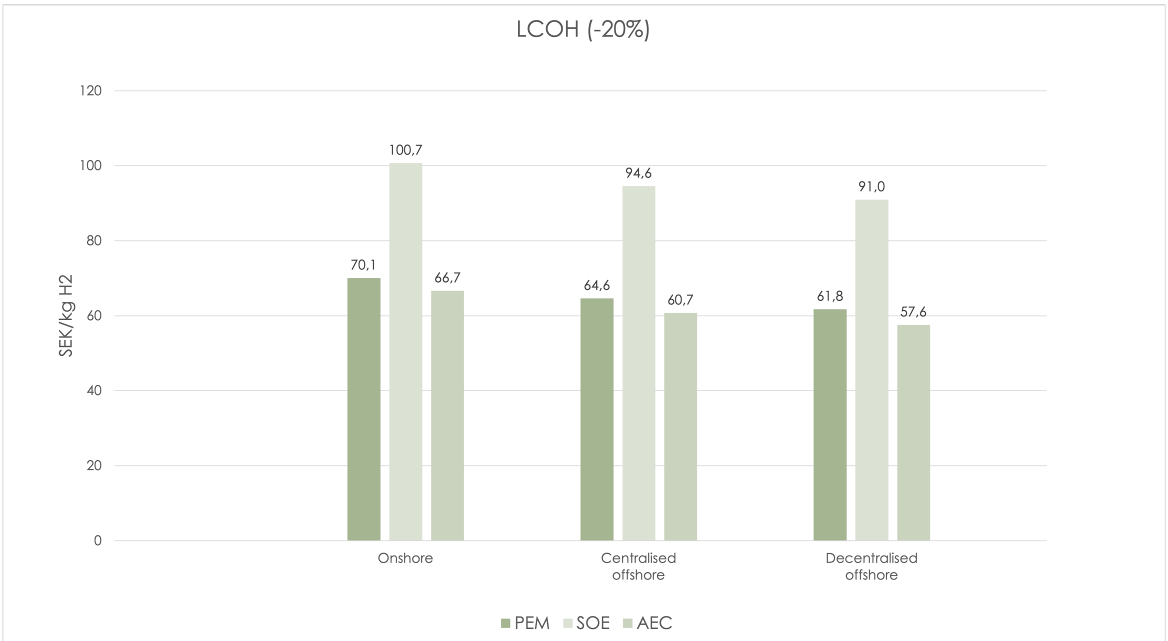


Figure 18: LCOH for nominal capacity minus 20% of maximum

When changing the nominal capacity of the electrolysers, the LCOH is affected. In the scenario where the nominal capacity is reduced by 10%, the LCOH for PEM and AEC decrease, comparing with the base scenarion in figure 11. In contrast the LCOH increases for SOE. When the nominal capacity is reduced by 20%, the LCOH for AEC is again increasing, above the LCOH for the base scenario. This indicates that it is only profitable to reduce the nominal capacity, and therefore the size, of AEC up to 10%. PEM will still have a lower LCOH until the nominal capacity is reduced by 38%, meaning that there is a great ability to reduce the size of PEM and thereby making it more profitable.

It is worth mentioning that the main reason why it proved to be profitable to decrease the size of the PEM and AEC is that they have the ability to produce hydrogen at loads higher than their nominal capacity. PEM electrolyser has a maximum load of 160% and AEC has a maximum load of 110%. Calculations show that PEM and AEC produces over the nominal capacity for a significant amount of hours, about 3500 hours in the case of -10% and about 4000 hours for the case of -20%. However, it is not certain that it is feasible for the electrolysers to operate over its nominal capacity for such an amount of time. If it proves to be feasible, the degradation and efficiency will be affected which has not been accounted for in this work.

6.3.2 Discount Rate

The discount rate (DR) represents the risk of investing in a project, with a higher rate, the project is exposed to a higher risk. The cost of capital is often used as DR. In the predictions by IEA (2019b), a DR of 8% is used for hydrogen production from electrolysis. Therefore, a DR of 8% is assumed as the base case for the offshore wind power-hydrogen system in this work. However, due to uncertainties about the future, the DR is varied with the purpose to identify the impact on the LCOH results. The market for offshore wind is developing and is expected to develop in the future which will have an impact on the DR. In the period 2020-2021, the cost of capital for offshore wind in Western Europe was in the range of 3-5%, and is predicted to decline in the future as the market evolves (IRENA 2023). The results are presented in figure 19 and 20 where the DR is 4 and 12%, respectively. When varying the DR, the LCOH changes significantly. If the development would decrease in line with the predictions for offshore wind, the LCOH would decrease approximately 25%.

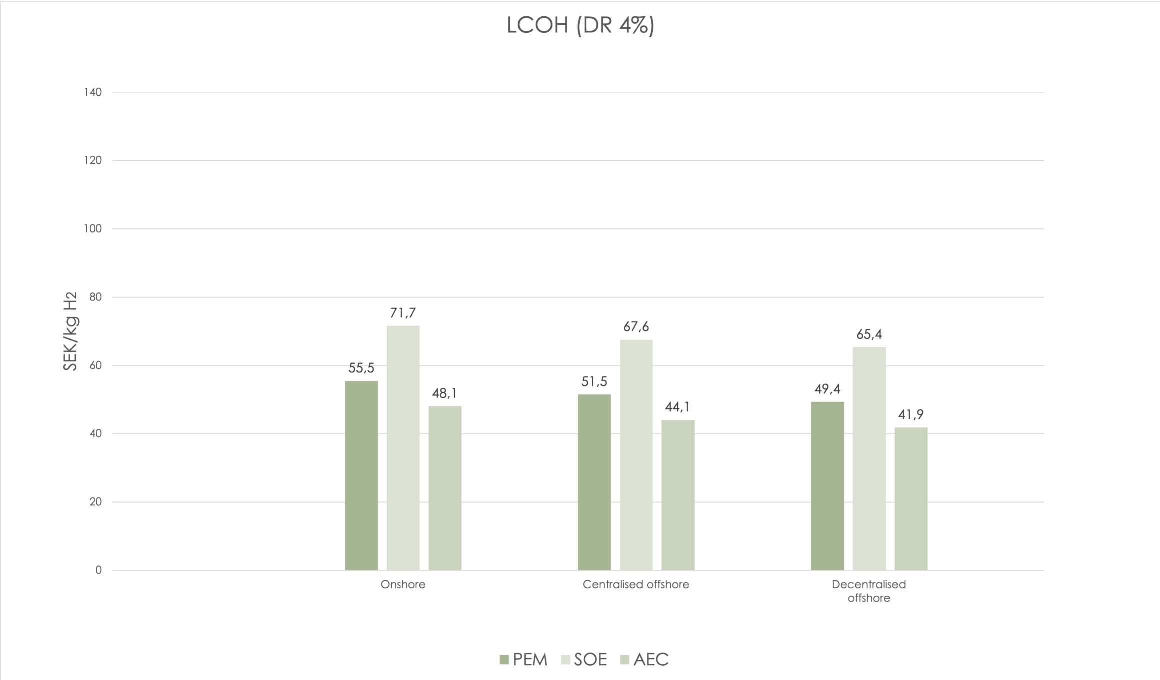


Figure 19: LCOH with discount rate 4%

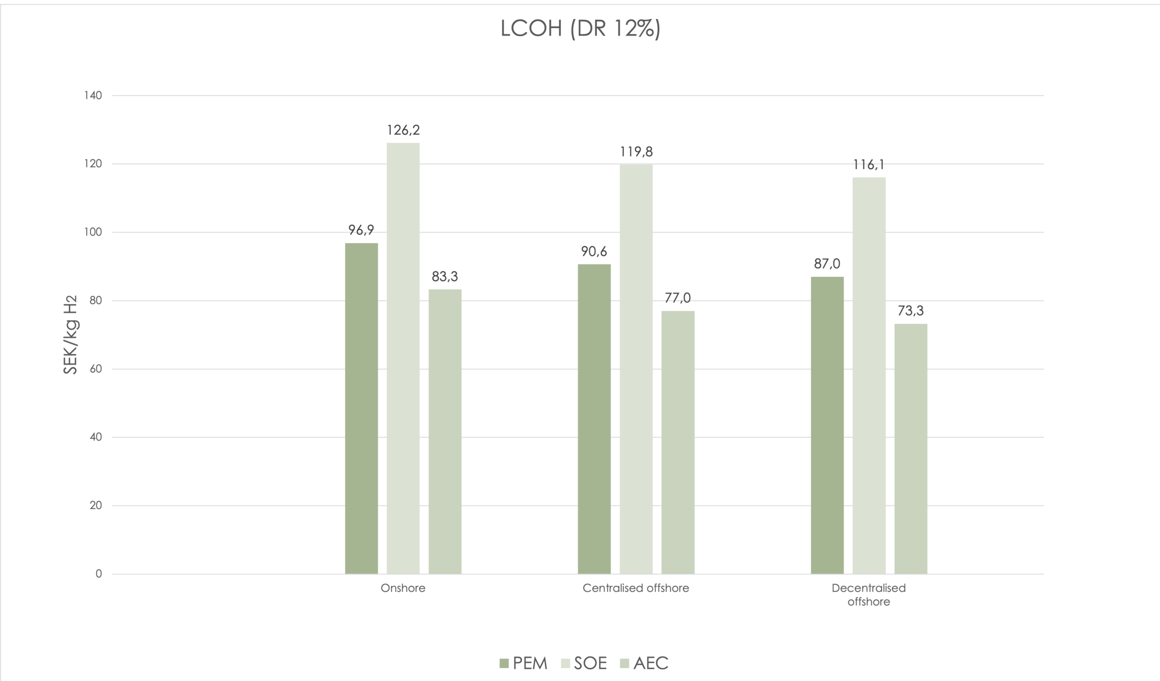


Figure 20: LCOH with discount rate 12%

6.3.3 Operational Expenditures

Seeing that OPEX constitutes a large part of the lifetime cost for the systems, a sensitivity analysis is performed regarding this parameter. The OPEX includes planned and unplanned maintenance and service costs, training and labour costs, logistics both onshore and offshore as well as insurances, environmental studies and inspection. In the base case, OPEX is set to 3% of the CAPEX per year for the OWF and 2% of CAPEX per year for the electrolyser system. Figure 21 illustrates the LCOE when OPEX instead is set to 2.5% for the OWF and 1.5% for the electrolyser system, and figure 22 shows when OPEX is 4% of the CAPEX per year for the OWF and 3% for the electrolyser system, respectively. Figure 23 and 24 presents the same for LCOH. The analysis shows that changing the OPEX by only half a percentage unit will impact the results remarkably. Therefore, the OPEX needs to be evaluated carefully and optimisation of factors as planned maintenance and service are of high priority.

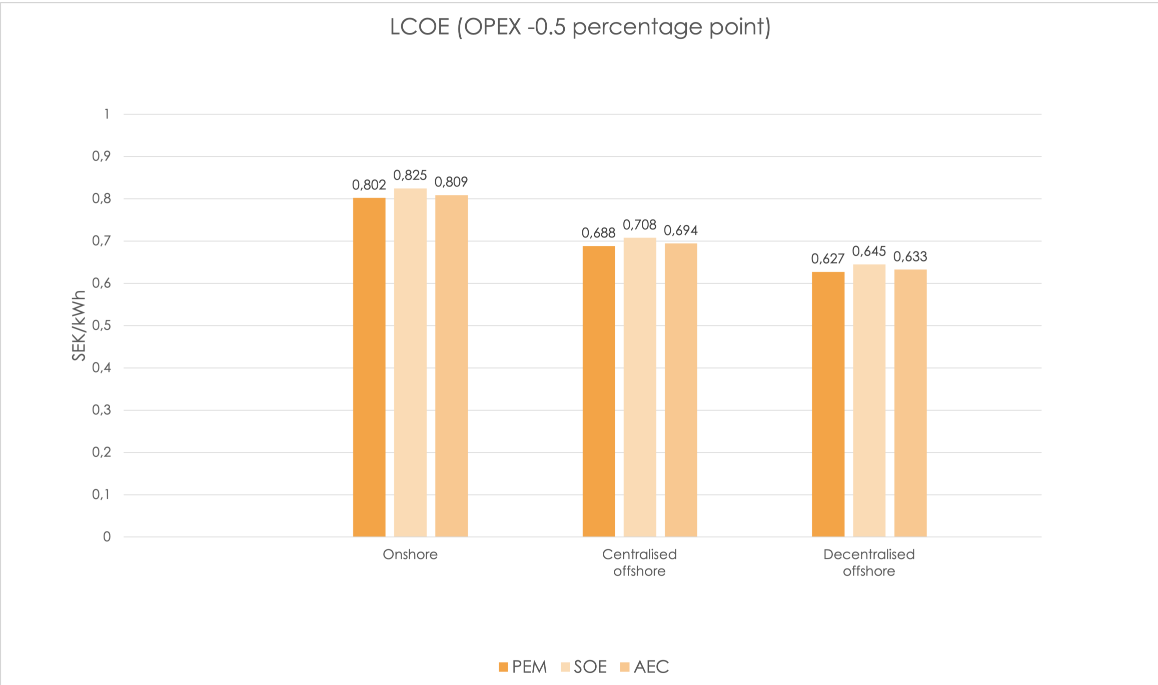


Figure 21: LCOE with an OPEX reduction of 0.5 percentage point per year

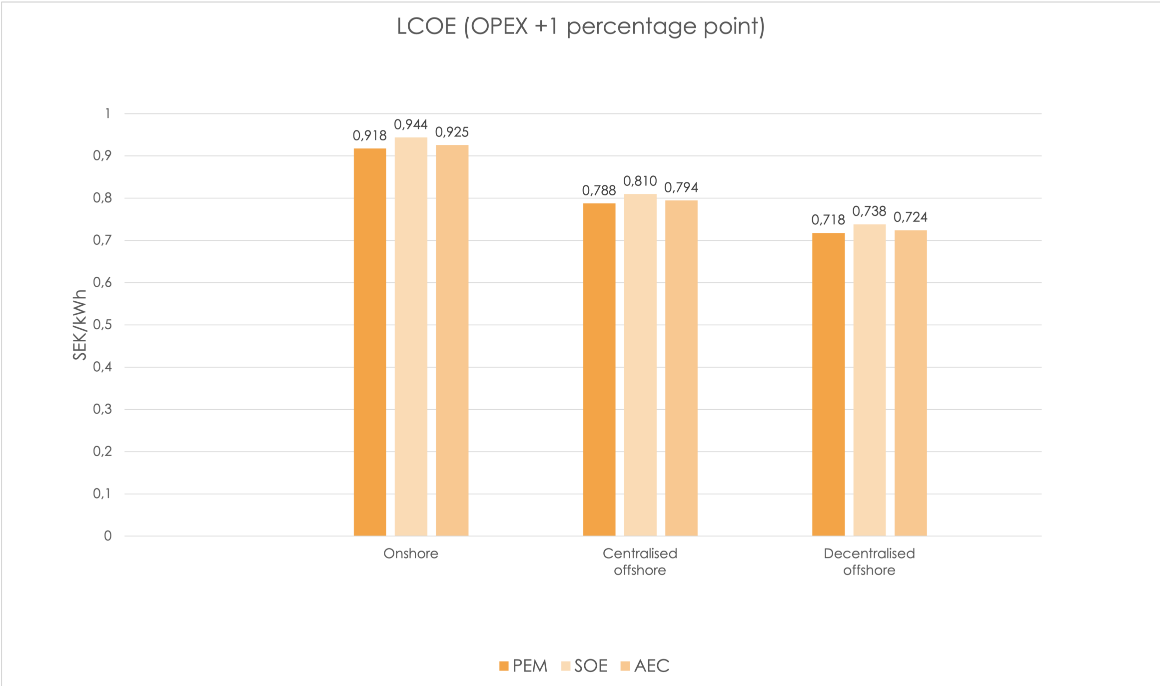


Figure 22: LCOE with an OPEX increase of 1 percentage point per year

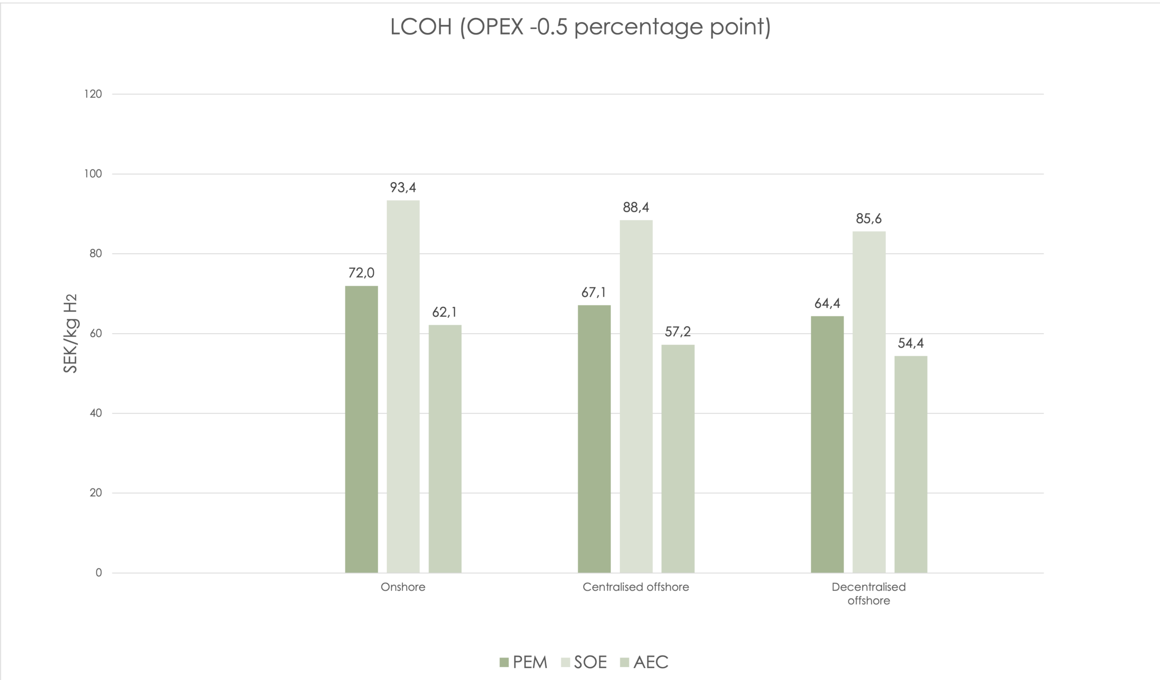


Figure 23: LCOH with an OPEX reduction of 0.5 percentage point per year

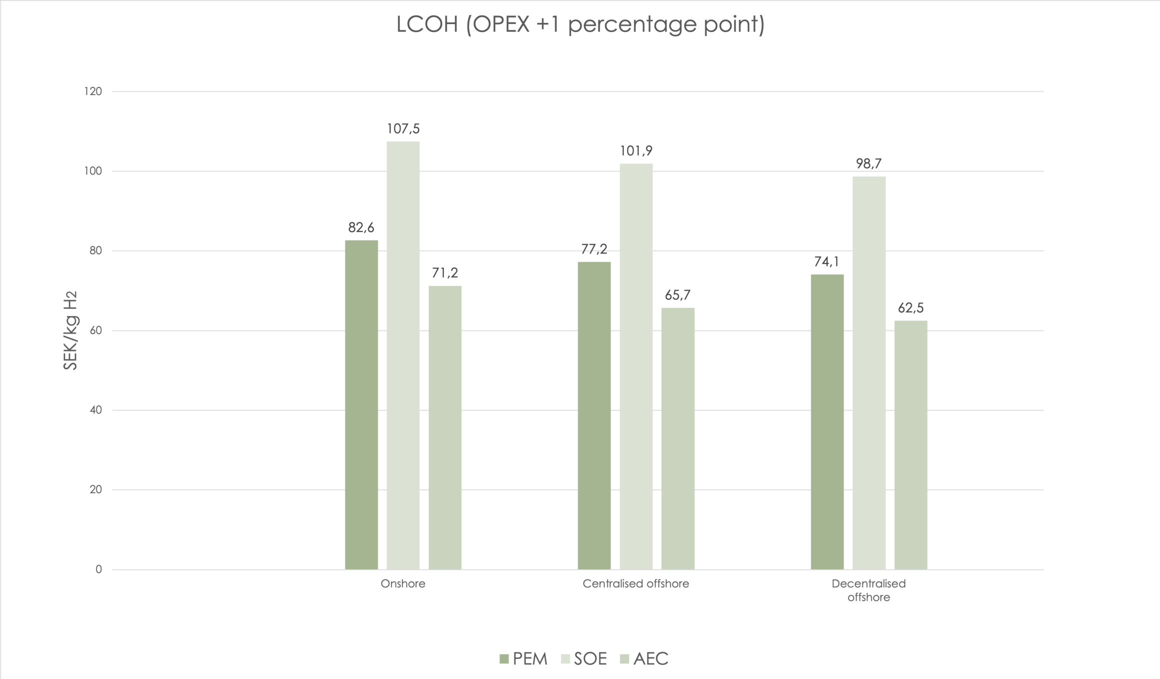


Figure 24: LCOH with an OPEX increase of 1 percentage point per year

6.3.4 Cost of Water

The results indicate that a great amount of water is required when producing hydrogen for 35 years, approximately 0.3 billion m^3. The price difference of buying fresh water and using a desalination unit was found interesting, thus a sensitivity analysis is carried out for further investigation. 50 SEK/m^3 fresh water is set as the price for the base case (Ruderstam 2022). The results are displayed in table 11.

Table 11: Total lifetime cost of water when buying fresh water at different prices or using a desalination unit.

Total lifetime water cost [BSEK]	PEM	SOE	AEC
Water price at 25 SEK/m^3	0.74	0.74	0.73
Water price at 50 SEK/m^3	1.48	1.48	1.46
Water price at 100 SEk/m^3	2.95	2.95	2.92
Desalination unit	0.24	0.26	0.24

The analysis shows that it is significantly cheaper to use a desalination unit for the onshore configuration, rather than to buy fresh water, regardless of which of the water prices considered. Seeing that the water price is anticipated to increase in the future partly due to climate change (Vatten 2017), together with fresh water being an important resource, the results show that it is beneficial to use a desalination unit if feasible.

6.4 Discussion

The LCOE in the onshore configuration was calculated to approximately 0.85 SEK/kWh. This corresponds to the average cost of the generated electricity that could be sold on the electricity market. The profitability of instead selling the electricity on the electricity market is very much dependent on the spot price. In SE4, the electricity area in southern Sweden, the yearly average of the day-ahead prices the last ten years has been as low as 0.257 SEK/kWh (2015) and as high as 1.71 SEK/kWh (2022) (Nord Pool 2023). Further research is required to compare profitability of producing hydrogen versus selling the electricity. One option is to have an offshore wind-hydrogen system that is grid-connected and optimise the operation of this system. It is plausible that an onshore configuration is the most beneficial option when having a grid connection, as the electricity is already reaching the shore without the need of any additional infrastructure for this purpose.

The overwhelming majority of the hydrogen produced today is derived from fossil fuels. As of 2019, only less than 0.7% of the hydrogen production is from renewables or from fossil fuel plants equipped with carbon capture, utilisation and storage, CCUS (IEA 2019a). The price of hydrogen is exposed to great regional variations and its future economics might be difficult to predict seeing that dependent factors varies, such as fossil fuels, carbon and electricity prices. According to IEA (2019a), with hydrogen from natural gas without CCUS costs are expected to range between 10.39 and 20.78 SEK/kg H_2 until 2030, depending on local gas prices. The emission intensity from hydrogen produced from natural gas are approximately 10 kg CO_2/kg H_2 (IEA 2022b). As the results of this work show, the LCOH ranges from 57.1 to 98.1 SEK/kg H_2. Based on these numbers, one way for renewable hydrogen to be cost competitive in 2030 would be if the price for the hydrogen from natural gas increased corresponding to a carbon tax between 3.6 SEK/kg CO_2 and 8.8 SEK/kg CO_2. For comparison, the carbon tax in Sweden 2023 is 1.3 SEK/kg CO_2 (Government Offices of Sweden 2023).

In order for hydrogen produced from renewable sources to become a more economic option, a development of electrolysers is necessary. As of today, the CAPEX of the electrolyser stack constitutes approximately 50 to 60% of the total CAPEX (IEA 2019a). Future cost reductions will likely be allowed by innovation of the technologies themselves such as development of less costly materials for electrodes and membranes, as well as by economies of scale in the manufacturing process where there is a need of larger electrolysers (IEA 2019a). Seeing that both PEM and AEC uses critical materials, a transition away from platinum, cobalt and iridium is of importance to prevent the materials to become a hindrance of up-scaling (IRENA 2020). Today, the stack capacities for PEM and AEC are at a MW-scale, normally up to 1.5 MW and 2.5 MW (Holst et al. 2021) respectively, whilst the SOE is smaller at a kW-scale (IRENA 2020). The technological development approaches stacks with higher capacities and the use of multi-stack systems, necessary for large-scale systems. However, a development of the electrolysers is not considered to be sufficient as many investors and other stakeholders, according to IEA (2019a), is of the opinion that electrolysers are rather waiting for a standardisation and large-scale demand than a further technological development, in order to increase the hydrogen production.

Due to hydrogen being such a versatile energy carrier, it has great potential, and is of importance, to fully decarbonise the energy systems. In several areas of use where natural gas is the common choice, hydrogen is a possible substitute. The steel and chemical industry are in the transition to exchange coal, natural gas or other fossil fuels to hydrogen, which will lead to a notable increase of the demand. A fraction of hydrogen is possible to blend into today's natural gas grid, allowing for it to be used in for instance heating of buildings. However, the current infrastructure is not able to transport endless amounts of hydrogen which prevents the production from a rapid increase. In certain places, the infrastructure might be in need of an expansion to meet the future demand. However, another possible solution is to use existing pipelines. This can be done by repurposing gas infrastructure for hydrogen which would allow for an easier transition from natural gas. However, certain industries are not able to exchange natural gas to hydrogen due to specific qualities of the natural gas needed in particular processes. The use of hydrogen is expected to expand in the transportation and energy sector as well, which will intensify the demand even more.

Even though predictions show that the price for producing hydrogen from fossil fuels is lower than for hydrogen from renewable sources, an up-scaling of clean hydrogen production is necessary to contribute to the energy transition. The European Commission declared, in REPowerEU, the hydrogen strategy in order to disconnect from the dependency on Russian fossil fuels to enhance the ambitions for renewable hydrogen and ensure the energy security.

6.5 Limitations

When predicted values for 2030 could not be found, state-of-the-art values have been used and adjusted with an inflation rate. No adjustment has been made related to learning effect or economies of scale due to lack of information and probable differences between components. The same cost per MW for each electrolyser has been used in the different configuration cases, regardless of the individual scaling of the electrolyser: using several smaller electrolysers in the decentralised case or few large-scale electrolysers in the onshore and centralised case. However, the real cost reduction due to scaling is not expected to be extensive due to the modular design of the electrolysers (Singlitico et al. 2021). The same simplification has been made related to the desalination and compression units, where the scaling might have a significant impact in reality. The energy consumption of the compression unit must also be considered a rough estimation, where the energy required for adiabatic compression was interpreted from a graph.

Regarding efficiencies of the electrolysers, degradation has been considered. However, the variations in efficiencies when operating under different loads of electricity has not been considered, when in reality the system efficiency is load dependent. The efficiency is low when the load is close to the minimum load, as the equipment is in operation but the production is minimal. It is then increasing until around 30% load where it is the highest, and then decreasing towards the nominal efficiency (IRENA 2020).

Another simplification in the calculation is assuming the percentage of OPEX, installation costs and availability to be equal regardless of the configuration and electrolyser type. The need for maintenance will likely vary among the electrolysers, but due to lack of data this has not been confirmed and they have thus been handled equally. It is also plausible that the cost of installation and maintenance would be lower in the onshore scenario than in the offshore scenarios due to easier access of the facility, leading to differences in installation costs and OPEX. Seeing that OPEX represents a large share of the LCOE and LCOH, it is worth to further investigate the components of this cost for a more reliable result.

As a final remark, large scale offshore electrolysis is not yet mature and input values have a high uncertainty due to the rapid technological and economic development in this field. Other factors than the LCOH can be decisive in the choice of electrolyser, such as specific characteristics, and should be evaluated as well. Considering the mentioned uncertainties, limitations and simplifications, the results from this study should only be treated as an indicator in the assessment of the viability of a future offshore wind-hydrogen system in Sweden.

7 Conclusions

The purpose of this work was to perform a techno-economic analysis of hydrogen production from offshore wind power in Sweden. The study has compared three alternative configurations and three electrolyser technologies to identify the most cost competitive scenario as well as opportunities and limitations. The key points concluded from this work are:

- The results from the study showed that the decentralised offshore configuration is the most cost competitive, having the lowest LCOH ranging between 57.1-89.9 SEK/kg H_2, whereas the onshore configuration is the least cost competitive with a range of 65.2-98.1 SEK/kg H_2.
- A larger impact on the result is obtained by the choice of electrolyser technology, where the alkaline electrolyser is the most cost competitive with an LCOH ranging between 57.1-65.2 SEK/kg H_2, followed by the proton exchange membrane electrolyser with an LCOH between 67.6-75.5 SEK/kg H_2 and the solid oxide electrolyser by far the least cost competitive with an LCOH of 89.9-98.1 SEK/kg H_2. However, the solid oxide electrolyser is the least mature technology, which might increase the uncertainty of predictions related to this technology.
- The lowest LCOH, 57.1 SEK/kg H_2, is found using AEC in the decentralised offshore configuration and the highest, 98.1 SEK/kg H_2, is given by using SOE in the onshore configuration.
- Transcending across all electrolyser technologies, the electricity cost constitutes the largest share of their respective lifetime cost, followed by the OPEX. The third largest cost is the electrolyser cost for PEM and AEC and stack replacement for SOE.
- Hydrogen produced from renewable sources is not yet cost competitive against hydrogen from fossil fuels. The future improvement will likely depend on the technological development, carbon taxes and other incentives as well as demand from both industries and other sectors.
- The use of sea water processed in a desalination unit has been shown to be cheaper than to buy fresh water for producing hydrogen onshore.
- The model consists of several simplifications, assumptions and limitations and thus the results should only be considered as an indication of the viability of future hydrogen deployment in Sweden. To strengthen the reliability, further research is needed, discussed in the following section.

Proposed Further Research

The study conducted in this work is in need of further research to complete the found results. In order to make the results more representative for 2030, a study which develops predictions for the cost of all components would be desirable. This work should also be completed with investigations of possible storage solutions and their effect on the LCOH, to be able to assess the viability of the system. Further research about the potential use of repurposed gas infrastructure could be of interest as an option to large storage facilities.

Furthermore, several interesting aspects are to be explored where one would be to include the end use of hydrogen to investigate the demand and possible profitability. In addition, to expand the system with a grid connection could be of interest to asses the impact on the LCOH and the potential for balancing purposes and other ancillary services. By-products of the hydrogen production are residual heat and oxygen which have the potential of being utilized. Research related to the disposal of these products is motivated, having potential environmental benefits and the possibility of becoming an additional source of income.

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A Inventory Costs

Table 12: Expenditure list related to the wind power plant.

Component	Cost	Comment and source
Capital expenditures, $CAPEX_{WPP}$ (MSEK)		
Nacelle	$6.10 \cdot IC_{WT} \cdot N$	(BVG Associates 2019)
Rotor	$2.90 \cdot IC_{WT} \cdot N$	(BVG Associates 2019)
Tower	$1.07 \cdot IC_{WT} \cdot N$	(BVG Associates 2019)
Turbine installation	$0.76 \cdot IC_{WT} \cdot N$	(BVG Associates 2019)
Foundation	$3.29 \cdot IC_{WT} \cdot N$	Foundation type monopile (Bulder et al. 2021)
Foundation installation	$1.52 \cdot IC_{WT} \cdot N$	(BVG Associates 2019)
Offshore substation	$1.83 \cdot IC_{WT} \cdot N$	Includes a platform hosting a transformer (BVG Associates 2019)
Substation installation	$0.53 \cdot IC_{WT} \cdot N$	(BVG Associates 2019)
Cables (inter-array)	$2.96 \cdot L_{int}$	Cost for HVAC cables with voltage 66 kV (Ruigrok et al. 2019)
Cables (export)	$23.62 \cdot L_{exp}$	Cost for HVAC cables with voltage 400 kV, size 1000 mm^2 (Xiang et al. 2021)
Cables installation	$0.0018 \cdot L \cdot IC_{WT} \cdot N$	(BVG Associates 2019)
Development and project management	$1.83 \cdot IC_{WT} \cdot N$	(BVG Associates 2019)
Operations base	$0.046 \cdot IC_{WT} \cdot N$	(BVG Associates 2019)
Offshore logistics	$0.053 \cdot IC_{WT} \cdot N$	(BVG Associates 2019)

Other 1	5.18 $\cdot IC_{WT} \cdot N$	Includes assembly, wind turbine supplier aspects of installation and commissioning, profit, warranty (BVG Associates 2019)
Other 2	3.23 $\cdot IC_{WT} \cdot N$	Includes insurance, contigency (spent) and construct project management (BVG Associates 2019)
Operational expenditures, OPEX_{WPP} (MSEK/a)		
OPEX_{WPP}	3% $\cdot CAPEX$	Includes maintenance and service costs, logistics, insurance, environmental studies, inspections. Adjusted from (BVG Associates 2019).

where IC_{WT} represents the installed capacity of the turbines (MW) which in this study is 20 MW. N represents number of turbines, in this case 55. L represents the length of the cables (km) and L_{int} and L_{exp} more specifically the length of the inter-array and export cables (km), respectively. a means annum. All values which are not future predictions have been adjusted with inflation, using an inflation rate of 2.5% per annum.

Table 13: Expenditure list related to the electrolyser system.

Component	Cost	Comment and source
Capital expenditures of electrolyser system, CAPEX_{SYS} (MSEK)		
Electrolyser (PEM)	11.17 $\cdot IC_{elec}$	Prediction of CAPEX by 2030 (IEA 2019a)
Electrolyser (SOE)	18.70 $\cdot IC_{elec}$	Prediction of CAPEX by 2030 (IEA 2019a)
Electrolyser (AEC)	6.49 $\cdot IC_{elec}$	Prediction of CAPEX by 2030 (IEA 2019a)
Platform	0.91 $\cdot IC_{elec}$	Size of platform is scaled after IC, not specific footprint, due to limited cost data (BVG Associates 2019)
Platform installation	0.53 $\cdot IC_{elec}$	(BVG Associates 2019)

Desalination unit	$0.016 \cdot W_{day}$	Prediction of CAPEX by 2030 (Caldera and Breyer 2017)
Compression unit	$0.057 \cdot IC_{comp}^{0.8335}$	0.8335 is a Scale Factor (SF) (Khan et al. 2021)
Alkaline fuel cell	$0.0015 \cdot IC_{fc}$	(Ferriday and Middleton 2021)
Storage tank	$0.0086 \cdot M_{H_2}$	The tank is scaled to store sufficient H_2 to cover electricity need for 48h during energy shortage (Rajeevkumar Urs et al. 2023)
Electrolyser system installation cost	$0.76 \cdot IC_{elec}$	Assumed same as turbine installation (BVG Associates 2019)
Pipelines	$0.38 \cdot D \cdot L$	(Armiño Franco et al. 2021)
Operational expenditures, OPEX_{SYS} (MSEK)		
OPEX_{SYS}	$2\% \cdot CAPEX$ per annum	The OPEX applies for large-scale electrolyser systems. Electricity and stack replacement is excluded. (Danish Energy Agency 2020)
Stack replacement	$30\% \cdot CAPEX_{elec}$	The stacks are replaced at t_{ON} = n $\cdot OH_{MAX}+1$ i.e. when stack has operated it's lifetime (Danish Energy Agency 2020)
Fresh water	$50 \cdot W_{DES} \cdot m_{H_2,Y} \cdot 10^{-9}$ per annum	Fresh water is purchased in the onshore configuration, using a water price of 50 SEK/m^3 as this is the average price in Sweden (Ruderstam 2022)

where IC_{elec}, IC*comp*, IC_{fc} represents the installed capacity (MW) for the electrolyser, compressor unit and fuel cell, respectively. W_{day} represents the daily water consumption when the system is producing hydrogen at nominal capacity. $M_{H_2,s}$ is the mass of hydrogen the storage tank holds. D is the diameter of the pipeline (cm) and L the length (km). W_{DES} represents the water consumption for each kilogram of produced hydrogen (l/kg H_2), in this work set as 10 when using fresh water. $m_{H_2,Y}$ represents the mass produced hydrogen for year Y. All values which are not future predictions have been adjusted with inflation, using an inflation rate of 2.5% per annum.