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NTNU
Norwegian University of Science and Technology
Faculty of Engineering
Department of Energy and Process Engineering

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A Feasibility Study of Large Scale Wind Powered Hydrogen Production

A techno-economical analysis of green hydrogen production

Bachelor's project in Renewable Energy
Supervisor: Bruno G. Pollet
Co-supervisor: Siri F. Bjerland and Hanne H. Grøttum
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Preface

This thesis is written as the final part of the Renewable Energy Bachelor's degree program at the Faculty of Engineering Science and Technology (IVT), Norwegian University of Science and Technology (NTNU). The problem description was formed in collaboration with TrønderEnergi and our supervisor. The thesis analyzes the feasibility of large scale hydrogen production based on wind-generated energy.

We are ever grateful for the motivation and guidance we received from our supervisor, Professor Bruno G. Pollet. His counsel proved invaluable throughout the semester. Also a special thanks to our external supervisors at TrønderEnergi, Siri F. Bjerland and Hanne H. Grøttum, for providing us with directions and constructive advise. Lastly, we cannot end this chapter at NTNU without thanking Associate Professor Håvard Karoliussen. Without him, the last three years would not have been the same.

Trondheim, 20.05.2021

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Abstract

The times they are a-changin', and the world is currently undergoing a shift from a fossil fuel based way of living, to a renewable and carbon neutral society. Countries all across the globe are heavily invested into the concept of large scale implementation of renewable energy sources such as wind, solar and hydro as part of the process to decarbonize the energy sector. Electricity generated from renewable energy sources will be the dominant source of energy in the coming years, but are unable to solve the problems single-handedly. This is where hydrogen comes into play. As an energy carrier, hydrogen coupled to, and produced from renewables, is able to operate in tandem with the often fluctuating energy source to function as a temporary storage of energy, thus providing an increased energy security. Additionally, hydrogen can be used in sectors that are typically difficult to decarbonize by use of pure electricity, such as the transportation sector, industry and heating.

The objective of this thesis is to perform a techno-economical analysis of large scale hydrogen production, powered from wind-generated energy. To investigate the feasibility of large scale production, a case study is conducted for several scenarios, with the available energy from wind functioning as the base of the calculations. Two different electrolyzer technologies are analyzed; alkaline and PEM water electrolyzers (AWE and PEMWE). They are considered to be the two most mature technologies available in today's market. The scenarios are modelled in MATLAB over an estimated lifetime of 20 years for the hydrogen production facility, and the simulations are based on data collected from literature review. The data collection consists of capital expenditure (CAPEX) and operational expenses (OPEX) for various components, other costs (non-material costs) as well as water and electricity costs. From the cost data, a hydrogen production plant is simulated. The hydrogen production plant is designed and optimized to find the best trade-off between costs and production.

Hydrogen in its natural form has a low volumetric density, and needs to be processed in order to increase the density to be considered a competitive source of energy. Storing large amounts of hydrogen in an energy-efficient and cheap way is difficult. The method of storage chosen for this thesis is by liquefaction. By liquefying the hydrogen, its volumetric density decreases by a factor of 790 compared to its natural gaseous form. The major drawback of liquefaction is the high cost.

The optimal plant design for a hydrogen production facility is found for three scenarios; 1, 3 and 5 TWh of available energy, with the corresponding levelized cost of hydrogen (LCOH) also obtained from the calculations. The reasoning behind the analysis of the three aforementioned scenarios, is to be able to see how the cost of production is affect by a change in plant size as a result of economies of scale. Because PEMWE is considered to be the better suited electrolyzer technology for coupling with intermittent wind-generated electricity, it is used as an example for most of the sensitivity analysis conducted. The largest PEMWE hydrogen facility analyzed resulted in a LCOH valued at 4.71 €/kg, whereas the equivalent AWE system were calculated to 4.31 €/kg. Electricity accounts for roughly 65% of the OPEX, and 40% of the overall cost, and is therefore an important part of the hydrogen production chain. Based on power purchase agreement analysis (PPA), an electricity price of 30 €/MWh is set as an average price of electricity over the 20 years of operation. Discounted payback period for a number of price points are also analyzed. For a sales price of 7 €/kg, the discounted payback period is estimated to be 12 years for the largest PEMWE-based system, and 10.73 years for the largest AWE-based system.

Sammendrag

Det er skiftende tider, og verden gjennomgår for tiden en omstilling fra en levemåte basert på fossile brenselskilder, til et fornybart og utslippsfritt samfunn. Land over hele verden viser handlingskraft i forbindelse med implementering av fornybare energikilder som vind, sol og vann som en del av prosessen for å avkarbonisere kraftsektoren. Elektrisitet generert fra fornybare energikilder vil i fremtiden være den dominerende energikilden, men er ikke i stand til å løse det grønne skiftet på egenhånd, og det er her hydrogen kommer inn i bildet. Som en energibærer, kan hydrogen som produseres av fornybar kraft komplimentere den svingende krafttilførselen fra de fornybare energikildene. Dette gjør at hydrogen kan fungere som en midlertidig lagring av energi, og bidra til en økt energisikkerhet. I tillegg kan hydrogen brukes i sektorer som vanligvis er vanskelige å avkarbonisere ved bruk av ren elektrisitet, som blant annet transportsektoren, industri og til oppvarming.

Formålet med denne oppgaven er å utføre en teknisk-økonomisk analyse av storskala hydrogenproduksjon, drevet av vindkraft. For å undersøke muligheten for storskalaproduksjon gjennomføres det en case-studie for flere scenarier, hvor den tilgjengelige mengden kraft danner grunnlaget for kalkulasjonene. To forskjellige elektrolyseteknologier blir analysert; alkaliske og PEM vannelektrolysatorer (AWE og PEMWE). De anses for å være de to mest modne teknologiene tilgjengelig i dagens marked. Scenariene er modellert i MATLAB over en estimert levetid på 20 år for hydrogenproduksjonsanlegget, og simuleringene er basert på data samlet fra et littersøk. Datainnsamlingen består av kapitalutgifter (CAPEX), driftskostnader (OPEX), andre kostnader (ikke-materielle kostnader) samt vann- og strømkostnader. Fra kostnadsdataene blir det simulert et fullkomment produksjonsanlegg for hydrogen. Hydrogenproduksjonsanlegget er designet og optimalisert for å finne den beste avveiningen mellom kostnad og produksjon.

Hydrogen i sin naturlige form har lav volumetrisk tetthet, og må bearbeides for å øke tettheten og dermed kunne bli vurdert til å være en konkurransedyktig energikilde. Det er vanskelig å lagre store mengder hydrogen på en energieffektiv og billig måte. I dag blir dette normalt sett gjort ved komprimering, men det kan også gjøres ved blant annet omdanning til flytende hydrogen. I denne oppgaven er omdanning til flytende hydrogen brukt som lagringsform. Ved å gjøre om hydrogengassen til flytende form, reduseres den volumetriske tettheten med en faktor på 790.

Ved bruk av modelleringsverktøyet MATLAB, ble det designet et hydrogenproduksjonsanlegg for tre ulike scenarier; ved 1, 3 og 5 TWh tilgjengelig energi. Med dette som utgangspunkt ble de tilhørende hydrogenproduksjonskostnadene (LCOH) funnet. Ved å analysere tre scenarier av ulik størrelse, er det mulig å se hvordan størrelsen på anlegget påvirker totalkostnadene ved produksjonen. Analysen av de største anleggene, koblet opp mot 5 TWh vindenergi, ga en LCOH på 4.71 €/kg for PEMWE-baserte anlegget og en LCOH på 4.31 €/kg for det tilsvarende AWE-baserte anlegget. Elektrisitetskostnadene står for den største andelen av utgiftene ved produksjon, og utgjør omtrent 65% av OPEX og omlag 40% av totalkostnadene. Basert på analyser av kraftkjøpsavtale (PPA), er en strømpris på 30 €/MWh satt som en gjennomsnittspris på strøm i løpet av de 20 årene anlegget er i drift. Tilbakebetalingstiden for en rekke prispunkter analyseres også, og tilbakebetalingstid med en salgspris på 7 €/kg er estimert til å være 12 år for det største PEMWE-baserte anlegget og 10,73 år for det største AWE-baserte anlegget.

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List of Terms

Term	**Description**
Acidic solution	An aqueous solution which has a pH less than 7
Alkaline solution	An aqueous solution which has a pH more than 7
Anode	The electrode where the oxidation occurs
Balance of Plant	Supporting components part of the electrolyzer system
Boil off rate	Evaporation of a liquid due to heat transfer between storage vessel and ambient temperature
Catalyst	A material that increases the rate of reaction in a chemical reaction, without being reduced itself
Cathode	The electrode where the reduction occurs
Conduction	Transfer of heat through a substance
Convection	Transfer of heat through fluids such as gasses or liquids
Corrosion	Irreversible destruction of a material caused by a chemical reaction
Discount rate	The interest rate used to determine the present value of future cash flow
Discounted payback period	The time it takes to to recover the cost of an investment
Electrolysis	An electrochemical reaction that is driven in the forward direction through use of an external energy supply
Electrolyzer	The component where the electrolysis occurs
Energy density	Amount of energy per unit of volume
Enthalpy	Amount of energy within a substance that is available for conversion to heat
Entropy	The measure of a system's thermal energy per unit temperature that is unavailable for doing useful work
Fuel cell	A components that converts hydrogen to electrical energy (reverse electrolysis)
Ion	An electrically charged atom or molecule
Net Present Value	Difference between the present value of cash inflows and the present value of cash outflows over a period of time
Oxidation	Loss of electrons for a molecule, atom or ion
Power Purchase Agreement	A contract between an energy seller and a buyer
Reduction	Gain of electrons for a molecule, atom or ion
Specific energy	Amount of energy per unit of mass

List of Abbreviations

Abbreviation	Description
AEMWE	Anion exchange membrane water electrolysis
atm	Atmospheric pressure
ATR	Auto-thermal reforming
AWE	Alkaline water electrolyzer
BEV	Battery electric vehicle
BoP	Balance of plant
CAPEX	Capital expenditures
CCS	Carbon capture and storage
CGH_2	Compressed gaseous hydrogen
FCEV	Fuel cell electric vehicle
FCH JU	The Fuel Cells and Hydrogen Joint Undertaking
GWh	Gigawatt hours
HER	Hydrogen evolution reaction
ICE	Internal combustion engine
OPEX	Operational expenses
KWh	Kilowatt hours
LCOH	Levelized cost of Hydrogen
LH_4	Liquid hydrogen
LCOE	Levelized cost of Electricity
LOHC	Liquid organic hydrogen carrier
MCEC	Molten carbonate electrolysis cell
MWh	Megawatt hours
NPV	Net present value
NVE	Norges Vassdrags- og Energidirektorat
OER	Oxygen evolution reaction
PEM	Proton exchange membrane
PEMWE	Proton exchange membrane water electrolyzer
PPA	Power purchase agreement
R&D	Research and development
SMR	Steam methane reforming
SOEC	Solid oxide electrolysis cell
STP	Standard temperature and pressure
TWh	Terrawatt hours
VAT	Value added tax

List of Symbols

Symbol	Description
E	Energy [J/kg or Wh/kg]
E_{rev}	Reversible voltage [V]
F	Faradays constant [C/mol e^-]
m	Mass [kg]
p	Pressure [bar]
P	Electric power [W]
r	Discount rate [%]
T	Temperature [K]
vol%	Percentage of the total volume [%]
w%	Percentage of the total weight [%]
z	Number of electrons
$\Delta\overline{g}$	Gibbs free energy [J/mol]
$\Delta\overline{h}$	Reaction enthalpy [J/mol]
$\Delta\overline{s}$	Reaction entropy [$J/K \cdot mol$]

Chemical symbol	Description
e^-	Electron
CO_2	Carbon dioxide
H_2	Hydrogen gas
H^+	Proton (positively charged ion)
H_2O	Water
KOH	Potassium hydroxide
NaOH	Sodium hydroxide
Ni	Nickel
O_2	Oxygen gas
OH^-	Hydroxide (ion)
Ti	Titanium

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1 Introduction

The world as we know it is undergoing a major shift towards a more sustainable way of life. Human-induced climate changes are well established by now, with people becoming increasingly conscious on making the transition from fossil fuels to renewable energy sources. This growing concern culminated in the Paris Agreement which was signed by 191 countries world wide in April 2016 [1]. The agreement established a goal of limiting the global warming to well below 2 °C within this century, compared to pre-industrial levels. Along with a rapidly growing population and an increased energy demand, renewables are expected to play a pivotal role in achieving this goal. By 2050, electricity will be the main energy source, accounting for more than half of the worlds total energy consumption (compared to 21% today), with 90% being provided from renewables [2].

Having an energy supply dominated by renewables is overall a good thing, but brings along certain challenges. The main problem is the intermittent nature of the energy source, where the variable output from renewables like PV (solar) and wind not always matches the demand [3]. These flexibility issues needs to be solved, and hydrogen enters as a promising solution. By utilizing hydrogen as an energy carrier, produced from renewable energy, a substantial amount of energy from renewables can be stored both short and long term. This synergy allows for a reliable and sustainable energy sector, often referred to as the Hydrogen economy [4].

To reach the climate targets, an implementation of renewable energy alone is not enough. There will still be a need to decarbonize applications that are unable to operate purely on electricity, the so called hard-to-abate sectors [3]. Amongst these sectors are transportation, industry and applications that require a high heating grade for operation - all of which are withing the reach of hydrogen's capabilities as an energy carrier. By producing hydrogen electrochemically via water electrolysis, large amounts of renewable energy can be channeled from the power sector into these hard-to-abate end sectors, allowing for a green shift even in the most challenging sectors. [5]

1.1 Application and Demand of Hydrogen

The hydrogen industry is already well established and has been around for decades. Today, around 120 million tonnes (Mt) of hydrogen are being produced annually, with the vast majority being produced and used on-site in industry. The production of ammonia and oil refining are the main purposes for production, accounting for two thirds of the hydrogen use. Close to all of this is produced from fossil fuel based energy sources, with less than 1% being categorized as green hydrogen [2, 3, 6, 7]. In the 1.5 degree scenario, it is estimated a demand of 613 Mt of hydrogen, with approximately two thirds of it being categorized as green. To be able to produce these numbers, almost 5 000 GW of hydrogen electrolyzer capacity will have to be installed by 2050, a significant increase compared to today's installed capacity of around 0.3 GW [2].

Once being produced at a large scale and a competitive cost, green hydrogen can take the leap from small scale industrial application towards a global application. Hydrogen has the advantage of being a highly versatile substance, with the ability to be converted into numerous other energy carriers such as ammonia, as well as methanol, methane and liquid hydrocarbons. As a fuel, hydrogen can be combusted directly in engines and turbines or applied in fuel cells, which is an electrochemical device that combines hydrogen with oxygen to produce electricity, with the only bi-product of either methods being water; zero carbon emission. [8]

Global hydrogen market

Green hydrogen is on the rise, and currently experiencing a lot of momentum, both politically and business-wise. Over the last few years there has been an increasing number of countries that have shown signs of a shift towards the hydrogen economy, with several policies and strategies being put into motion. As of today, there are 228 hydrogen projects announced globally, with 17 of them set out to be giga-scale production projects (i.e. more than 1GW installed electrolyzer capacity), with the biggest ones planned in Europe, Australia, Chile and the middle east [9]. Europe leads the way globally in terms of number of announced project, with over 55% of the globally announced projects currently being located in Europe. [6]

European countries such as the Netherlands and Germany who are facing future electrification limits because of the high share of renewables are amongst the nations that are stepping up their hydrogen commitment. The European hydrogen industry is proposing the installation of a 2x40 GW electrolyzer capacity by 2030 [9]. The installation is proposed to take place in the countries part of the EU, North Africa as well as Ukraine. Especially North Africa are in possession of excellent renewable resources such as solar and wind, and are considered a great option for production of green hydrogen.. The 2x40 GW initiative will make Europe a globally leading industry for clean hydrogen production. Other nations such as Japan, Korea and China are also heavily invested in the hydrogen economy, with Japan being the first country to adopt a “basic hydrogen strategy” and with specific plans to become a “hydrogen society”. The Japanese strategy is especially invested in replacing fossil fuel driven vehicles with hydrogen based vehicles. [3, 6, 10]

Hydrogen in Norway

In Norway, about 225 000 tonnes of hydrogen are produced in the industry - with the majority being used to produce methanol and ammonia. The future demand of hydrogen in Norway is by 2030 expected to remain at today’s level, with 75% of it presumed to be needed for methanol and ammonia production, and the remaining 25% divided between heavy duty vehicles, buses, maritime, trains and new industrial users [11]. The maritime sector is already experiencing an increase in hydrogen-based ferries, and it expected to reach a tally of 70 operative ferries by 2021 [12].

In December 2020, Yara, in association with Statkraft and Aker Horizon, announced plans of creating a green hydrogen-based value chain based in Norway. Their first project will be to replace the ammonia producing facility at Herøya, Porsgrunn, with an electrolyzers system based on renewable energy - thus being able to produce green hydrogen (ammonia). By replacing the already existing non-renewable facility with a green hydrogen production facility, it is estimated that a total of 800 000 tonnes of annual CO_2 emissions will be avoided - equivalent to more than 300 000 fossil fuel-powered cars. The installed capacity at the facility is estimated to be 450 MW, with finalization expected in 2026. This sets the scene for Norway as a producer of green hydrogen. [13]

1.2 Problem Description

With the aforementioned section in mind, it is only natural to try and get a better understanding of what it takes for large scale green hydrogen production to become feasible. With renewables provided from Norwegian wind farms as the starting point, the objective is to analyze the entire hydrogen production chain to see whether or not green hydrogen production is a viable option today. The problem description outlining the scope of the thesis can be compiled into the following: *Is it feasible to produce hydrogen from electrolysis - entirely supplied by wind-generated energy?*

Structure of the thesis

In order to determine whether or not the problem definition is viable, it was decided to conduct a modelling of a complete hydrogen production plant - from hydrogen production to storage. The following steps have been undertaking in order to achieve this:

1. Determine the amount of wind-generated energy that is available for use.
2. Evaluate the current technologies available for hydrogen production.
3. Evaluate different methods for storing hydrogen.
4. Look into the various options for hydrogen delivery.
5. Design a hydrogen production plant in accordance with the initial values and findings from the conducted evaluations and research.
6. Perform a cost analysis to determine the feasibility of the hydrogen production plant.

These are steps which forms the basis of the thesis, with the hopes of providing some valuable insights along the way.

2 Theory

This section of the thesis will present all relevant information related to the thesis. The necessary theoretical background will be established, laying the foundation for understanding the challenges and opportunities related to large scale green hydrogen production.

2.1 Energy From Wind

Wind power is defined as the extraction of mechanical or electrical energy from wind. A growing population, accompanied with an increasing energy demand, poses supply challenges in the energy sector. Wind power is part of the solution in supplying green energy for use in households as well as in the industry. This section will put forward the developments in wind energy technology and economics, establishing its feasibility and role related to green hydrogen production.

2.1.1 Onshore

Since the late 1800's, wind turbines have been used to produce electricity. Incremental developments in wind turbine technology led to the first onshore wind farm almost a century later, in New Hampshire, 1980. Harnessing the available energy from wind has gained priority in the last decades, and has led to a rapidly developing energy sector. [14]

Technological developments

Technological advances have drastically improved onshore wind turbines over the last decades. The turbines which are being deployed today, are larger and more efficient than previous models. Innovations and growing competition among producers are pushing prices down. The developments in the physical size of the turbines contributes to decreasing costs. Figure 2.1 illustrates the average sizes and capacities of onshore wind turbines over the last ten years. [15]

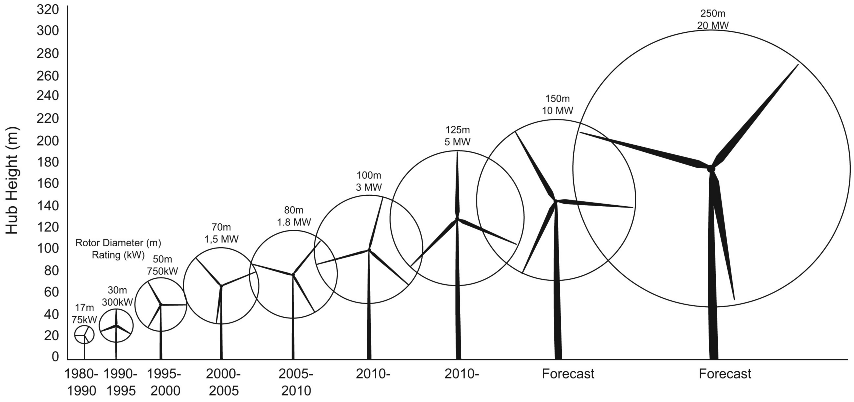


Figure 2.1: The increase of average rotor diameter and capacity [16].

As illustrated, both the average name plate capacity and rotor diameter of onshore wind turbines are increasing. In combination with decreasing installation costs, and a more mature supply chain, these innovations are causing wind energy to be able to compete with traditional energy sources such as coal and nuclear energy.

Cost of onshore wind farms

These developments coincide with a decrease in costs. The costs of constructing onshore wind farms can be divided into four main sections, displayed in Figure 2.2. [15]

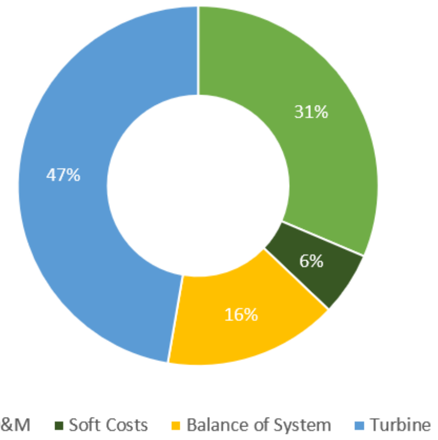


Figure 2.2: Cost distribution in a typical onshore farm [17].

Nearly half the cost of a wind farm, 47%, is used to purchase the turbines. This post includes the tower, hub, and the rotors. O&M, accounting for 31%, are the operational expenses over the 25 year long lifetime of the wind farm. Assembly, electrical components and other infrastructure are compiled into Balance of System, composing 16% of the overall cost. The last 6% are financing and contingency costs. [17]

LCOE in onshore wind farms

These sections are measured as percentages related to the levelized cost of electricity, LCOE. This is a way of comparing costs between different sources of electricity generation. Commonly given in €/MWh, it is a measurement of how much the electricity would need to be sold for, in order for the investment to break even. The LCOE has decreased drastically ever since the installation of the first wind farm in 1980. As the technology is maturing, the LCOE is flattening out. Figure 2.3 displays the expected reductions in the LCOE until 2035.[15, 18]

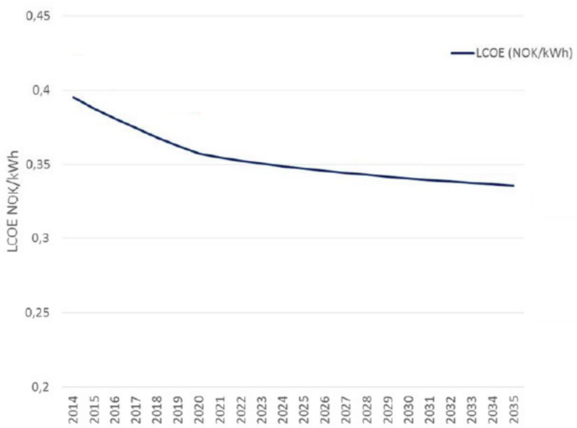


Figure 2.3: Future onshore LCOE developments [19].

Assuming an exchange rate of 10 NOK/€, the onshore LCOE hovers in the area of 35€/MWh. The next fifteen years are predicted to bring costs down even further. However, as a consequence of a maturing technology, the reductions are expected to be limited to 2€/MWh. This LCOE is an estimate based on the Norwegian market, and might differ from other regions. Changes in the LCOE also differ, based on the conditions and location of the wind farm.[15, 19]

Location and public opinion

With an increasing diversity of turbines available, a growing number of locations are available to harness wind energy. Taller towers allow the turbines to reach wind speeds previously unavailable at the same locations. Improvements in computing and sensor technology allow for a better understanding of optimal wind farm location. Developments in noise reduction also allow for turbines to be constructed closer to residential areas. [15]

Any construction project will have an affect on the surrounding environment, and wind turbines are no exception. Depending on the location of the wind farm, the assembly process might require road work or other infrastructure. This might damage otherwise untouched nature. Upon completion, the area where the turbines are erected is not as accessible for hiking or other leisure activities. Depending on the area, wildlife might also be at risk. At Smøla wind farm, Norway, there is a recurring issue of eagles dying as they fly into the rotors. Other countries are experiencing similar outcomes with other species of wildlife. The combination of these factors fuels the ongoing debate of whether climate or nature is to be prioritised. [20, 21]

2.1.2 Offshore

Unlike onshore wind, offshore wind energy is a relatively recent development. The first commercially available offshore wind farm was commissioned in Denmark in 1991. Vindeby consisted of 11 turbines, with an installed capacity of 5 MW. The next decade saw experimental farms being developed in the Netherlands, Sweden, and the UK. Changes in the political climate caused governments to implement policies and incentives to further research and implementation of offshore technology. In 2012, efforts were directed at lowering costs, generating interest in offshore wind across the world. In present day, offshore wind is an economically viable option when expanding, and replacing energy production. [22, 23]

Costs of offshore wind farms

Offshore wind parks, while economically viable, are more expensive than than onshore parks. While turbines cost the same whether they are to be deployed offshore or onshore, the surrounding costs increase. Figure 2.4 show the cost distribution as a percentage of LCOE in offshore projects.[24]

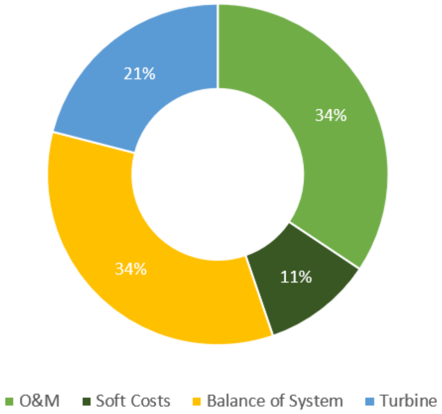


Figure 2.4: Cost distribution in a typical bottom-fixed offshore wind farm [17].

In contrast to onshore wind systems, turbines are not the largest expense when developing offshore wind farms. Operational expenses, O&M, constitutes just over a third of the LCOE. The substructure, foundation, and other infrastructure, are combined under balance of system, which also contributes a third of the costs. The turbine itself only make up 21% of the overall cost. The remainder, soft costs, are expenses related to financing, decommissioning, and contingency. [17]

The turbine makes up almost half the cost in an onshore project, but a fifth in offshore farms. In both offshore and onshore wind farms, the turbine itself costs the same. The cause of the increased LCOE can be explained largely by the increased costs related to installing the wind turbines. Operational expenses are related to the total cost of the project, and share similar percentages of the cost in offshore and offshore wind farms. [17]

LCOE in offshore wind farms

The LCOE in bottom-fixed offshore projects is expected to follow the same curve as its onshore counterpart. Decreasing costs will lower the LCOE, flattening out when the industry matures. Economies of scale, and an increase in the efficiency of the supply chain, drive the costs down. As the market matures, innovations in performance and the manufacturing process will provide the majority of further cost reductions. Figure 2.5 depicts the expected decline in LCOE. [25]

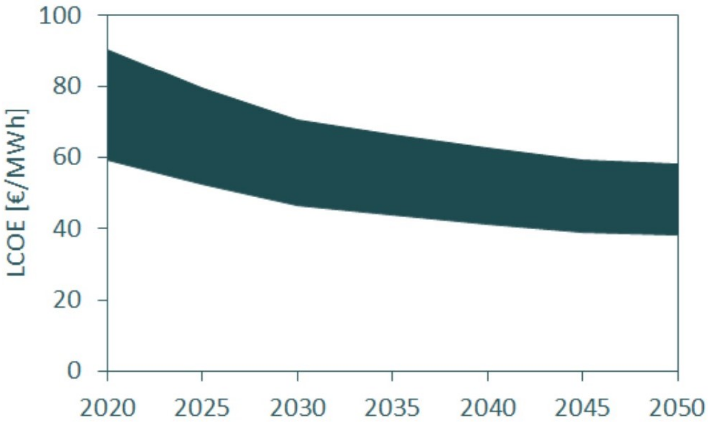


Figure 2.5: Projection of the future decline in LCOE [25].

Over time, wind turbines have increased in both physical size and capacity ratings. In 2007, the average offshore wind park had an installed capacity of 80MW. This increased to 560MW in 2018, and is expected to grow even further. Using fewer, bigger turbines, decreases the amount of fixed foundations needed. Foundations, being the third largest expense, is an important part of making a project cost effective. [17, 24]

Wind farms which are constructed today, generally contain a larger amount of turbines. As every wind park requires base electrical infrastructure, connecting several turbines to the same infrastructure reduces the initial cost per turbine. This, in turn, lowers the LCOE. Maintenance cost of the electrical infrastructure follows the same principle. [17, 24]

The vast majority of offshore wind power is fixed to the sea bed. Fixed foundations are utilized at depths down to 60 meters. Anything deeper requires the use of floating foundations. The technology concerning floating foundations are in a developmental stage, and not yet commercially viable. While the cost of floating foundations are decreasing as more research is being done, it is not yet economically feasible with large scale wind parks. Hywind Scotland has implemented a floating foundation, 100 meters deep, aiming to further research in floating foundations. Future advancements are expected to bring floating wind energy to a cost-competitive level within 2030. [23–26]

2.2 Norwegian Wind Power

Norway's energy demand has historically been almost entirely supplied by hydro power. Hydro still accounts for the majority of energy production today, of around 88%. However, in 2013, hydro power supplied 96%. The reason for hydro powers' decreasing share, is mainly the construction of onshore wind. In the early 2000's, as more commercial wind farms were constructed worldwide, they gradually increased in average capacity. Fast forward to 2020, where wind farms comprise 8.5% of energy production. [27, 28] In 2020, wind farms supplied 13 of the 153 TWh produced in Norwegian territory. In the future, wind will occupy a larger share of the energy production. Currently, there are more than 30 approved concessions undergoing, or planning construction. Totaling at over 2 200 MW capacity, completion will result in more than 50% increase in wind capacity. Most operational wind farms today are located onshore, but offshore wind is expected to increase in the near future. [27–29]

Norwegian wind power potential

Not all areas are equally feasible for producing wind energy. Large areas of Norwegian waters are too deep for fixed foundation wind turbines. Large bodies of water require floating foundations, significantly increasing costs. Figure 2.6 illustrate the mean wind speed in Norwegian territory, along with the water depth. [24]

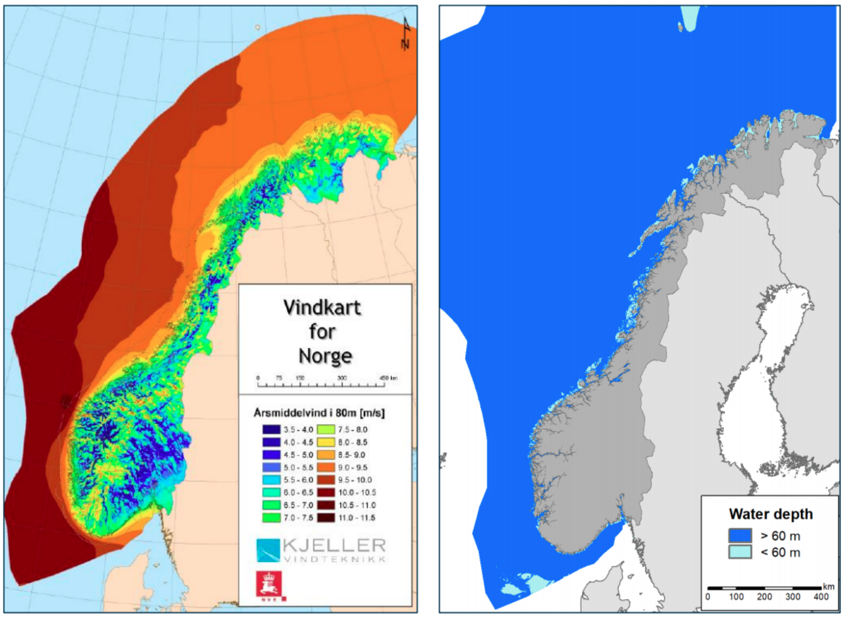


Figure 2.6: Maps of mean wind speed, and water depths in Norwegian territory [26].

Large parts of Norwegian territory have favorable wind conditions. However, the water is often too deep to mount turbines on fixed foundations, requiring floating foundations at depths which are not yet feasible.

The Norwegian Water Resources and Energy Directorate, NVE, assessed Norway's onshore and offshore wind power potential, in 2005 and 2008 respectively. Areas with mean wind speeds of 7 m/s or higher are considered viable areas for installation. The reports calculate available resources in non-protected areas, where construction is currently possible. With a capacity density of 15 MW/km^2, it is estimated that a capacity of over 83 000 MW could be installed in coastal areas. In-land areas are not surveyed to the same extent. Offshore, it was assessed that for depths down to 50 m, an installed capacity between 13 000 and 55 000 MW is possible. If the depth is set to 100 m, the potential increases to between 40 000 and 140 000 MW. The variance in these numbers are caused by the distance from land. The lowest estimates assume a distance of 10 km from land, the highest; 1 km. Combined, more than 243 000 MW capacity is theoretically available in Norwegian waters. As the technology is developed further, larger amounts of offshore resources will be available.

There are, however, a number of factors which would reduce the combined potential. The fishing industry, The Norwegian Armed Forces, or other interests might impact available areas. The process of concession would also unveil other areas where construction isn't viable. As more than half of the land-based potential is in Finnmark, and the largest part of the offshore potential is in Nordland, constructing large wind farms would require large investments into the grid. This strains the economic viability of projects. [30, 31]

Public opinion

Following the construction of wind farms across the country, public opinion has turned critical towards wind power. In 2011, 84% of Norwegians were positive to onshore wind energy. At this time, the total installed capacity was 522 MW. By the end of 2020, this total had increased to just below 4000 MW. During the same time frame, public opinion fell to the point where only 36% of the population expressed a positive view towards onshore wind. The drop in popularity can largely be explained by the negative impact of constructing and maintaining the turbines. Groups opposing the construction of wind farms have increased in number, and protests are a regular occurrence. Offshore wind saw a decrease from 89% to 65% in the same popularity survey. Wind farms constructed offshore does not interfere with nature to the same degree. However, some of the decrease originates from the impact on wildlife. [20, 28, 32]

2.3 Using Wind Energy for Hydrogen Production

Green hydrogen is, by definition, a label on hydrogen production fueled solely by renewable energy. Wind and solar are the two prevailing sources, when looking to produce green hydrogen through electrolysis. Splitting water molecules into hydrogen and oxygen, electrolysis is a process which requires a steady energy supply. [33] In contrast, wind energy production fluctuates on a daily and seasonal basis. This discrepancy poses a challenge when aiming to produce green hydrogen. Total production, divided by the theoretical maximum, is called the capacity factor. The average capacity factor of Norwegian wind farms is 37.4%. Thus, a hypothetical Norwegian wind farm capable of producing 100 GWh yearly, would likely produce close to 37.4 GWh. Figure 2.7 displays the fluctuating nature of wind energy production. [28]

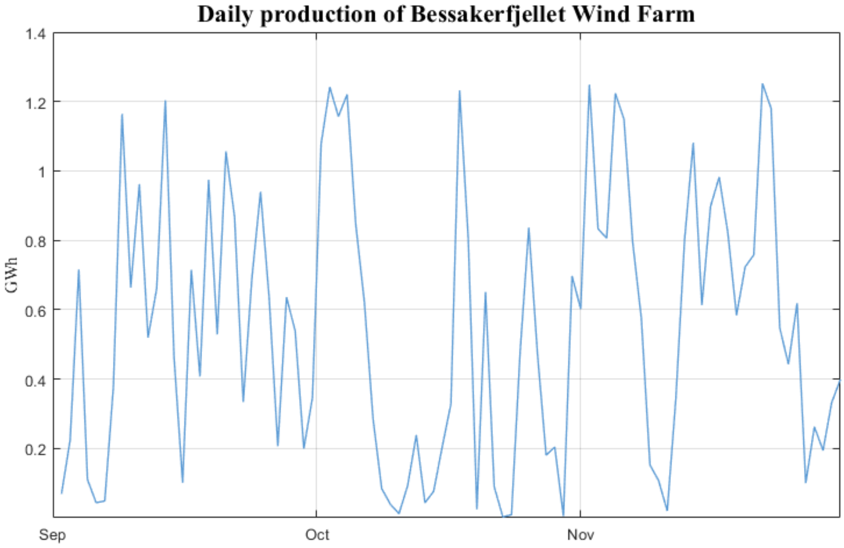


Figure 2.7: Daily production from Bessakerfjellet in the fall of 2020 [28].

Bessakerfjellet is a wind farm located in Åfjord, Norway. The production curve of the farm's 25 turbines, display the challenge in maintaining a steady supply of power. The installed capacity of Bessakerfjellet is 57.5 MW, meaning that under optimal conditions, it would supply 1380 MWh every day. Nevertheless, the realities of wind make this an impossibility. Production can be anything between 0 and 1380 MWh. [28, 34, 35]

Despite these fluctuations, using wind-generated energy as base for hydrogen production, are considered a future necessity. Having laid out the goals for green hydrogen to replace fossil fuels in hard-to-electrify sectors, European countries need to ramp up production to meet these goals. In the European marked, the EU labels the various forms of hydrogen production. The European energy mix, being only 15% renewable, have emissions exceeding the limits set by EU. This means that hydrogen based on electricity from the European grid is not categorized as green. In order to be labeled green, renewable sources needs to be utilized. [36–38]

2.4 Hydrogen as an Energy Storage Medium

Hydrogen is the simplest and most abundant element on earth - consisting of one proton and one electron. The atom does generally not exist in a free state, and is most commonly found in compounds such as water, natural gas and coal, or biomass [39]. This makes hydrogen, like electricity, an energy carrier rather than an energy source. In order to isolate and extract hydrogen from its compound, an external energy source must be applied. The method of separation determines the overall environmental impact of hydrogen, as will be discussed in chapter 2.5. The process requires a substantial amount of energy, but will result in an energy carrier with the potential to deliver and store large amounts of energy. [40]

$$2H_2 + O_2 \rightarrow 2H_2O + \text{electricity} + \text{heat} \tag{2.1}$$

The energy stored in hydrogen can be extracted by combustion or through an electrochemical process, like the one occurring in a fuel cell. The only bi-product from combustion is water and heat, as shown from equation 2.1. When produced from renewables, hydrogen can be considered an emission-free energy carrier. [41]

2.4.1 Properties of Hydrogen

In addition to being a potential emission-free energy carrier, hydrogen also possesses several other favourable properties, with the main one being its high energy density. Compared to other fuels such as gasoline and diesel, hydrogen is able to deliver nearly three times the energy content per kg, 33 KWh/kg versus 13 KWh/kg for gasoline [42]. On a volumetric basis however, the situation shifts. Hydrogen is a gas with very low volumetric energy density at standard temperature and pressure (STP), and must be processed in order to increase its volumetric density. There are several ways of doing this, with the two most common methods being by liquefaction or compression. The processing increases the volumetric density, but comes at a significant cost. From Table 2.1, the importance of hydrogen processing becomes obvious. The difference in volumetric density of hydrogen at atmospheric pressure (1 bar), to compressed (700 bar) and liquid is substantial, and increases the density by a factor of 593 and 790 respectively. [39, 42, 43].

Technology	KWh/kg	MWh/m^3
Li-ion battery	0.19	0.56
Hydrogen, 1 bar	33	0.0027
Hydrogen, 700 bar	33	1.6
Hydrogen, liquid	33	2
Gasoline	13	9
Diesel	13	10

Table 2.1: Overview of specific and volumetric energy density [44].

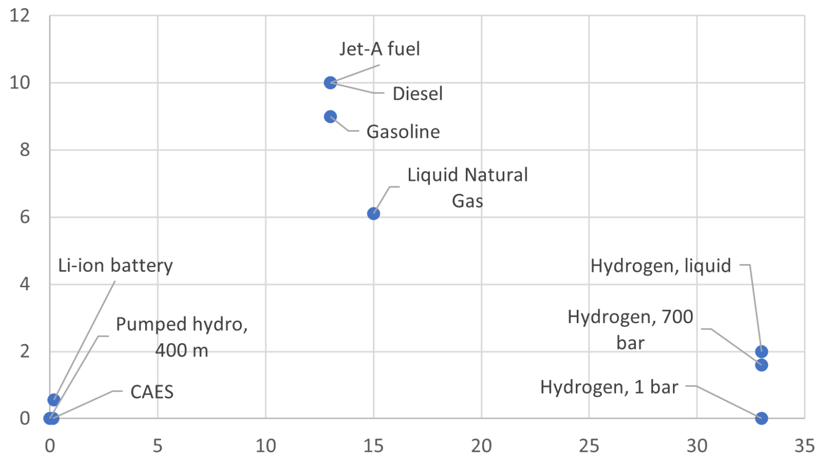


Figure 2.8: Graphical overview of the specific and volumetric densities. [44].

Figure 2.8 provides a graphical overview of the volumetric and specific energy density of a selection of fuels, some of which were presented 2.1. The chart illustrates the large potential of hydrogen as an energy carrier, as a result of its high specific energy density. However, from a volumetric point of view, the fuels based on hydrocarbons (jet A, diesel and gasoline) are considered to be the better alternative. [44]

2.4.2 Application of Hydrogen

As an energy carrier, hydrogen has a wide range of possible end-use applications that can be categorized as stationary, mobile, backup or speciality. Some of the most promising include the following:

Enable renewable energy integration

Using hydrogen for grid balancing is an interesting concept that revolves around a power-to-hydrogen conversion. By producing large amounts of hydrogen at times when the energy supplied from the renewables surpasses the demand, it is possible to store energy that would otherwise be lost. The stored hydrogen can later be used to provide backup during energy deficits, thus offering the ability to adjust the energy output from renewable energy sources to accommodate demand. This can also help provide long-term seasonal flexibility in the energy sector. [6, 45]

Additionally, by shipping green hydrogen over longer distances, it allows for a global distribution of the stored renewable energy This will become increasingly important with a growing share of renewable energy sources. Some countries do not have the ability to generate energy with wind or solar alone, and are dependant on import to supply the needs. Others may not have the required resources needed to fund expensive renewable projects, and will therefore need external supply. Furthermore, it can help bridge the gap between off-grid based energy production and the point of utilization by transportation of hydrogen, rather than electricity. This allows for a more flexible distribution network, without the need for grid connection. [45]

Industry

It is expected that the first step of integrating green hydrogen will be in large industrial sectors, where hydrogen produced by fossil fuels have already been used for decades (refineries and ammonia production). Ammonia is used mainly as a fertilizer or for production of other chemicals, whereas refineries utilize hydrogen for production of fuel from heavy oil [8]. By replacing the fossil-fuel-based hydrogen with green hydrogen in these sectors, emissions of around 830 million tonnes of carbon dioxide per year would be avoided, equivalent to the CO2 emissions of the United Kingdom and Indonesia combined [46].

Transport

Fuel cell electric vehicles (FCEV) is expected to have an important role to play when it comes to decarbonizing the transportation sector, which today accounts for around 24% of the global CO2 emissions [47]. FCEVs offer many of the same abilities as conventional vehicles, such as the internal combustion engine vehicles (ICE). One of them is the ability to drive for longer distances without having to refuel - up to 500 km, as well as a short refueling time of only 3-5 minutes. The battery electric vehicle (BEV) is another interesting source of comparison to the FCEV. Because of the high specific energy density of hydrogen compared to the Li-ion batteries, the FCEV can be considered as complementary to the BEVs as a low-carbon mobility option. FCEV has the ability to reach high utility segments such as long range and high utilization vehicles like busses, trucks, trains and ferries, which are areas where todays batteries are struggling to reach. The application of hydrogen, or hydrogen-based synthetic fuels, is also being heavily research for use in shipping and aviation. Both are in the developing and demonstration stages, but are showing promising signs of rapid development. [8, 45]

2.5 Different Colors of Hydrogen

Producing hydrogen can be done in a number of ways. These processes utilize different sources of hydrogen, with various technologies, costs, and environmental impacts attached. The hydrogen is color coded, to easily distinguish between the differing methods. [38].

2.5.1 Brown Hydrogen

Brown hydrogen is extracted from coal. This process of producing hydrogen is called coal gasification. Coal is heated up before a controlled stream of oxygen is added. This produces a mixture of hydrogen, carbon monoxide, and carbon dioxide. Water reacts with the carbon monoxide, resulting in more hydrogen and carbon dioxide being produced. Separation of the gases allows for pure hydrogen to be extracted on demand. [38]

19 tonnes of CO_2 is released into the atmosphere for every tonne of hydrogen produced, making this a highly pollutive process. Largely due to China's abundance of coal, brown hydrogen makes up 23% of worldwide production. At the same time, brown hydrogen is amongst the cheapest methods to produce hydrogen. The costs of producing brown hydrogen are as low as 1.3 € per kilogram of hydrogen. [38, 48]

2.5.2 Grey Hydrogen

Grey hydrogen refers to hydrogen that has been produced from natural gas. In 2019, grey hydrogen made up 76% of total worldwide hydrogen production. Grey hydrogen production is divided between three main methods. One of the methods is production by Steam Methane Reforming, SMR, where water acts as both the oxidizing agent as well as the source in which hydrogen is being extracted from. The second method for production is by Partial Oxidation, POX, where oxygen is extracted from the air to be used as an oxidizer. Lastly, there is Autothermal Reforming, ATR, a combination of the two aforementioned methods. SMR is the dominant method of producing hydrogen from natural gas, although some plants utilize ATR. [38]

An average of 10 tonnes of CO_2 is released for every tonne of hydrogen produced. As grey hydrogen makes up the majority of worldwide production, the hydrogen industry as a whole is a sizeable emitter of climate gases. The cost of producing grey hydrogen, excluding carbon tax, is 1.5 €/kg. More than two thirds of the cost is due to the cost of natural gas. [33, 38]

2.5.3 Blue Hydrogen

Blue hydrogen is seen as a stepping stone between hydrogen production based on fossil fuels and green hydrogen. Blue hydrogen is produced by extracting the hydrogen from fossil fuels, before capturing the released gases. Carbon Capture and Storage (CCS) technology captures the carbon that would otherwise have been released. This carbon is then stored underground, or used in industry. [38]

As discussed, the vast majority of hydrogen is produced from fossil sources, most notably natural gas. In the process of decreasing the worlds dependency on fossil fuels, blue hydrogen may be a part of the solution. Production of blue hydrogen allows for a continued extraction of natural gas, but with the benefit of a significant reduction in accompanying the climate gas emissions. Up to of 90% of the related emissions can be removed when CCS is applied to brown and gray hydrogen production. [38]

Hydrogen production presents an attractive opportunity for utilizing CCS technologies. Including CCS in the production chain increases production costs, however these increases are relatively small. Especially brown hydrogen production allows for CCS integration with minor impact in terms of efficiency losses and cost increases [38]. Applying CCS to brown and grey hydrogen production increases the cost from 1.3 to 1.6 €/kg, and, 1.4 to 2 €/kg, respectively. In a low-carbon economy, blue hydrogen will remain as the most cost effective method in the near term. [33, 38]

2.5.4 Green Hydrogen

Green hydrogen refers to hydrogen production fueled solely by renewable energy, mainly wind, solar, and hydro. This minimizes the emission of climate gases, and thereby its climate footprint. Currently, less than 100 000 t of the 70 Mt total dedicated hydrogen production, stem from renewable sources [3, 38]. Access to renewable energy is the largest limitation in green hydrogen production. Challenges in maintaining a steady supply, and the increased cost accompanying renewable energy, leads to an increase in the hydrogen production costs. The European Commission estimates green hydrogen to cost between 2.5 and 5.5 €/kg. This is expected to be reduced in the near future due to factors such as technological developments, economies of scale, and incentive programs. Estimated retail prices for liquid hydrogen ranging from 7.1 to 14 €/kg. Prior to closing down, HYOP, a Norwegian hydrogen distributor, operated with a hydrogen price around of 9 €/kg. [33, 49, 50]

With low electricity prices, green hydrogen costs are comparable to those of blue hydrogen. However, present day prices are generally not competitive when compared to fossil fuel-based hydrogen production. Figure 2.9 illustrates an example of how green hydrogen production costs can be reduced by 80% in the long term. [3]

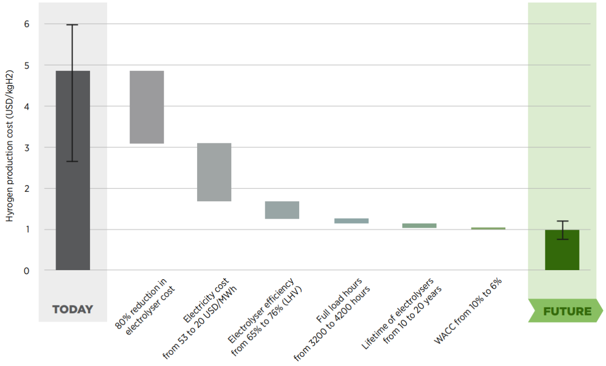


Figure 2.9: IRENA analysis of necessary cost reductions [3].

The figure shows the necessary reductions needed in order for green hydrogen to be considered competitive with the other methods of production. The majority of the reductions are expected to be in the cost of electrolyzers and electricity. If a swift up-scaling of worldwide electrolyzer capacity takes place, it is expected that green hydrogen will be cost-competitive with blue hydrogen in most countries by the end of the decade. The cost of electricity, however, is difficult to predict. Therefore, it is not given that green hydrogen will be able to compete in the near future. [3, 51]

2.6 Water Electrolysis

There are a variety of methods available for performing water electrolysis, but the fundamental principles are the same; water being split into hydrogen and oxygen using electric work, as shown in equation 2.1. Of the five commercially developed technologies, only Alkaline water electrolysis (AWE) and Polymer exchange membrane (PEMWE) will be included in this thesis, both being considered as mature technologies available for large scale industrial use. Other technologies like Solid Oxides electrolysis cell (SOEC), Anion Exchange Membrane water electrolysis (AEMWE) and Molten Carbonate electrolysis cell (MCEC) are still in developing stages, and lies outside the scope of this thesis. [44, 52]

$$\text{Overall: } H_2O + \text{electric work} \rightarrow H_2 + \frac{1}{2}O_2 \tag{2.2}$$

To realise how much electric work is required to dissociate water into H_2 and O_2, it is important to get an understanding of the thermodynamics behind the process. The standard potential of the water electrolytic cell can be found from the oxidation half-reaction occurring at the anode (positively charged electrode) and is equal to -1.23 V at standard temperature and pressure, STP. This is the reversible potential, or the minimum amount of energy required by the system in order for the electrochemical reaction to occur. The reversible potential is equivalent to Gibbs free energy of formation, which can be found by isolating E^{rev} in equation 2.3. At STP, $\Delta\overline{g} = 237KJ/mol$, z is the number of moles of transferred electrons per mole of product, and F is the Faraday constant. Because $\Delta\overline{g} < 0$, the reaction is non-spontaneous and in need of an external energy source to proceed in the forward direction. [44, 53]

$$\Delta\overline{g} = -zFE^{rev} \tag{2.3}$$

The Gibbs free energy is the ideal, reversible potential of the cell. In reality, one has to account for additional losses and irreversibilities. By examining the reaction enthalpy, $\Delta\overline{h}$, shown in equation 2.4, the actual value needed to initiate the reaction can be obtained, known as the thermoneutral voltage. The value for $\Delta\overline{h}$ is found from the Gibbs free reaction energy and the irreversible thermal losses, $T\Delta\overline{s}$. At STP, the value for $\Delta\overline{h}$ is $286KJ/mol$. This gives a value for the thermoneutral voltage of $-1,46$ V. [53, 54]

$$\Delta\overline{h} = \Delta\overline{g} + T\Delta\overline{s} \tag{2.4}$$

$$E^{cell} = E^{rev} - rj - \eta \tag{2.5}$$

In addition to the thermoneutral voltage required, more electric energy is needed to overcome friction in the form of ohmic resistance, rj, where j is the current density (current divided by the electrode surface area) as well as Tafel friction, η, which is caused by electron transfer at the electrodes. Both the ohmic losses and the Tafel overpotential increase with current density, and may be regarded as causes of inefficiencies in the electrolytic cell. The magnitude of the aforementioned irreversible losses depend on the electrolysis technology, but the common denominator is that they will contribute to an increased minimum cell voltage, E^{cell}, as shown in equation 2.5. In general, the cell potential of an electrolyzer will be within the range of 1,8 - 2,4 V at STP, as opposed to the ideal scenario of 1.23 V. [53, 54]

2.6.1 Alkaline Water Electrolysis

The Alkaline water electrolyzer is a well matured and commercially available technology, which has been widely used since the early 1920s. The AWE is characterized by having two electrodes immersed in an alkaline aqueous solution, separated by a diaphragm as shown in Figure 2.10.

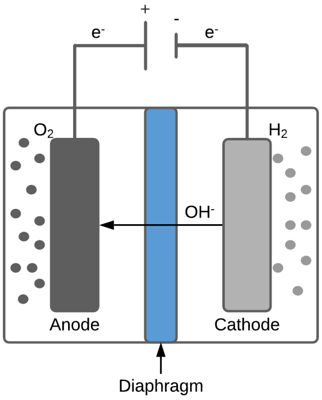


Figure 2.10: Alkaline water electrolysis, based on illustrations from [55].

The electrochemical processes taking place at each electrode can be expressed by two half-cell reactions, as shown in equation 2.7 and 2.6. At the anodic side (positively charged electrode), hydroxide ions are consumed and oxidized to form oxygen and water, while releasing electrons. At the cathodic side (negatively charged electrode), water molecules are being reduced to form hydrogen and hydroxide ions, OH^-, thus completing the redox-coupling. An essential part of the water electrolysis cell is the diaphragm. It functions both as an ion conductor; leading the OH^- - ions from the cathode to the anode, an electrode separator - to prevent the electrodes from shortening out each other, as well as separating the product gases (O_2 at the anode and H_2 at the cathode) to prevent them from being mixed. The latter is important both for safety measures as well as the overall efficiency. Porous diaphragms based on asbestos was heavily utilized up until its ban in the 1970's, due to health hazards. Various diaphragm materials have since been developed, for example the inorganic ion-exchange-type membrane. [44, 54, 56]

$$\text{Cathode: } 2H_2O + 2e^- \rightarrow H_2 + 2OH^- \tag{2.6}$$

$$\text{Anode: } 2OH^- \rightarrow H_2O + \frac{1}{2}O_2 + 2e^- \tag{2.7}$$

The alkaline, aqueous solution in which the electrodes are submersed in, are typically potassium hydroxide (KOH) or sodium hydroxide (NaOH), with a concentration of approximately 20-30 wt%. The use of an alkaline solution is necessary to provide the ionic conductivity between the electrodes, because water by itself possesses poor conductive abilities. Electrodes are usually based on materials made of Nickel (Ni). Either in the form of Ni-coated steel or Ni-oxides. The electrodes must be able to avoid corrosion from the alkaline solution, as well as being conductive in order to minimize the electric resistivity (ohmic losses) in the cell. [54]

The AWE is considered a durable and readily available technology, with relatively low capital investment cost (CAPEX) due to cheap electrode materials, and a mature cell-design with well established components [54]. There are, however, several issues regarding the AWE that are in need of further research and development. The main issues are the limited current density, low operating pressure and a slow loading response, resulting in a poor ability to handle a dynamic operation with fluctuating energy supply. These are factors which contributes negatively in terms of overall efficiency, production cost and cell-design. Not being able to handle a fluctuating energy supply is an issue when paired with intermittent renewable sources such as energy from wind, which is why AWE are normally used with a steady energy input. [53, 54, 56, 57]

2.6.2 PEM Water Electrolysis

In the 1960s, the proton exchange membrane (PEMWE) was introduced as an alternative to the already well established AWE. The main purpose was to try and overcome some of the drawbacks of the AWE, as mentioned in the previous chapter [53]. The PEMWE uses a solid polymer electrolyte known as a membrane, as shown in Figure 2.11. This means that there are no need for any liquid electrolyte, which makes up an less complicated structure with fewer moving parts compared to that of the AWE. [53, 58]

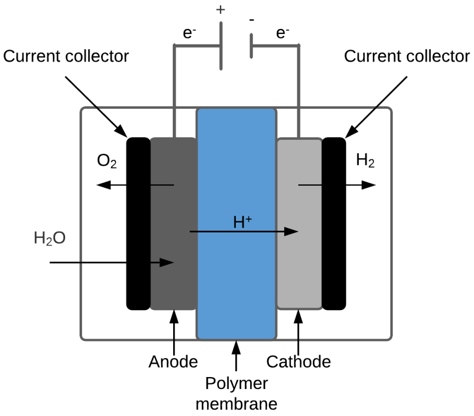


Figure 2.11: PEM water electrolysis, based on illustrations from [55].

The electrochemical processes that are taking place in the PEMWE, is split into two half-reactions, very much like it is for the AWE. At the anode, water is being split into oxygen, protons (H^+) and electrons by application of a voltage that exceeds the thermoneutral requirement (1.428 V), as shown in equation 2.9. The proton passes through the solid polymer membrane towards the cathodic side, where it combines with a free electron to form hydrogen gas, as shown in equation 2.8. [58]

$$\text{Cathode: } 2H^+ + 2e^- \rightarrow H_2 \tag{2.8}$$

$$\text{Anode: } H_2O \rightarrow \frac{1}{2}O_2 + 2H^+ + 2e^- \tag{2.9}$$

The key component in the PEMWE is the polymer electrolyte membrane. Most commonly used is the Nafion membrane, which has a structure that allows for proton exchange as well as some water to pass through it. The level of humidity is controlled within the cell in order for the membrane to operate at its peak efficiency. The membrane, high voltages and the oxygen evolution reaction (OER) at the anode, causes an acidic and harsh environment on the anodic side. This puts extra demands on the quality of materials used in the electrode/catalyst. Titanium (Ti)-based materials, noble metal catalysts and protective coatings are used to provide the necessary durability [3]. The electrodes are made up of thin, porous layers and are placed on each side of the membrane to make the central part of the PEM cell, also known as the membrane electrode assembly (MEA). The product gases that are produced at the anode and cathode, are formed on each side of the MEA, and are removed by flowing water passing through the compartment. This allows for an efficient extraction of hydrogen and oxygen as well as making sure the gases remain separated. The gas production rate happening at the cathode and anode can be accurately adjusted to meet the demands at the production site by stacking cells together. This is usually done in series, and an assembly of cells is called a stack. A combination of stacks is known as a module. [3, 44, 57, 58]

Some of the key advantages of a PEMWE include the capability of functioning with high current density and a high operational pressure. This results in pure, pressurized hydrogen as a product. Additionally, the PEMWE are able to operate flexibly with a rapid startup response [54]. The disadvantages is the high cost of the membrane and the electrodes/catalysts which requires use of noble and expensive materials [56]. Another concern is the need for pure feed water. Impurities in the feed-water will lead to contamination of the electrodes/catalysts and a loss in efficiency. [3, 59]

2.6.3 Alkaline vs PEM

By looking at a comparison between some of the key characteristics and features of the AWE and PEMWE, it is easier to get an understanding of where the competing technologies has its advantages and disadvantages in relation to each other. These are important aspects when deciding which electrolyzer to choose in any given project.

Operational data

Both the AWE and the PEMWE use a moderate operational temperature, which means there is little to no need for any external heating source during production. Two important differences is the cell pressure and the current density, as show in Table 2.2. A high voltage lowers the efficiency in the stacks, whereas a high current density increases the H_2 production volume. This relationship is crucial in terms of determining the overall efficiency and production capacity of the electrolyzers. PEMWE can operate at much higher current densities which leads to a reduction in the operational costs and potentially also the overall cost of electrolysis. [53]

Characteristics	Alkaline	PEM
Operational temperature	70-90°C	50-80°C
Cell pressure	<30 bar	<70 bar
Current density	0.2-0.8 A/cm^2	1-2 A/cm^2
Cell voltage	1.4-3 V	1.4-2.5 V

Table 2.2: Operational figures. [3, 8, 56]

Another important factor is the cell pressure of the electrolyzers. A higher operational pressure enables a reduction in the energy consumption during electrolysis [60]. Additionally, having a higher operation pressure yields a higher final delivery pressure of the product gases. Having a higher output pressure can help maximizing the efficiency and minimize the cost. If the output gases are not sufficiently pressurized, there will be need for an additional compression. This can limit the speed of the production as well as contributing to an increase in cost (compression stages up to 30 bar is especially expensive compared to from 30 bar an upwards). As a result, the compression stage has the potential of becoming a possible bottleneck in the production chain, causing the production to halt. [3, 53, 56]

Efficiency and purity of H_2

As previously stated, the cell voltage is inversely related to the overall efficiency of the system; the higher the cell voltage, the lower the efficiency. Furthermore, the cell voltage determines the current density, which directly translates into the rate of hydrogen production per unit of the electrode active area. This is the area of the electrode in contact with the electrolyte. A higher voltage gives a higher production volume, but at the expense of a lower efficiency. This means there is a trade-off between cell voltage and efficiency. Table 2.3 presents values for energy efficiency (%) and electrical efficiency (KWh/kgH_2). By comparing the energy consumption of the electrolyzers, ranging from 50-93 KWh/kgH_2 to the energy content of H_2, valued at 33 KWh/kgH_2, it becomes clear that the electrolyzers consume more energy at the production end than what becomes available at the product-end. This is, as previously mentioned, a result of the non-ideal process with several irreversible losses during production. The efficiency in the overall systems are typically in the range of 50-68% for both electrolyzer technologies. [58]

Characteristics	Alkaline	PEM
Efficiency (%)	50-68	50-68
Efficiency (KWh/kgH_2)	50-78	50-83
H_2 purity	99.9-99.9998%	99.9-99.9999%

Table 2.3: Performance of Alkaline- and PEM water electrolytic cells [3, 8, 56].

Gas purity of the H_2 coming out of the electrolyzers is another factor that needs consideration. For end-use applications in need of ultra pure hydrogen, the level of purity becomes an important parameter.

Dynamic operation and load factor

The performance and durability of the electrolyzers are presented in Table 2.3. As previously mentioned, the PEM has some flexibility-advantages compared to the AWE. Amongst these are the fast cold start. A cold start-up is defined as start-up from ambient temperature , and PEM electrolyzers can reach cold start-up in less than 5 minutes, and completely shut down within a few seconds[61]. The load range allows for the PEMWE to operate in a stand-by mode which requires a minimal electrical input when the production is shut down, and also an ability to operate at an overload of 160%. The expected lifetime of the stacks are normally shorter than that of the entire system, meaning that the stacks must be replaced a minimum of 1 time during the expected lifetime of the overall system. The stacks are included in the the overall system alongside the balance of plant (BoP), which contains various equipment needed to operate the water electrolysis unit at nominal temperature and pressure, ensuring the purity of the product gas as well as controlling the level of humidity. [3, 56]

Characteristics	Alkaline	PEM
Load range	15-100% nom. load	0 - 160% nom. load
Start-up (warm/cold)	1 minute/10 minutes	1 second/5 minutes
Shutdown	1-10 minutes	Seconds
Expected lifetime (stack)	60 000 hours	45 000 hours
Expected lifetime (system)	20 years	20 years

Table 2.4: Difference in characteristics between PEM and alkaline electrolyzers [3, 8, 56].

One of the major drawbacks of the PEMWE is its high price compared to the AWE, typically around 20-50% higher [8]. CAPEX represents system costs, which includes the electrolyzers, power electronics, gas conditioning and balance of plant, and is an important aspect when deciding which electrolyzer technology to select. Each technology has its own challenges, from critical materials to performance, durability and maturity; there is no clear winner across all applications. This leads to room for improvement, innovation and competition in the industry. [3, 54]

2.6.4 Load Factor

Understanding the concept of load/capacity factor is important when analyzing an energy producing/consuming installation. The load factor characterizes the conversion technology and is used in a number of technologies including hydrogen produced from water electrolysis and power generation from wind-energy. The load factor describes the ratio between the actual generated energy over a given period of time, divided by the maximum theoretical energy generation during the same period, typically evaluated on an annual basis. Put in other words; its a measurement of a power plant's actual generation compared to the maximum amount it could generate over a certain period of time without any interruptions [62]. This becomes increasingly important when dealing with renewable sources of energy where the there are fluctuations in the available energy (wind, hydro, solar etc). [62, 63]

For example, a wind farm with an installed capacity of 500MW will in theory be able to produce 4,380TWh worth of energy if its run at full capacity over the course of one year (500MW × 8760 hours/year). In reality, however, this is not the case. The average load factor for the Norwegian wind farms was calculated to 37.4% in 2020, meaning that the wind farms were only able to operate at full capacity for 37.4% of the year, giving an energy output of 1,638TWh [64]. The same method can be applied to the electrolyzers to get an understanding of their operational numbers. This is crucial in terms of being able to dimension the electrolyzer plant correctly, where the electrolyzer utilization is a key parameter in the case of power-to-gas applications, as will be discussed later on. [4, 65]

2.7 Hydrogen Storage

As shown and explained by Figure 2.8 in chapter 2.4, the energy density of the hydrogen must be increased in order for it to be of any practical use. To increase the density, work must be applied to either compress the gas, reduce the temperature below the critical point, or by chemically bonding hydrogen with another material [66]. The storage process are in many cases considered to be the bottleneck for the hydrogen production industry [67]. There are various hydrogen storage technologies available in today's market, where the two leading technologies are compressed and liquid hydrogen. Other methods of storage include ammonia (NH_3), liquid organic carrier and metal hydrids. Storage in metal hydrids will not be included, as the technology needs further research and development in order to be a considered a viable option. The common denominator for every method of hydrogen storage, is a substantial expenditure of energy in the storage process. This is of concern in terms of the overall efficiency of the hydrogen as an energy carrier as well as a potential economical barrier. [68]

2.7.1 Compressed Hydrogen

The most common and widely used method for storing hydrogen today, is by compression. This is typically done with standard, piston-type mechanical compressors [66]. By using several compressors in a step-wise manner, it is possible to get the compression as close to ideal and isotherm as possible to achieve higher efficiency, thus reducing the amount of work required for compression. The pressure of compressed hydrogen at ambient temperature ranges between 35-70 bar, where 70 bar is considered to be the top performing technology for compressed gaseous hydrogen, or CGH_2 [69]. At these levels of pressure, the CGH_2 is able to meet the market requirements in terms of energy density. [70]. CGH_2 is the most mature technology for storing hydrogen, and have the advantage of a simple treatment process, highly applicable and low in cost. However, the biggest weakness of CGH2 is its low volumetric density, which makes CGH_2 less popular in practise. [71]

When dealing with pressurized hydrogen, the abilities and design of the storage vessels are highly important. There are several ways of storing the CGH_2. For large grid-based production sites, using old salt mines and underground caverns offer a cheap and reliable solution. Another option is to use cylindrical storage units. These storage tanks can be modified in terms of volume, weight and strength (ability to withhold high pressure) to meet the market/manufacture demands. There are four different types of pressure vessels available in today's marked. Each one are made up of different materials which determine the individual vessels characteristics [72]. The storage vessels ranges from low cost, metallic tanks, to expensive fully composite, carbon fiber, polymer vessels [70].

The compression of hydrogen requires work, and it is useful to compare this work to the specific energy content of hydrogen, 33 KWh/kg. In this context, around 10% of the total energy available in the hydrogen is spent on compression, which is an irreversible loss [44]. The compression increases the density by a factor of around 200. In addition to the energy lost by compression, another concerning aspect is the so called hydrogen embrittlement, which is a phenomenon where hydrogen dissolves in the metal of the storage unit and causes deterioration in the form of corrosion, cracks and a reduced load bearing capability in the units [73].

2.7.2 Liquid Hydrogen

The other storage method considered to be well matured and commercially available is storage by liquefaction. To obtain hydrogen in its liquid form (LH_2), cooling is required. Liquefaction usually occurs at the critical temperature of 20K (-253 degrees Celsius) at 1 atm pressure [44]. Operating at such low temperatures is energy consuming. The liquefaction process has an energy requirement of around 10-15 KWh/kg, which is equivalent to about 40% of the energy content stored in the produced hydrogen [72]. This is a substantial amount compared to that of the CGH_2 at around 10%. The main advantage of liquid hydrogen is the high energy density, about 1.6 times higher than the CGH_2 [74].

Liquefaction is done through a multi-stage process that uses a series of refrigerants (often nitrogen) and several compression/expansion loops to convert the gaseous hydrogen to a liquid phase [75]. The simplest liquefaction process is the Linde cycle, also known as Joule-Thompson cycle. In this process, the gas is compressed at ambient pressure, then cooled in a heat exchanger, before it is passed through a throttle valve where an isenthalpic expansion results in the production of some liquid. The liquid is removed, before the process repeats until the conversion is complete [76].

The storage of liquid hydrogen at temperatures around 20K is challenging, and is highly demanding in terms of the technology and materials used for the storage vessels. Due to the large temperature difference between the LH_2 and the ambient outside temperature there are unavoidable thermal heat transfer occurring in the form of convection, conduction and radiation. To minimize the losses, high efficient, double walled metallic containers covered with multiple layers of vacuum insulated are being used in the storage vessels [68]. The heat transfer into the storage unit will inevitably cause the liquid hydrogen to heat up and evaporate in whats known as the "boil-off", contributing to losses of between 0.3% and 3% per day as a result of hydrogen evaporation [68, 71]. The advantage of liquefaction vs compression can be seen in Figure 2.12, where the density is differences becomes clear in terms of storage volume required. As a rule of thumb, the compressed hydrogen requires a 4 times larger storage area than liquid hydrogen [77].

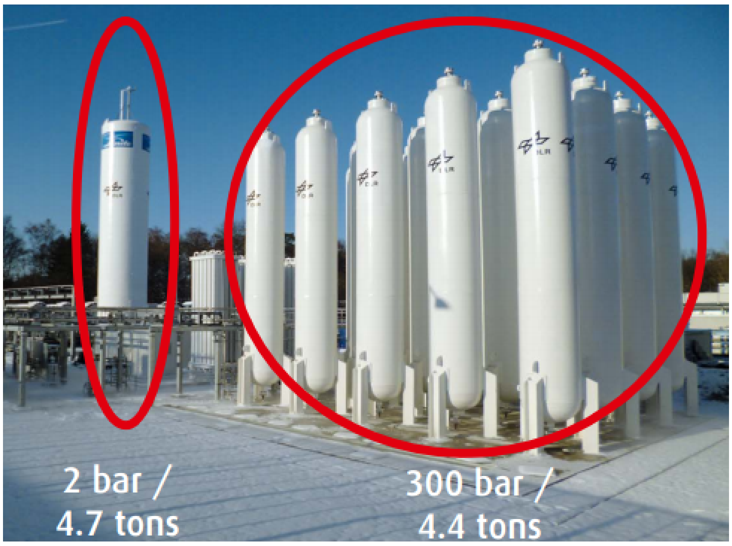


Figure 2.12: Illustration of Liquid and compressed hydrogen storage tanks [77].

2.7.3 Liquid Organic Hydrogen Carrier

Another promising technology for storing hydrogen is by utilizing a liquid organic carrier (LOHC). The idea is to load and unload the organic compound with hydrogen in a chemically binding and cyclic procedure. The loading process, also known as hydrogenation takes place at the hydrogen production cite. This exothermic process is normally done at elevated pressures and temperatures, usually between 10-50 bar and 373 to 523K, depending on the compound that is being utilized. The endothermic unloading of hydrogen; the dehydrogenation, is typically done at ambient pressures and elevated temperatures, typically in the range of 5 to 10 bar and 423 to 673 K [78, 79]. The fact that this is a cyclic process, means that once the liquid carrier has been dehydrogenized, it can be recycled and returned to the spot of hydrogenation for reuse without having been consumed itself [43].

There are several options in terms of the LOHC, and some of the most promising carriers are toluene, N-ethylcarbazole, dibenzyltoluene as well as several other compounds [79, 80]. The carriers possess many similar traits to the ones found in well known fossil fuel energy sources, such as diesel and gasoline. Some of these include a high energy density, the ability to be easily stored under ambient conditions without any substantial leakage or boil-off losses [79]. Normally these LOHC's have a capacity of storing 4-7 wt% of hydrogen [69]. The fact that the LOHC have several physical and chemical similarities with fossil fuels such as diesel, means that the already existing infrastructure can be utilized when distributing and handling the LOHC, leading to a potentially less expensive and simpler introduction of the technology [43]. The main challenge for the LOHC is in the extraction of the stored hydrogen; the dehydrogenation. This endothermic process need to be connected to an external heat source in order for the unloading to occur. Additionally it is a rather slow process, taking up to 4 hours before the hydrogen can be extracted if the initial conditions are ambient [81, 82].

2.7.4 Ammonia

Using ammonia (NH_3) as a liquid carrier for hydrogen storage is another interesting solution. Ammonia is in gaseous state at ambient pressure and temperature, but can be liquefied at 10 bar and room temperature, or by cooling to 240 K (-33 °C) at atmospheric pressure (1 bar). This process is far less energy demanding than liquefying pure hydrogen [83], which needs to be cooled down to 20 K as previously mentioned. Ammonia is hydrogen-dense with about 17 wt% of hydrogen. This makes it an excellent hydrogen carrier, and in its liquid form it is even more energy dense than liquid hydrogen itself, with a volumetric hydrogen density about 45% higher than its counterpart. [84, 85]

There are several methods of utilizing green hydrogen as a supplement to ammonia production. The most famous and widely used method is based on the Haber-Bosch principle. Gaseous H_2 is combined with pure nitrogen (N_2), which is extracted from the surrounding air (which naturally contains around 78% N_2), in a cryogenic process to form ammonia [84]. For the reaction to occur, a temperature above 673 K (400°C) and pressures exceeding 200 bar is required. Such extreme operational conditions lead to the high costs of converting of H_2 to ammonia [86]

Many new and promising technologies for production of ammonia are on the rise, and amongst these are the electroreduction of N_2 to NH_3). The electroreduction utilizes many of the same principles that are found in water electrolysis, such as water splitting at the anode into O_2, protons and electrons. The protons flow through an ion-conducting membrane to the cathode.

At the cathode is where electroreduction process differs from that of the electrolytic cell. N_2 are fed to the cathodic department before being split by use of a catalyst. The nitrogen then reacts with the proton and electron to form gaseous ammonia. The efficiencies can reach levels up to 70%, depending on the electrolyte of choice. There is however a dilemma in terms of efficiency vs time consumption during production, which has proven to be the main challenge for this technology. [84]

How to efficiently make use of the end product; liquid ammonia, is another challenge. Today most of the ammonia production is used for fertilization. There is also the possibility to burn ammonia directly for energy, or extract the stored hydrogen by "cracking" (at elevated temperatures of above 400°C) the ammonia, much similar to the dehydrogenation of LOHC. The only bi-product from combustion of ammonia is the non-polluting N_2 [85]. The use of ammonia as a direct fuel has been gathering much attention in the past few years, particularly in the long distance shipping industry. [83]

2.8 Hydrogen Delivery

In order for the hydrogen to be able to reach its end-use destination, it must be transported. There are a several viable transportation options on the market, with the method of choice dependent on the state of the hydrogen being delivered, as well as the quantity. Some of the most interesting alternatives are transportation via pipeline, trucks or by shipment, where the two latter are the leading options in today's market. Distribution is one of the key elements to a successful implementation of the hydrogen economy. To have a viable and functioning hydrogen infrastructure, it is important to be able to transport hydrogen from the place of production to the point of end-use. The various methods of delivery must therefore be taken into account and be evaluated as part of the hydrogen production chain. [87]

How hydrogen is stored and utilized at the point of delivery, depends on its end-use application. For hydrogen used in portable or stationary applications, it can be delivered by truck to a storage facility, or in cylinders (much like the ones used for storage of propane for gas grills) or in cartridges that would be similar to how batteries are stored. Hydrogen used in FCEV, is dispensed in the same manner as gasoline and diesel by the use of filling stations. The refueling process is the same as for gasoline and diesel, clocking in at around 3-5 minutes. For a typical refueling station with a demand of 1500 kg/d, hydrogen would have to be supplied every three days [87, 88].

Cryogenic liquid trucks

Transportation by road is commonly applied in the hydrogen industry today. Specially designed cryogenic tankers are used for delivery of liquid hydrogen, and are able to transport around 4 tonnes of H_2, about ten times more than the capacity of the equivalent gaseous hydrogen trailer, which is limited by height and weight restrictions due to its lower volumetric density [89]. The liquid hydrogen is transported in specialized double-walled insulated tanks to prevent boil off, based on the same principles as the on-site storage tanks used at the production facility [76]. The tanks can be distributed within a 1000 km radius, a feasible range for the majority of today's production facilities [75]. The Norwegian based company, Linde, delivers liquid hydrogen tanker trucks with a capacity of 4000 kg. The length of the truck is 13.7 m, and these tankers are available in today's market [77].

Carrier ships

Another highly promising way of delivering hydrogen is shipment by sea. Previously, this has only been done using tube skids or high efficiency liquid storage containers, similar to the one utilized for shipment on the road. However, the latest innovations have made transportation possible via specially designed liquid hydrogen tanker ships. The tanker ships allow for large volumes of LH_2 to be shipped over vast distances, thus bridging the gap between point of production and application. [90]

On December 24.2020, Kawasaki Heavy Industries announced its completion of a 10 000 m^3 spherical liquid hydrogen tanker ship, as shown in 2.13a. With a capacity of nearly 710 tonnes of LH_2, it is one of the world's largest tanker ships of its kind. The capacity is large enough to fill up 142 000 fuel cell vehicles (Light-duty FCV with 4–10 kg of hydrogen on-board have a driving range of more than 450 km) [91]. The specially designed on-board storage tanks features a double-shell vacuum-insulated structure, comprised of inner and outer shells with a vacuum-sealed layer in between, to prevent thermal conduction from the outside air as well as convective heat transfer. The tanks have a spherical design to limit the surface-to-volume in order to reduce the boil off losses from heating of the LH_2. [92]. The ship is built to transport LH_2 from Australia to Japan, and Kawasaki aims to add an additional 79 hydrogen carrier ships by 2050 [93]. In the future, Kawasaki is aiming to develop a LH_2 ship with a capacity of around 160,000 m3, based on cylindrical storage units as shown in Figure 2.13b [94].

(a) 2020 carrier.

(b) Future carrier.

Figure 2.13: Illustration of carrier ships of today and the future [94].

Liquid hydrogen pipeline

Transportation by pipeline has up until now been confined to gaseous hydrogen, where reuse of previously existing natural gas pipelines have been applied in several areas of the US, Canada and Europe. The pipelines existing today range anywhere from 18 to 1500 km[89], and are efficient when handling large volumes. Recent research is showing promising signs regarding the implementation of liquid hydrogen transportation via pipeline as well. In 2017, the worlds first fully buried cryogenic pipeline became operative, initially set out to load Ethane and Liquid Natural Gas (LNG), but also capable of delivering LH_2 and ammonia. [95, 96]

The new generation of cryogenic pipelines are referred to as Pipe-in-Pipe (PiP), and are based around a nickel alloy inner pipe, which minimizes the pressure levels needed within the pipe, as well as giving an extremely high thermal insulation, thus reducing boil off losses during transportation and at the same time reducing CAPEX and OPEX. The pipelines can be buried on land as well as placed sub-sea. This makes it a promising solution for delivery of future hydrogen production facilities based on off-shore wind farms. [95, 96]

2.9 Economics

Profitability is vital to any project and its ability to attract investors. There are multiple ways of gauging an investment, depending onthe nature of the project. This section will present key equations regarding the economical analysis of a large scale electrolyzer plant.

Levelized cost of energy - LCOE

In investments regarding energy production, Levelized Cost of Energy is a way of weighing the costs against the profits. The resulting value, the LCOE, determines minimum selling price of each unit of energy, in order to break even. Calculating the LCOE can be done for a all energy carriers, and allows for comparison between them. LCOE calculations are done with the long-term in mind. In order to estimate the LCOE, lifetime expenses needs to be taken into account. The following equation determines these costs.

$$\text{Lifetime Costs} = \text{CAPEX} + \sum_{k=1}^{n} \frac{OPEX}{(1+r)^k} \tag{2.10}$$

n = lifetime
r = discount rate

All investment costs are covered in CAPEX, which are to be paid up front. Costs related to operating and maintaining the project, the OPEX, are affected by the time value of money which is included in the discount rate. The discount rate also includes risk and inflation. The factor n decides the lifetime of the project. When the lifetime cost is know, the LCOE can be calculated using the following equation.

$$\text{LCOE} = \frac{\text{sum of lifetime costs}}{\text{sum of lifetime energy production}} = \frac{\text{TLC}}{\sum_{k=0}^{n} \frac{E}{(1+r)^k}} \tag{2.11}$$

n = lifetime of project
r = discount rate
E = Energy

Production of any future energy, E, is affected by the discount rate, lowering its total value. The resulting number determines the minimum price each unit of energy needs to be sold at. The LCOE is the break even price. If the energy is sold at a higher price, the investment will be profitable. [18, 97]

Net present value - NVP

The net present value is a measure of the present value of future cash flows. NPV is calculated using the following equation 2.12.

$$\text{NPV} = \sum_{k=1}^{n} \frac{R_t}{(1+r)^k} \tag{2.12}$$

n = lifetime
r = discount rate
R_t = cash flow over a given period

Future cash flow is today's value of future income and expenses. This is calculated by summing up the cash flows, R_t, of every period, k. The lifetime of the project limits the calculations to n years in the future. When calculating the NPV, the discount rate, r, is taken into account. Inflation, and the estimated risk of the investment is therefore accounted for. The resulting value is given in the currency in which it is was calculated. A positive NPV means that the investment is profitable, as the time value of money is taken into account. As the NPV relies on assumptions on the future of cash flows, it is accompanied by inherent uncertainty. However, this uncertainty is addressed in the discount rate of the project, mitigating the possible discrepancies. [98, 99]

Discounted Payback Period

Discounted payback period is defined as the time it takes to pay off the capital expenses, i.e the investment. Discounted payback period is more accurate than payback period, as the time value of money is taken into account. All future cash flows are discounted, by a fixed discount rate. This reduces the present value of both income and operating expenses. The period is often set to months or years, whichever one is most appropriate. [100, 101]

Return on Investment - ROI

ROI is a measure of how much return an investor would receive from an investment. If the cash flow and the capital expenditures are known, ROI can be calculated using the following equation:

$$\begin{aligned}\text{ROI} &= \frac{(\text{current value of investment - cost of investment}) \cdot 100\%}{\text{cost of investment}} \\ \text{ROI} &= \frac{\text{NPV} \cdot 100\%}{\text{CAPEX}}\end{aligned} \tag{2.13}$$

The current value of the investment takes all future cash flow into account. When subtracting CAPEX from the current value, the net present value is reached. The resulting decimal value is multiplied by 100%. The end result is given as a percentage of how much return an investor can expect to regain from the initial investment. The investment is profitable for every positive value, and vice versa. ROI can be used as a way of comparing different investment opportunities. Having a percentage as the output simplifies these comparisons. [102, 103]

3 Methodology

This chapter will present the methodology applied during the writing of this thesis. Every piece of relevant information is presented in the following subsections. At first, the structure and scope of the thesis will be briefly explained, before data material, assumptions and calculations made along the way will be described.

3.1 The Basics

The purpose of the thesis is to perform techno-economical analysis of wind powered hydrogen production in Norway. The system is based on a stand-alone scenario, where the only power available is the one generated from the wind-energy. This means there are no grid connection or external battery is included in the system. In order to understand whether or not such a project would be feasible, both the technical and economical aspects must be analyzed. The easiest way of doing such an analysis is to break down the entire system and perform a step-wise analysis of each component individually, before putting the pieces back together to complete the system analysis. This structural approach is illustrated by Figure 3.1.

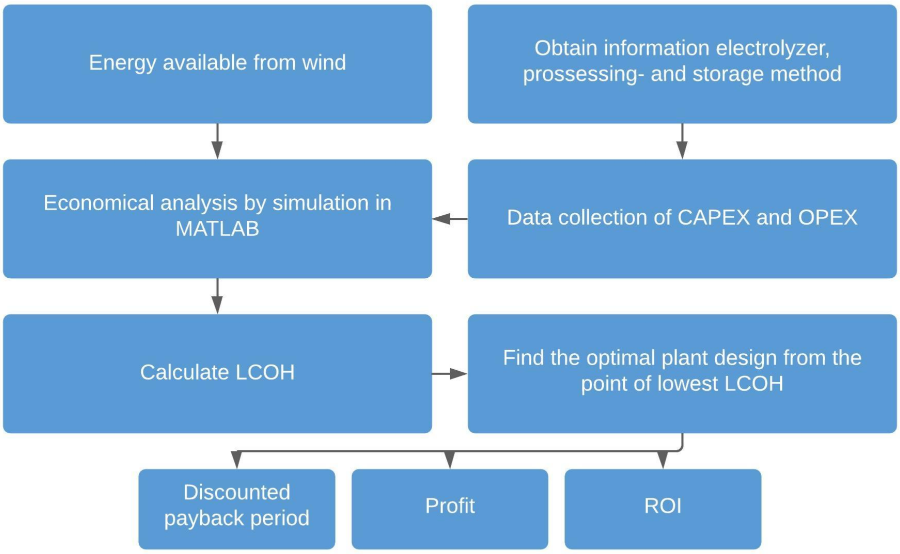


Figure 3.1: Schematic overview of the plant specifications

Data collection and calculation

The collection of the data used for calculations have been gathered from various scientific articles. The articles have been found using Google Scholar, Science Direct and NTNU's online database; NTNU Open. Another highly useful tool has been to utilize the bibliography of the articles themselves. This has led to several valuable sources. The data regarding the available energy from wind were found from NVE's public website, which provides publicly available wind production data for Norwegian wind farms [28]. One of the main challenges in any thesis is to make sure the sources are reliable, accurate and up to date. Finding relevant data for hydrogen production have proven to be challenging, seeing as this is a rapidly growing industry with technical and economical advances continually being made. Only the most recent research has been included, to make sure this thesis is as up to date as possible for a precise representation of the current market.

The calculation and processing of the relevant data has been performed using Microsoft Excel and MATLAB. Excel provides great accessibility and structure when working with larger spreadsheets, which has proven valuable during this period. The cost calculations of the hydrogen production chain has been done in Excel, whereas the economical analysis have been performed in MATLAB.

Assumptions

In order to complete several of the calculations, certain assumptions had to be made. This was done to complete the data-set in order to perform all necessary all the calculations. When evaluating an entire system, every component must be adapted to fit each other for an optimized production capacity to cost ratio. Many of the values found from sources were not given in the right magnitude and therefore had to be modified. This was done by using linear regression or interpolation. Exactly where these methods were applied, and the reasoning behind it will be described in the following subsections.

3.2 Power Available from Wind Energy

Hydrogen production relies on a steady supply of energy. When simulating a green hydrogen plant, having a realistic energy supply is imperative. For the purpose of this thesis, it was decided that Roan wind park was a suitable model for the variable energy input. Roan is a modern wind farm, with a large installed capacity. Using Roan's production curves, available wind energy could be scaled up to meet the requirements of the thesis.

Production data was gathered from NVE's wind power database. NVE releases production figures from each Norwegian wind farm on a yearly basis. These figures were imported to MATLAB, for use in the simulations. This thesis examines large scale hydrogen production, hence the available energy was scaled up to meet the demands of production at this scale. It was decided that 1, 3, and 5 TWh would be suitable values to analyze, considering the size of present wind farms, and future outlooks. When scaling the total production of the wind farm up to 1, 3, and 5 TWh, it was assumed that this would not affect the cost of electricity. The location was also assumed to be able to contain the necessary increase in wind turbines, without affecting production.

It was decided that using only one wind farm as the basis for the simulations would be the most realistic scenario. Using multiple wind farms would even out natural fluctuations of wind production. On a monthly basis, this would not pose an issue, however, on a daily basis it would be of concern. On any given day, wind speeds may vary in different locations, thereby evening out production, and inhibiting the purpose of the analysis.

3.3 Electrolyzer Selection

There are several electrolyzers from a number of different producers available today's market. Some of the biggest names include Cummins, ThyssenKrupp, ITM Power and NEL. These are companies that deliver products for small scale hydrogen production as well as large scale, both PEM and Alkaline electrolyzers. The electrolyzers delivered from the Norwegian company NEL are the ones being analyzed in this thesis. The electrolyzer specifications is shown in Table 3.1. The modules are made up of several stacks - all operating under the same BoP components. A1000 and A3880 are the alkaline models delivered by NEL, whereas M400 and M4000 are the available PEMWE models. By combining different modules, the desired installed capacity of the electrolyzer facility can be obtained.

Technology	Modell	Module size [MW]	Stack size [MW]	Number of stacks
Alkaline	A1000	4.5	2.25	2
Alkaline	A3880	18	2.25	8
PEM	M400	2	2	1
PEM	M4000	20	2	10

Table 3.1: Electrolyzers from NEL [104].

Modell	Module size [MW]	Max prod. [kgH_2/day]	Water cons. [l/kgH_2]	Energy cons. [kWh/kgH_2]	Output pressure [bar]
A1000	4.5	2049	10	47	30
A3880	18	8195	10	47	30
M400	2	872	10	51.5	30
M4000	20	8448	10	51.5	30

Table 3.2: Electrolyzer production data from NEL [104].

The production data of the electrolyzers were obtained directly from brochures provided by NEL [104]. The values found are used for calculations throughout the thesis, and are shown in Figure 3.2. The max production value is given for when the electrolyzer is operating at a full load factor. Water consumption is given with the assumption of max efficiency where all water consumed is utilized during operation. The energy consumption is an approximation of the data given by NEL's brochures. The value is an initial value given for the electrolyzers first year of operation, and will increase over time as the electrolyzer efficiency suffers from degradation. As a simplification for further analysis, the energy consumption value will stay constant throughout the lifetime of the hydrogen production plant. The output pressure for hydrogen produced is the same for all the electrolyzers; given at 30 bar.

3.4 Hydrogen Production

The wind production data were fed into MATLAB, and scaled up accordingly. Using a combination of loops, the electrolyzer plant was scaled up by one module at a time, until the capacity of electrolyzers equaled the maximal output from the wind farm. Each iteration ran for the full wind production period, i.e. one year. The max theoretical hydrogen production capacity can be seen in Table 3.2, a number that represents production from the electrolyzers if run under optimal conditions all day. These loops made production data available for every configuration of available wind energy, electrolyzer module, and installed electrolyzer capacity.

The alkaline electrolyzers, A1000 and A3880, require a two hour ramp up time. A control was set in place, in such a way as to review how many, if any, modules would have to undergo a cold start on a particular day. Hydrogen production from these modules were reduced by 8.33%, accounting for the ramp up time. The PEM electrolyzers, M400 and M4000, do not experience losses at cold starts, and were excluded from this check. The resulting production numbers were then available to be used in further analysis. In addition to supplying a reliable estimate of the hydrogen production numbers, the numbers were needed to accurately perform the economical analysis. Storage capacity is directly linked with hydrogen production, and require production data in order to be calculated. For use in the economical analysis, the future value of hydrogen was reduced according to the discount factor, explained in detail in section 3.6.

3.5 Cost Analysis

The main objective in the following subsections is to get a better understanding of the individual components contribution to the overall cost of the hydrogen production facility. By finding the cost of every component involved; from the very beginning of the hydrogen production process all the way to the hydrogen delivery section, it is easier to get an understanding of the hydrogen production chain in its entirety. This included the electrolyzer system, the process of liquefaction and lastly the storage. Both CAPEX and OPEX was included for a complete analysis. All capital expenditures, as well as stack replacements, were increased by 25% to account for VAT[105].

Lifetime

Setting a finite time for the length of operation is necessary in order to calculate the operation and maintenance costs throughout the lifetime of the system. These costs are found as annual expenses and will keep on running until the system eventually shuts down. The different components in the hydrogen production chain has various lifetime expectancies, but it was decided to use the electrolyzer lifetime as an estimated value for the entire plant. Values ranging from 15-20 years were found from various literature [3, 15, 106], and it was decided to use a 20 year expected lifetime for the operation.

Key figures

The different costs are generally given per unit of energy (kWh), power (kW), production rates (kg/h or Nm^3/h) or capacity (kg or ton). These units are modified and converted for an easier comparison between the different components. Another important aspect is the exchange rates for conversion between Euro (€), Dollar ($) and NOK. The values are found from Norges Bank and are presented in Figure 3.2 and 3.3. Because of the fluctuating nature of the exchange rates, a standard value of €= 10,16 NOK and $ = 8.59 NOK was chosen and used throughout the thesis.

Figure 3.2: Exchange rates €/NOK [107].

Figure 3.3: Exchange rates $/NOK [108].

Components involved

The production chain can be broken down into the individual components shown in the bullet list below. The list presents the different costs involved in the hydrogen production, from planning to delivery of liquid H_2. CAPEX and OPEX for every component will be analyzed and found accordingly.

- Electrolyzer stack and stack replacement
- Balance of plant (Rectifier, transformer, water treatment and gas cleaning)
- Liquefaction, piping and filling equipment
- Storage tanks
- Other costs (Engineering, planning, foundation and building, admin)
- Electricity, battery backup and water costs
- Operational and maintenance costs

3.5.1 Setting the Boundaries

When estimating the cost for various electrolyzers, there are several problems involved. First of all, the individual electrolyzer producers are highly cautious when providing data for their products. Sensitive information that may or may not provide any competitive advantages within the business is kept out of commercial reach. Secondly, the boundaries for what is considered to be part of the system (e.g. stack, BoP) is rather obscure and inconsistent. This makes it difficult to analyze each electrolyzer up against each other, and several assumptions are therefore needed in order to calculate the expenses involved. There are also other important factors such as production volume and electrolyzer capacity, which contributes to variations in the overall cost [3]. These challenges extends to the other components in the production chain as well, both in terms of CAPEX and OPEX.

A solution is to split the costs into two categories; equipment costs and non-equipment costs. The equipment costs contains the electrolyzer system, the liquefaction plant and the storage units, whereas the non-equipment cost (other costs) is found as a percentage of the equipment cost. OPEX is normally found as a percentage of the different CAPEX components, but elements such as electricity, battery backup, water cost and stack replacement is expressed as a function of the hydrogen production volume.

3.5.2 Electrolyzer System and Stack Replacement Cost

The expenses involved in the electrolyzer system is split into CAPEX and OPEX as well as stack replacement costs. The costs are size- and technology dependent. Both the Alkaline and PEM water electrolyzers is evaluated in this section.

Electrolyzer system CAPEX

To set the boundaries for the electrolyzer system costs, it is useful to break the system down into two separate sections of costs - with additional sub-levels. The stack costs and the balance of plant costs makes up the two main sections. These are part of the alkaline as well as the PEM system. The stack is, as mentioned in chapter 2.6, the core of the system where the electrochemical process is taking place. The balance of plant are comprised of several subsystems which enables the stack to function properly at all times. These subsystems differ with each electrolyzer technology, but some key elements are the power supply, water circulation system, hydrogen processing (compression and storage) and cooling.

The components involved in stack and BoP differs between Alkaline and PEM, but the cost distribution is the same, as shown in 3.4 and 3.5. The combination of the stack and BoP makes up the electrolyzer system. It is important to note that relationship between stack cost and BoP cost is not constant, but dependent on the size of the electrolyzer system. For a 1 MW module, the cost distribution is 45/55 as shown in the figures below [3]. For larger modules however, the cost will be shifted toward a stack dominated cost distribution. This comes as a result of more stacks working under the same BoP, which means that a larger system will have a bigger increase in number of stacks compared to the BoP components. As a result of this, the larger modules comes at a cheaper cost than the smaller modules.

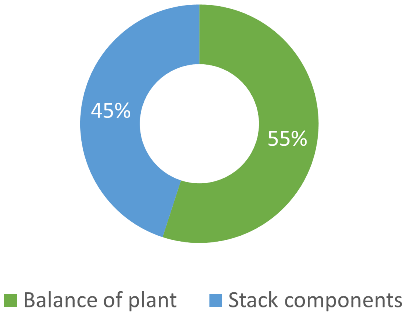


Figure 3.4: Cost breakdown of a 1 MW AWE [3].

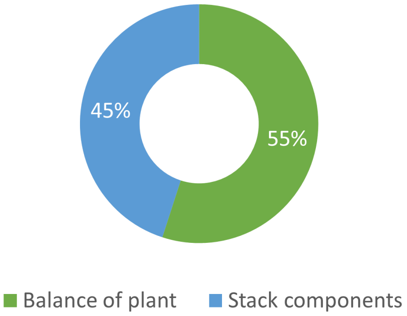


Figure 3.5: Cost breakdown of a 1 MW PEMWE [3].

The variables involved in the cost projection of the electrolyzers is electrolyzer technology (PEM or Alkaline) and the module size. Most of the sources found related to the electrolyzer cost operated with a cost given in €/kWh. These were usually costs given for a general electrolyzer system without any specifications regarding the system size. Sources operating under such general terms were quickly discarded. The CAPEX values for the electrolyzer systems used in this thesis is presented in Table 3.3. These values are projected as a function of the module size, which gives a much more precise cost estimation. The values found from the IRENA, 2020 publication [3], which are based on the projections given by Sayed et al. [109] and Proost [5]. Appendix B is included as a source of comparison to make sure the values chosen are reliable and up to date.

Electrolyzer	Module [MW]	CAPEX [€/kW]
PEM	2	924
PEM	20	512
Alkaline	4.5	664
Alkaline	18	438

Table 3.3: Cost of electrolyzer systems [3].

Electrolyzer system OPEX

The electrolyzer system OPEX includes maintenance, spare parts and replacement of the auxiliary components such as pumps, filters, etc. This excludes electricity, water consumption and stack replacement costs, which will be considered individually in the following sections [110]. The OPEX is given as a percentage of the CAPEX per year. The percentage is determined from the values presented in Appendix C. An OPEX value of 4% is chosen for the purpose of this thesis.

- **OPEX** for PEM and AWE is given as **4% of the electrolyzer CAPEX per year**.

Stack replacement cost

Some of the components in the stack will deteriorate over time. This will affect the performance of the stack, which will suffer from efficiency losses - leading to a higher energy consumption during production. The stack degradation is expressed in number of hours of operation and usually needs replacement when the efficiency drops to below 90% of the nominal value. [110]

The stack replacement cost is a function of the electrolyzer module size, and is presented in Table 3.4. The initial values are found from Table B.3, in Appendix B , and are interpolated to fit the electrolyzer module sizes [110]. The lifetime of the stacks are normally predicted to be anywhere in between 45-80000 hours, depending on the electrolyzer technology [3]. For this thesis, however, a lifetime value of 78750 hours have been utilized for both PEMWE and AWE. The numbers were obtained directly from NEL [104]. These lifetime-values are in the upper range in terms of what is normally given, but is deemed accurate and relevant seeing as NEL's electrolyzers are the ones being analyzed throughout this thesis.

Technology	Module size [MW]	Stack repl. [€/kW]	Lifetime Stack [hours]	Lifetime of module [years]
PEM	2	428	78750	20
PEM	20	341	78750	20
Alkaline	4.5	340	78750	20
Alkaline	18	296	78750	20

Table 3.4: Electrolyzer stack replacement cost [110, 111].

3.5.3 Costs of the Liquid Hydrogen Pathway

The costs involved in the liquid hydrogen pathway are split between the liquefaction process and the storage. The liquefaction process is where the hydrogen is being liquefied, and the storage facility consists of units for storing the liquid hydrogen. The expenses can be divided into CAPEX and OPEX in the same manner as for the electrolyzer system costs. All of which will be presented in this section.

Liquefaction plant CAPEX

Finding the costs involved in the liquefaction process was not a straightforward process. Gathering relevant material were difficult, seeing as the reliable sources rarely dealt with specific costs of liquefaction plants of varying sizes, but rather operated in conceptual terms. There was, however, some concrete data available which made it possible to plot the cost of the liquefaction plant as a function of the plants capacity. The cost of liquefaction was split into CAPEX and OPEX. The majority of the cost will be the capital investments, which constitutes about 63% of the overall costs. At the operating end, the energy costs (power consumption during liquefaction) makes up 33% of the overall costs, whereas the remaining 4% is spent at the operating and maintenance end [89]. In large scale plants the energy costs become more substantial, as the CAPEX will decrease relative to the production capacity as a result of economies of scale [112]. For simplification, the cost of energy related to conversion from hydrogen to liquid hydrogen has been included as part of the CAPEX. This was done to avoid confusion as a result of the inconsistent values of power consumption during production.

Four different cost models was evaluated in order to find the most reliable one, all of which has been plotted and presented in Appendix D. Cost model 1 (ref D.1a) and 2 (ref D.1b) was obtained directly from the source, whereas cost model 3 (ref D.1c) and 4 (ref D.1d) was initially presented as functions of plant capacity, but later plotted for various capacities for an easier visual representation and comparison. The representations shows the investment cost/CAPEX over plant capacity.

The energy required for liquefaction is dependant on the efficiency of the liquefaction plant. The ideal work required for liquefaction of hydrogen is 3.228 kWh/kgLH$_2$, as mentioned in 2.7.2. The most modern hydrogen liquefaction plants today operate withing the range of 8-10 kW/kgLH$_2$, with predictions of future state-of-the-art plants to operate at 6 kW/kgLH$_2$ [113]. The plants considered in this thesis operate with values ranging from 10-15 kW/kgLH$_2$. This variation in energy consumption makes it difficult to perform a precise comparison between the four different models evaluated in this thesis. Another minor issue, or rather source of confusion, was the definition of plant capacity. Some of the sources operated with a unit of measurement being kgLH$_2$/day, that is liquid hydrogen produced per day. Others utilized hydrogen consumed per day, that is kgH_2/day as the definition of plant capacity. Often the two units were being used interchangeably. To set the record straight and avoid any confusion, the definition of liquefaction plant capacity is kgH_2/day.

For the purpose of this thesis, cost model 3 has been chosen. The rational behind this decision is the cost models power consumption of 10 kW/$kgLH_2$ which is on a level similar to todays operating values, as well as the CAPEX being valued somewhat in the middle ground compared to the other models. The cost model is represented as function of plant capacity and is presented in equation 3.1, with cost given i M€. The exponent shows how the liquefaction cost decreases with an increase in plant capacity as a result of economies of scale.

$$y = 7.37x^{0.6667} \tag{3.1}$$

Storage CAPEX

Depending on the source, the cost of liquid hydrogen storage is sometimes included in the overall liquefaction plant cost, but will in this paper be separated to get a better understanding of the individual components in the plant. The costs involved in storing liquid hydrogen are predominantly driven by the installation costs, with the most prominent contributor being the material cost of the storage tank. Additional costs include interconnecting pipes, valves, and pumps needed for the storage process to function optimally.

The liquid hydrogen is stored in cryogenic tanks at the hydrogen production facility. The capacity of the storage tanks is determined by the production capacity of the liquid hydrogen plant and the station storage demand. This is the demanded capacity expressed in days of production, and is set to 10 days [90, 114] . In other words, the storage capacity must be able to store 10 days worth of hydrogen production at max production rate. The boil off losses is set to 0.03% which is deemed reasonable for a large scale hydrogen storage facility [90].

Data for determining the cost of storing liquid hydrogen was obtained from Reuß et al. [114]. The cost is calculated by using a scaling function which operates with a rising throughput, often used for calculations involving chemical plants. The function is presented in Appendix E, equation 3.2, and is based on a number of initial, set values in combination with a variable capacity, resulting in an estimated investment cost (CAPEX). By inserting a series of values for the storage capacity ($kgLH_2$), as shown in Table E.1, cost function 3.2 was obtained. The scaling factor for storage was set to be 0.95 [112, 114], which is a typical value for storage units, seeing as there are little to no economy of scale involved in this particular piece of the hydrogen production chain. A scale up would require a near linear increase in materials needed, and therefore also a proportional increase in cost.

$$y = 0.0149x^{0.95} \tag{3.2}$$

OPEX for liquefaction and storage

The OPEX is given as a percentage of the CAPEX per year, similarly to how the OPEX was found for the electrolyzer system. The OPEX for the liquefaction plant consist of operation & maintenance cost and is set to 4% of the CAPEX per year [112]. The OPEX for storage is also given as representation of the O&M expenses, and is set to be 4% of the CAPEX per year in accordance to data collected from various sources [75, 90, 112, 114].

- **OPEX** for liquefaction is given as **4% of the liquefaction CAPEX per year**.
- **OPEX** for storage is given as **4% of the storage CAPEX per year**.

3.5.4 Hydrogen Production Facility Costs

The previous sub-sections dealt with the costs of the major equipment involved in the hydrogen production facility (electrolyzers, liquefaction plant and storage). This sub-section, however, will present the additional costs needed in order to complete the project. Following the approach conducted in the previous sections, these costs are also separated into CAPEX and OPEX. The expenses are referred to as "other costs" or "non-equipment costs", and represents costs linked with construction work, engineering, planning, legal fees, operation, piping, interconnection etc [110]. All of which are crucial in terms of achieving a fully functioning hydrogen production facility. CAPEX for these cost is found as a percentage of equipment costs as shown in equation 3.3. The percentage is dependent on the installed capacity of the hydrogen production facility, $P_{Project}$, and decreases with scale as shown in Table 3.5.

$$\text{Other costs} = 10\% * \left(\frac{2.5MW}{P_{Project}}\right) + 35\% \tag{3.3}$$

Project Scale [MW]	**Other costs [% of equipment costs]**
1	60
5	40
20	36
50	36
100	35

Table 3.5: Other costs scaling [110].

The operational expenditure is given as a percentage of the other costs, or the non-equipment costs, and is set at an estimated value of 4%. These facility-related costs include site management, land rent and taxes, administrative fees and site maintenance.

- **OPEX** for other costs is given as **4% of the other cost CAPEX per year**.

3.5.5 Water and Electricity Costs

Electrolysis require two inputs to produce green hydrogen. Water and green electricity. Both costs proved to be difficult to pinpoint. Water costs depend on the location in which it originates, however they are generally low. In plants of the sizes analyzed in this thesis, water costs are marginal compared the other expenses involved. LCOE is utilized as the main metric of electricity cost. This allows for wider utilization of the results, at the cost of some uncertainty. The uncertainty is a result of difficulties pinpointing an exact value.

Cost of water consumption

Water consumption in NEL's electrolyzers were all set to 10 l/kg. The size of the electrolyzer plants which are simulated in this thesis, require large amounts of water. Access of water is outside the scope of this thesis, and it was assumed that water supply was not an issue. Norway has large reservoirs of water on land, and desalination technology is well established.

In this thesis, the cost of water was set to 0.002 €/l and is not subject to further analysis. Compared to the other components in the plant, the cost of water has a low impact on the end result. Some uncertainty was therefore regarded as acceptable in defining the cost of water.

Cost of electricity

The levelized cost of energy, LCOE, is a figure which deemed itself to be impossible to define correctly. This is a central figure when it comes to a company's competitiveness. Therefore, it is a well guarded secret amongst the energy companies. Finding a realistic LCOE would prove to be a challenge.

In this thesis, a baseline LCOE of 30 €/MWh was set. This is assumed to be a realistic value in which to base the simulations on. In the cost analysis of hydrogen plants, electricity is one of the largest costs. Therefore, the results are heavily dependant on the price of electricity. With the lifetime of the plant being 20 years, estimates of LCOE will include a growing uncertainty. Both the LCOE set in this thesis, and the future cost of energy are subject to uncertainty. Conducting an analysis on different LCOE's are crucial in order to account for this. It was decided that a variance of 10 €/MWh would be sufficient to ensure the quality of the results. This was done in a sensitivity analysis, where electricity costs were set to 20, 30 and 40 €/MWh.

3.6 Economical Analysis

The feasibility of large scale electrolyzer plants generally relies on its profitability. Large amounts of capital investments are necessary to initiate a large scale plant. A thorough economical analysis is therefore required to assess the profitability of the project. This section will present how the key economical figures are calculated.

Plant simulation

The calculations in this thesis were all done with Excel and MATLAB. Utilizing these programs increases the accuracy of the results, and at the same time reduces the workload. The initial data collection was saved in Excel. When all the necessary information was gathered, work began on scripting the analysis in MATLAB. Wind farm production, hydrogen production, CAPEX, OPEX, as well as LCOH and further economical analysis, were all calculated within the script. Having access to data points in every step of the calculations, simplifies the process.

Corrections and adjustments were made underway, benefited by these data points. Once the script was complete, and the results were available, the usefulness of the metrics were decided. Thus a data set of relevant results became available. The full script, with the accompanying explanations is shown in appendix I.

LCOH

The levelized cost of hydrogen, abbreviated LCOH, determines the price at which the hydrogen would be need to be sold for, in order to break even. This figure can also be used to compare different production methods. Firstly, the lifetime cost needs to be calculated. For this, the following equation is used.

$$TLC = CAPEX + \sum_{k=1}^{n} \frac{OPEX}{(1+r)^k} \tag{3.4}$$

n = *lifetime*
r = *discount rate*

Total levelized cost, TLC, is the sum of all capital and operational expenses. The lifetime of the project, n, is set to 20 years. The present value of both expenses and profits from sales, are adjusted according to the discount rate, r. Inflation, risk, and the time value of money are reflected in the discount rate. These equations can be applied to hydrogen as its considered an energy carrier.

$$LCOH = \frac{sum\ of\ lifetime\ costs}{sum\ of\ lifetime\ H_2\ production} = \frac{TLC}{\sum_{k=0}^{n} \frac{E_l}{(1+r)^k}} \tag{3.5}$$

E_l = *Liquid Hydrogen (kg)*

The lifetime production of hydrogen, E_g, must be divided by the same discount factor. Future hydrogen is regarded as future cash flow, thus the present value needs to be determined. The resulting LCOH determined to optimal plant size, and was used in further analysis, as well as discussing the feasibility of production.

Relationship between LCOH, CAPEX, and electricity costs

In order to accurately analyze the present or future feasibility of large scale electrolyzer plants, it is necessary to present viable variations of a selection of costs. It was determined that the CAPEX of the modules and the cost of electricity were likely to fluctuate, and therefore considered as useful factors to analyze further. The cost of electrolyzer modules were reduced step-wise from 0-50%, providing results that simulates future developments in technology and prices. This reduction was applied to the cost of each module, as well as the cost of stack replacement. Throughout the thesis, electricity costs operate at a set, initial value of 30 €/MWh. This value represent the investment and operational costs associated with owning a wind farm, and are based on a number of factors such as location, subsidies, and developments in technology. A variance of 10 €/MWh expands the relevance of the results. The simulations were run for electricity costs between 20, and 40 €/MWh.

Discounted payback period and ROI

LCOH determines the price of hydrogen where any investor would break even in the 20 year lifetime of the plant. In order to profit from the plant, it is necessary to sell the hydrogen at a price-point higher than that of the LCOH. Simulations were performed, where the price of hydrogen was set to vary between 1 and 10 €per kilogram of liquid hydrogen. These calculations provided the means to determine the discounted payback period, and the return on investment (ROI). The discounted payback period is a measure of how many years it will take to pay off the capital expenses, taking the time value of money into account. Return on investment is a measure of how large the profits are, as a percentage of the initial capital investment. This measure also depends on the time value of money.

3.7 Scenario 1 vs Scenario 2

This thesis mainly analyzes the viability of constructing an off-grid electrolysis plant. It is assumed that the wind farm solely supplies energy to the hydrogen plant. As a consequence, any electricity not utilized by the hydrogen plant is lost. Expenses related to energy consumption are static, as they are based on total wind energy production. This is meant to simulate a wind farm which does not have the ability to sell excess energy. Costs of building and maintaining the wind farm are compressed into the cost of electricity, the LCOE. In this thesis, the stand alone system is referred to as scenario 1.

It was deemed necessary to compare the results of scenario 1 to a grid connected solution. This is to be know as scenario 2. This scenario aims to connect the wind farm to the grid, providing results which are more comparable to previously conducted studies. The cost of electricity is directly linked with energy consumption by the electrolyzer plant. In order to effectively compare the different scenarios, the cost of electricity remains the same. The electrolyzer modules, however, will not be connected to the grid, as they are solely supplied by the wind farm.

4 Results

The following chapter will present the costs related to production, liquefaction and storage of hydrogen. Scenario 1, the off-grid scenario, is used as the basis of evaluation. The cost values are analyzed for the entire lifetime of the hydrogen production plant (20 years), and the data will be presented in tables as well as diagrams. There will also be presented an economical analysis that evaluates how the LCOH is affected when a set of variables are changed. These variables include the number of modules installed, electricity price and a price reduction in the electrolyzer CAPEX - all of which will be plotted for a visual representation of the changes.

4.1 Available Energy

Roan wind farm produced a total of 935 GWh in 2020. Energy production varies on a day-to-day basis, with seasonal trends. On days where production exceeds the installed capacity of the electrolyzers, the excess energy is lost. In the upcoming chapter 4.4, further analysis is done in the scenario where this loss is negated. The following results, however, are based around the inclusion of these losses. Figure 4.1 shows the daily and monthly distribution of wind energy production from Roan.

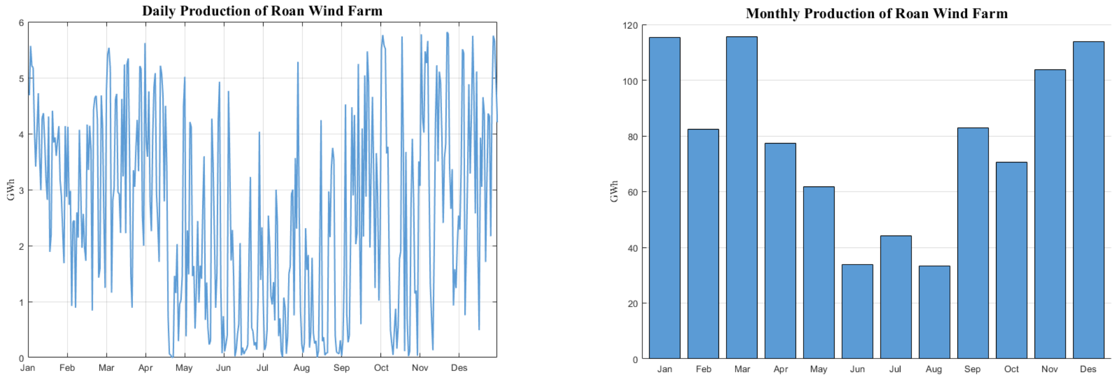


Figure 4.1: Production curves from Roan wind farm.

As this thesis operates with total production values of 1, 3, and 5 TWh, Roan's production needed to be scaled up. The scaling factors are 1.073, 3.219 and 5.365 respectively. It was assumed that the distribution of energy production would not change, i.e the production curves remained after the scale-ups. Table 4.1 presents the result of scaling up the available energy.

Installed capacity [MW]	Estimated production [TWh]	Estimated operational time [%]
274	1	40.2
825	3	40.2
1374	5	40.2

Table 4.1: Productional values from the up-scaled wind farm.

4.2 Costs and Plant Specifications

The cost distribution is evaluated in relation to the energy available at the source, that is 1, 3 and 5 TWh. Both the AWE and PEMWE is analyzed and compared throughout this subsection. The initial conditions in terms of hydrogen plant size and load factor was found from the point of optimized LCOH. This is shown graphically in subsection 4.3.1. From the point of optimal LCOH, the initial conditions was found, thus connecting the energy at hand with the optimal plant design. The plant compositions shown in Table 4.2, and their respective values, forms the basis for the following CAPEX and OPEX calculations. Several modules are added up to obtain the desired plant capacity, which increases with the amount of energy available for exploitation. In other words; the more wind energy available, the larger the electrolyzer plant will have to be in order to fully utilize the resources. The load factor show how much of the installed capacity is being utilized. Load factors in the range of 57-59%, indicates that the electrolyzers operates at rated capacity for a little over half the time.

Energy [TWh]	Electrolyzer model	Module size [MW]	Number of modules	Plant size [MW]	Load factor [%]
1	M4000	20	8	160	58
	A3880	18	9	162	58
3	M4000	20	26	520	58
	A3880	18	29	522	58
5	M4000	20	43	860	59
	A3880	18	50	900	57

Table 4.2: Sizing of the hydrogen production plant.

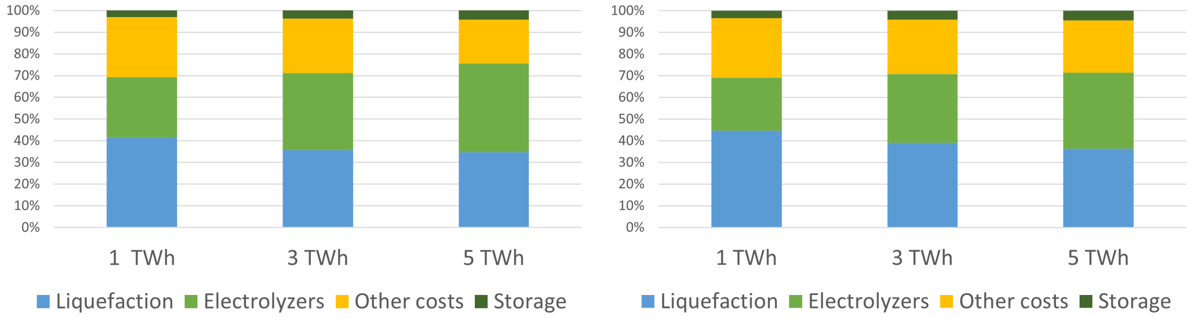
4.2.1 CAPEX

The investment costs constitutes a large amount of the expenses involved in a hydrogen production facility. The total CAPEX have been calculated as explained in the methodology chapter, and is presented in Table 4.3. Each contributing component is presented individually and then summarized to obtain values for the total CAPEX. The data is presented in the same manner as in the previous part; sectioned by the available energy for production and the associated installed electrolyzer capacity, both PEMWE and AWE.

Energy [TWh]	Electrolyzer [Module]	Electro-lyzer [M€]	Lique-faction [M€]	Storage [M€]	Other costs [M€]	Total CAPEX [M€]
1	M4000	102.48	152.90	11.37	101.26	368.01
	A3880	88.70	161.98	12.35	99.72	362.74
3	M4000	333.06	335.49	34.84	236.21	939.60
	A3880	285.80	353.38	37.52	227.16	903.85
5	M4000	550.83	469.19	56.19	274.39	1350.60
	A3880	492.75	508.12	62.95	337.44	1401.26

Table 4.3: CAPEX distribution data.

To get a better understanding of the CAPEX distribution, the components are presented graphically as shown in Figure 4.2, where 4.2a shows the PEM-based hydrogen plant and 4.2b shows the AWE-based plant. In these figures, the CAPEX components are presented as percentages of the overall CAPEX, and the different sizes are plotted side by side to illustrate how the relative value of the various components changes with size. The electrolyzers and the liquefaction makes up the majority of the overall cost, of about 70%, whereas other costs and storage makes up the remaining costs.



(a) PEMWE

(b) AWE

Figure 4.2: CAPEX distribution for 1, 3 and 5 TWh systems.

4.2.2 OPEX

The operational and maintenance expenses, the OPEX, is given by Table 4.4 and 4.5. The values are given as an annual expense in M€/year, and represents the cost of each component in an average year of operation. The stack replacement is not a running, annual cost, seeing as the stacks are not replaced every year. It is rather a bulk expense that comes to play when the electrolyzers need stack replacement. These large costs have been divided into equal shares to represent an annual expense.

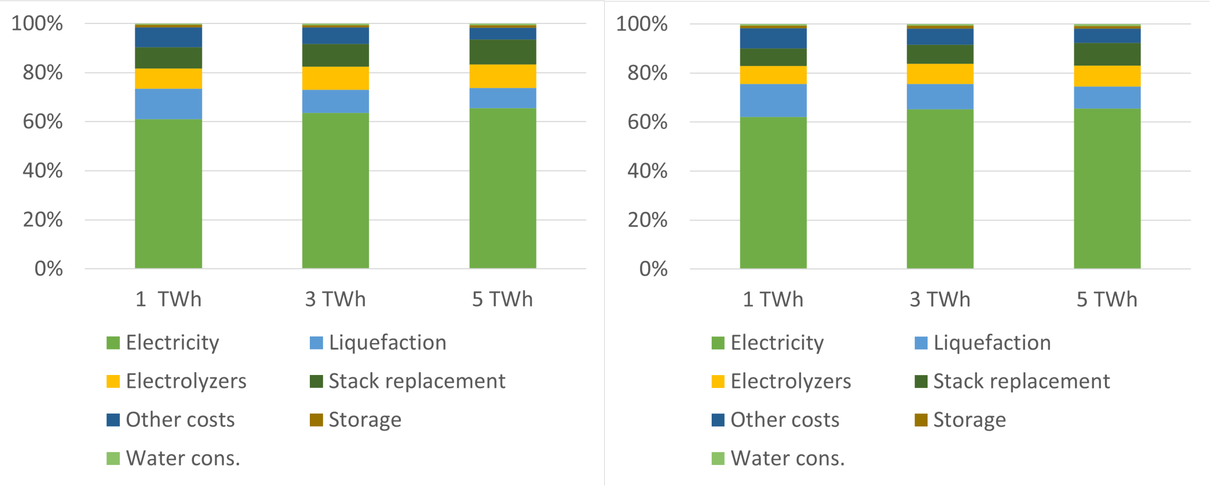
Energy [TWh]	Electrolyzer model	Electrolyzer [M€]	Stack repl. [M€]	Electricity [M€]	Water cost [M€]
1	M4000	2.01	2.07	14.73	0.14
	A3880	1.74	1.71	14.73	0.16
3	M4000	6.54	6.47	44.18	0.46
	A3880	5.61	5.25	44.18	0.49
5	M4000	10.82	11.47	73.64	0.78
	A3880	9.68	10.31	73.64	0.82

Table 4.4: OPEX distribution data part 1.

Energy [TWh]	Electrolyzer model	Liquefaction [M€]	Storage [M€]	Other costs [M€]	Total OPEX [M€]
1	M4000	3.00	0.22	1.99	24.17
	A3880	3.18	0.24	1.96	23.71
3	M4000	6.59	0.68	4.64	69.57
	A3880	6.94	0.74	4.46	67.67
5	M4000	9.21	1.10	5.39	112.40
	A3880	9.98	1.23	6.63	112.29

Table 4.5: OPEX distribution data part 2.

The OPEX components are also shown graphically by Figure 4.3a and 4.3b, where the PEMWE- and AWE based systems are presented respectively. The electricity cost dominates with a value of around 65% of the total OPEX. These are the costs related to the production of hydrogen from water electrolysis.

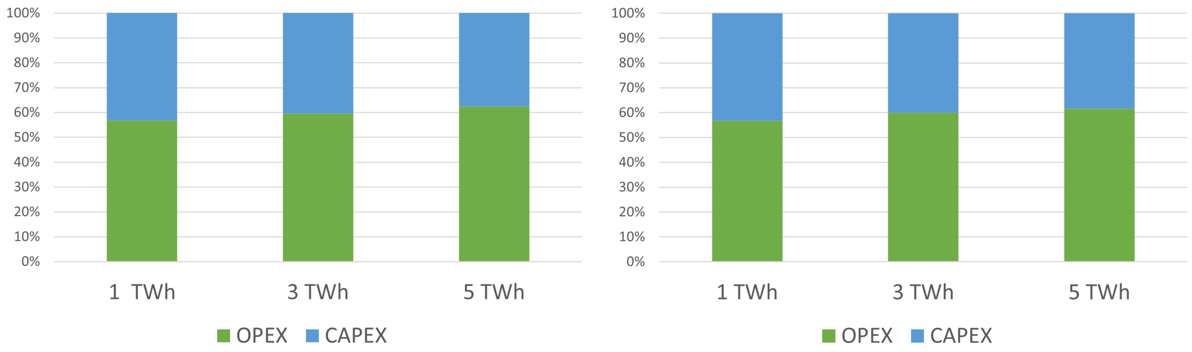


(a) PEMWE (b) AWE

Figure 4.3: OPEX distribution for 1, 3 and 5 TWh systems.

4.2.3 CAPEX vs OPEX

To better understand how the CAPEX and OPEX relates to one another, and how much of an impact they have on the overall cost of the hydrogen production facility, Figure 4.4a and 4.4b are presented. These figures show the CAPEX and OPEX as percentages of the overall cost, and are split into the PEMWE- and AWE based systems. The OPEX is given as a lifetime cost as the sum of each annual OPEX added together over the entire lifetime. A discount rate of 8% has been used for the calculations. The results show that the OPEX accounts for 60% of the overall cost, with the electricity costs being responsible for around 40% of the overall costs.



(a) PEMWE (b) AWE

Figure 4.4: CAPEX vs OPEX distribution for 1, 3 and 5 TWh systems.

4.2.4 Water Consumption, Plant Footprint and Hydrogen Production

Some of the key production values are presented in Figure 4.6. The amount of H_2 and LH_2 is presented for every plant composition as well as the water consumption during electrolysis. Another interesting component has also been included; the plant area. An observation here is that the PEMWE plant occupy a smaller area than the equivalent AWE plant, about 60% smaller.

Energy [TWh]	**Electrolyzer model**	**Plant size [MW]**	**Water cons. [t/year]**	**Plant Area** $[km^2]$	H_2 **prod.** $[tH_2/year]$
1	M4000	160	143 109	0.013	14 247
	A3880	162	156 044	0.021	14 997
3	M4000	520	465 105	0.042	46 433
	A3880	522	502 809	0.068	48 492
5	M4000	860	782 474	0.069	77 850
	A3880	900	851 965	0.117	82 690

Table 4.6: Plant specifications and productional values.

4.3 Sensitivity Analysis

This subsection of the thesis will analyze how different factors change the economical realities of a project of this scale. The following results are based on scenario 1, assuming an off-grid solution. A comparison between scenario 1 and 2 is presented in subsection 4.4.

4.3.1 LCOH

The levelized cost of hydrogen, LCOH, is a central figure when deciding the profitability of a project. The LCOH is the minimal price at which the liquid hydrogen can be sold at, in order for the project to break even. This figure was found from evaluating the costs related to the project, relative to the hydrogen production. The cost of increasing the installed capacity is proportional to the amount of modules that are purchased, and will have a linear increase in cost. However, the costs of liquefaction, equipment, and storage, are affected by economies of scale, meaning the costs will not increase linearly. In this analysis, the outputs are based on electrolyzer models M4000 and A3880, as these are the largest, and most cost effective models available from NEL. Table 4.7 displays the lowest LCOH of the two models, found at the point of optimum (cost vs production).

Energy [TWh]	Electrolyzer Model	Number of modules	Plant size [MW]	LCOH [€/kg]
1	M4000	8	160	5.89
	A3880	9	162	5.41
3	M4000	26	520	4.99
	A3880	29	522	4.56
5	M4000	43	860	4.71
	A3880	50	900	4.31

Table 4.7: Optimal LCOH at different plant configurations.

In the case of 5 TWh available wind energy, the alkaline model, A3880, reaches the lowest value at 4.31 €/kg. A3880 requires a lower LCOH than the PEM-based model, M4000, at all wind park sizes. This is a result of the price difference between the modules. In all cases, the electricity price was set to 30 €/MWh. The difference in LCOH is relatively stable around the optimal LCOH. Looking at the M4000, in the range of 840 to 1220MW, the LCOH is relatively stable, staying below a 1% increase.

Varying the cost of electricity

As shown in chapter 4.2.2, electricity price is a major factor in the profitability of the project, accounting for almost 40% of the overall project costs. Varying electricity prices will affect the cost of operating the plant. Figure 4.5 presents how different sets of electricity prices change the LCOH. This analysis was conducted on the M4000 electrolyzer module, with 5 TWh available wind energy.

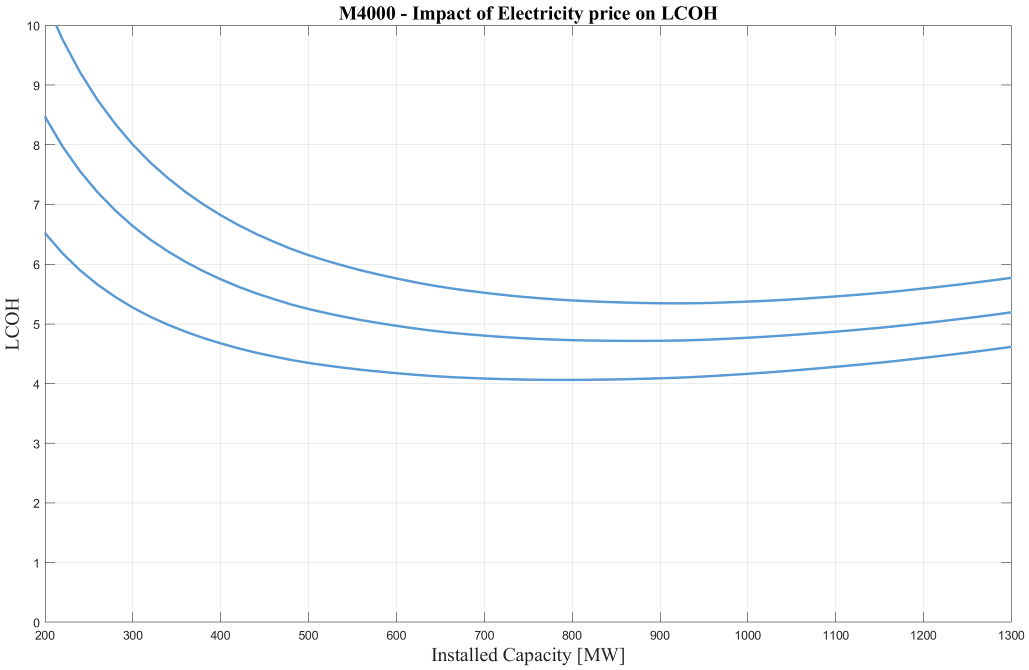


Figure 4.5: LCOH as a function of electricity price.

The graphs portray LCOH when electricity prices are 20, 30, and 40 €/MWh. The middle line, where the electricity price is set at 30 €/MWh, is the case that was presented in Table 4.7, with an optimal LCOH of 4.71 €/kg. The optimal amount of modules changes with a change in electricity price, thus changing the related LCOH. When lowering the price to 20 €/MWh, an LCOH of 4.06 €/kg is reached at 800 MW installed capacity. When increasing the price to 40 €/MWh, the LCOH and optimal electrolyzer capacity changes to 5.34 €/kg and 920 MW, respectively.

Cost reduction in electrolyzer CAPEX

PEM electrolyzers are expected to continue its decrease in price, thus lowering helping to lower a major share of the total investment cost. Figure 4.6 illustrates the impact of decreasing the cost of the M4000 module down by 50%, in increments of 10%. This decrease will affect the cost of the modules as well as the stack replacement costs. The cost of electricity is set to 30 €/MWh.

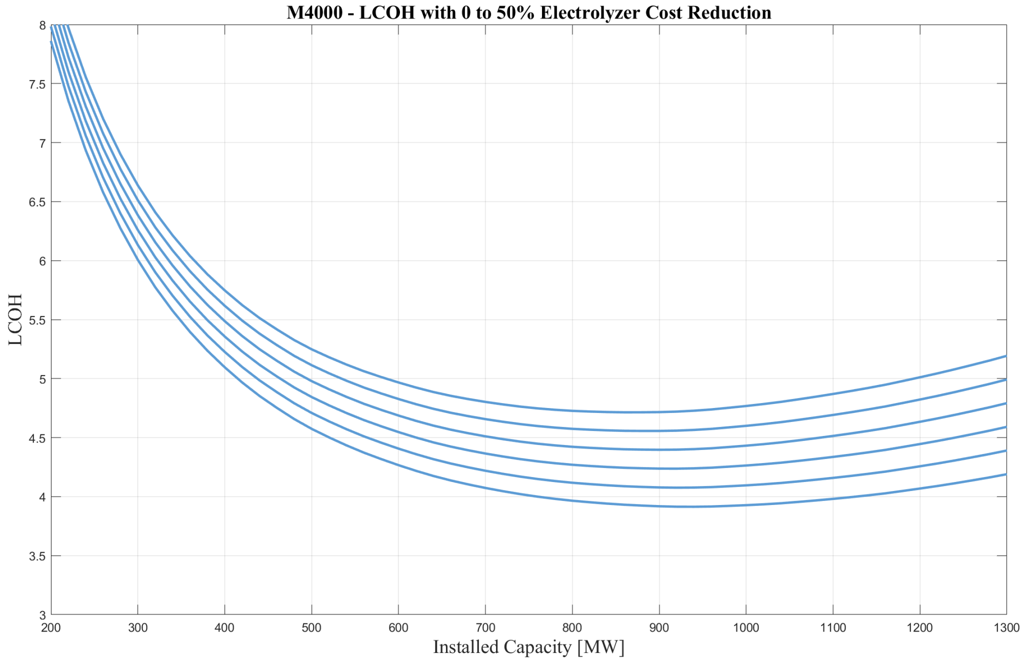


Figure 4.6: LCOH as a function of electrolyzer module cost reduction.

If costs were reduced by 20%, the LCOH drops by 6.6%; from 4.71 to 4.40 €/kg. Additionally, the optimal plant capacity is increased from 860 to 900 MW, although the LCOH remains fairly steady between 700 and 1000 modules MW. A 50% cost reduction lowers the LCOH to 3.91 €/kg, with an installed electrolyzer capacity of 940 MW. If no cost reductions take place, the optimal capacity is 860, as shown in Table 4.7. Lowering the electrolyzer CAPEX allows for larger electrolyzer plants, increasing the hydrogen production potential.

4.3.2 Discounted Payback Period

The previous section defined limits for the profitability of the project. In order to extract profit, the price at which the hydrogen is sold at, needs to exceed the LCOH. Table 4.8 displays the discounted payback period of the plants, at different selling prices. As the lifetime of the plant is 20 years, a periods larger than this would result in a net loss, indicated by a hyphen (-).

Energy [TWh]	Electrolyzer model	Total CAPEX [M€]	5€/kg [Years]	6€/kg [Years]	7€/kg [Years]	8€/kg [Years]	9€/kg [Years]
1	M4000	368.01	-	19.53	15.99	13.53	11.73
	A3880	362.74	-	17.43	14.33	12.16	10.57
3	M4000	939.60	19.95	15.68	12.92	10.98	9.55
	A3880	903.85	17.69	13.98	11.55	9.84	8.58
5	M4000	1350.60	18.46	14.54	12.00	10.21	8.88
	A3880	1401.26	16.37	12.96	10.73	9.16	7.98

Table 4.8: Discounted payback period of plants at different H_2 prices.

The discounted payback periods are calculated using an electricity price of 30 €/MWh. The alkaline module, A3880 results in a lower period under all simulated conditions. When simulating alkaline modules, ramp up time has to be considered. This does not, however, result in PEM modules producing cheaper hydrogen. The alkaline losses that comes as a result of the ramp-up time, thus slightly reducing the operational time, are limited to 1.9% at 1044 MW installed capacity.

4.3.3 Profit

This section will address the profitability of installing the electrolyzers. Return on investment, ROI, is used as a metric to assess the degree of profitability from the investments. Table 4.9 displays the ROI of the projects, using the same conditions as in Table 4.8.

Energy [TWh]	Electrolyzer model	Total CAPEX[M€]	5€/kg [%]	6€/kg [%]	7€/kg [%]	8€/kg [%]	9€/kg [%]
1	M4000	368.01	-	4.23	44.47	84.70	124.94
	A3880	362.74	-	26.43	70.98	115.52	160.07
3	M4000	939.60	0.46	51.57	102.68	153.78	204.89
	A3880	903.85	25.04	82.52	140.01	197.50	254.98
5	M4000	1350.60	16.18	72.79	129.41	186.02	242.64
	A3880	1401.26	43.67	106.77	169.87	232.98	296.08

Table 4.9: ROI of plants at different H_2 prices.

The LCOH defines the minimum selling price at which the plants can be considered profitable. Hence, hydrogen prices above the LCOH will result in profits. In cases where the price of hydrogen is higher than the LCOH, the ROI scales almost linearly. In view of the current marked price of liquid hydrogen being valued at 9 €/kg, all configurations would deliver substantial returns if installed today. Furthermore, the ROI's provide some elbow room in case of a decrease in marked prices. The related investment costs are displayed in Table 4.3.

4.4 Comparing Scenario 1 and Scenario 2

The results presented earlier in the thesis, assumed that the wind farm and electrolyzer plant were off-grid. This scenario promotes the utilization of more energy, causing an up-scaling of the electrolyzer plant. This is because the energy which not being used to run the electrolyzers, are considered to be lost. However, electricity costs are bound to the capacity of the wind farm, and are static. This section, however, will review how various elements of the analysis changes, if energy is bought from the wind farm at 30 €/MWh. This means that it is assumed that no energy is lost, and electricity costs are directly linked with consumption. The following simulations are based on the M4000 module, where one module have a capacity of 20MW, and a total of 5TWh available from the wind farm.

4.4.1 LCOH

When simulating an on-grid wind farm, the economical analysis changes in many aspects. Figure 4.7 illustrates the differences that occurs in the LCOH. The selling price of hydrogen is set to 7 €/kg.

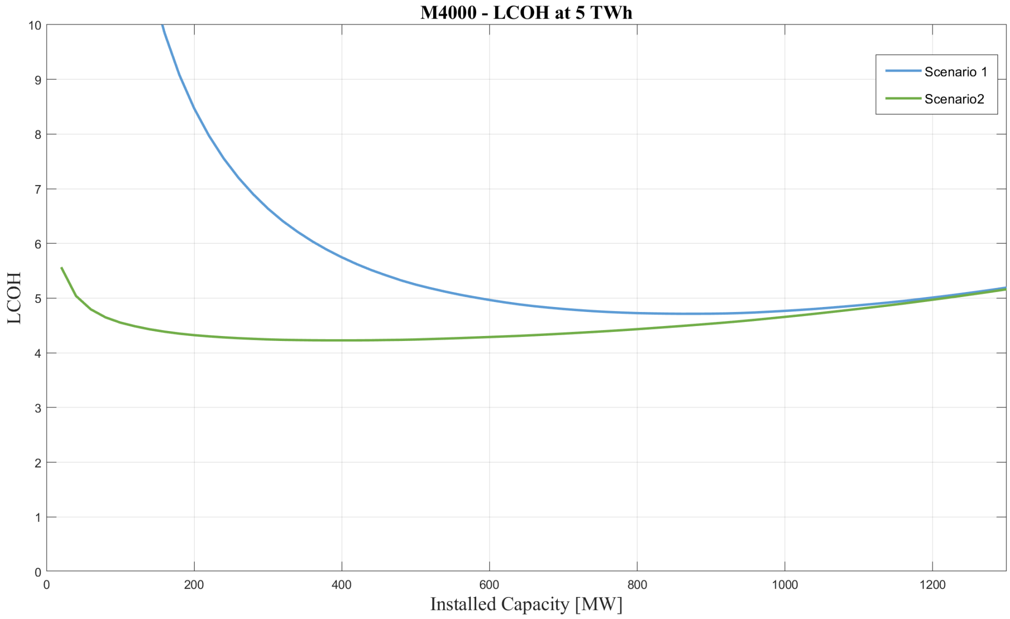


Figure 4.7: LCOH comparison between Scenario 1 and Scenario 2.

The green line represents the LCOH from the grid connected layout, scenario 2, and the blue line is the point of reference from chapter 4.3.1, representing the off-grid scenario. In addition to lowering the LCOH across the board, purchasing the electricity allows for smaller electrolyzer plants to be profitable. In this scenario, the lowest LCOH is 4.23 €/kg, compared to 4.71 €/kg in scenario 1. This results in 20 modules being installed for a total capacity of 400 MW, less than half of the optimal capacity in scenario 1 which was 860 MW.

4.4.2 ROI

In addition to having a lower LCOH, a grid connected plant will have larger profit margins due to the reduction in electricity costs. Figure 4.8 displays the disparity in ROI between scenario 1 and 2 for a selling price at 7 €/kg.

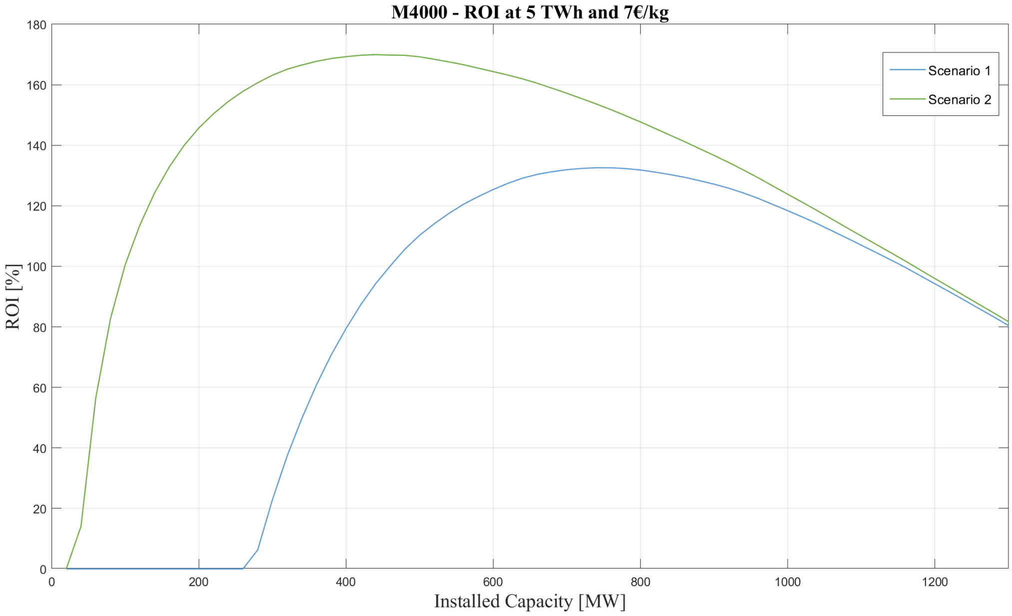


Figure 4.8: ROI comparison between Scenario 1 and Scenario 2.

The green line represents scenario 2, and the blue line is the reference from scenario 1. The optimal ROI occurs when the installed capacity is 440 MW. The resulting ROI is 170.0%. Scenario one provides an ROI of 94.2% at this capacity. Due to lower electricity costs, scenario 2 are resulting in an increase in profits compared to scenario 1.

In accordance with Figure 4.7, scenario 1 requires a minimum capacity of 280 MW to provide profit, with the resulting ROI at 6.27%. For the largest return of investment, 740 MW is to be installed, resulting in an ROI of 132.6%. Comparatively, the plant in scenario 2 would achieve an ROI of 153.6% at the point of optimum. Logically, a plant under scenario 2 conditions, will always be more profitable. However, as the size of the plant increase, the scenarios converge towards similar values.

5 Discussion

A discussion will be carried out in the following section. The methodology and results are evaluated and set against relevant theory to get a better understanding and overview of the conducted work. Considering the scope of the thesis, assumptions and choices had to be made underway. How these were decisions were made, and their significance on the results will be debated.

5.1 Case Evaluation

It is important for a thesis to have solid foundation from which it can be built upon. The foundation for this particular thesis can be said to be the stand-alone wind powered energy supply. With the wind-generated energy as the basis, the design and modelling of the hydrogen production facility could be executed.

5.1.1 Energy Available

The calculation of available wind energy was the starting point for any further calculation. It was decided that 1, 3 and 5 TWh worth of wind energy seemed like relevant starting points. Utilizing energy of such magnitude purely for green hydrogen production, is a large scale and offensive approach compared to previously existing cases, which made it a particularly interesting case study. For comparison, one of Norway's largest upcoming projects is set to utilize the surplus energy from Raggovidda wind farm in Berlevåg. This surplus energy is estimated to be approximately 0.6 TWh; considerably smaller than the values considered in this thesis.

In order to achieve the desired energy output, a wind farm analysis had to be conducted. Relevant data-sets for production values from already existing farms was provided by NVE's online wind resource page [28]. It was decided to use TrønderEnergi's wind farm located at Roan as the basis for further calculations. The reason for this was mainly based on the installed capacity of the park, which was the largest of the lot, and the fairly stable load factor of 40%. Data from Roans production from 2020 was analyzed using MATLAB, where production values for each day was plotted and used for further calculations. Roans initial capacity of 256 MW and 900 TWh was scaled up to reach values of 1, 3 and 5TWh, thus laying ground for further work. The accuracy of such a scale up is debatable, but was deemed sufficient enough. Scaling up could cause problems such as the possibility of decreased overall efficiency and load factor of the farm, as well as several public and governmental issues involved in such an expansion. None of which are being taken into account because the expansion of Roan itself is not the case for this thesis, but more of a general approach with Roan functioning as a real life model.

A power purchase agreement (PPA) was used to determine the cost of the wind generated electricity. PPA is a contract between the energy provider (owners of the wind farm) and the consumers (the hydrogen production investors). The contract is an agreement where the seller is obligated to provide a given amount of energy at a predetermined price. By doing this, the seller is insured a minimum sales price and will in turn provide an agreed volume of electricity to satisfy the sellers energy demand. The price was set to 0.03 €/KWh, or 30 €/MWh and is a value based on estimation from various market analysis.

5.1.2 Scenario Assessment

Having a stand-alone hydrogen production facility, where the electricity is provided purely by wind energy, requires a different approach compared to a grid connected system. This is caused by the intermittent nature of the renewables, where the energy output is not at a constant value, but operates in a more intermittent and less predictable way. Having an optimized hydrogen plant setup is therefore important in order to utilize as much of the energy as possible, but at the same time minimize the costs of investment and operation of the plant. If the plant design, that is installed capacity, does not cohere with the intermittent source of input energy, risks of low conversion efficiency and operability (high OPEX) and an under-utilization of the plant (high OPEX) becomes a problem. This is why having a holistic approach is so important, where the ratio of installed plant capacity vs energy output from wind needs to be optimized.

Scenario 1

In the first scenario, scenario 1, the energy produced (wind farm) and the hydrogen producers (investors) are said to be operated and financed by one common investor, with the purpose of utilizing all of the available energy provided from wind to produce hydrogen. In this scenario, the main object was to optimize the hydrogen production facility in order cut production costs, and make use of as much of the available energy as possible. It is based around the idea that the energy not being used for hydrogen production will go to waste. Because the wind farm and all of the related expenses comes at the investors expences, such a waste would mean money out the drain. It was therefore important to utilize as much of the energy as possible, in order to keep the losses at a minimum. This concept had to be combined with an optimized hydrogen plant composition in order to keep the LCOH as low as possible. Finding the right balance between energy going to waste and the right plant capacity became paramount. Even more so after having conducted the CAPEX and OPEX analysis, where it was determined that around 60% of the overall costs of the facility was caused by energy consumption. Scenario 1 constructs the main part of the thesis, and will be the focal point of the discussion, as it was in the results section.

Scenario 2

The second scenario, scenario 2, was approached from the eyes of the hydrogen production investors alone. In this scenario, the investors would only purchase the amount of energy needed for hydrogen production, without having to worry about any excess electricity going to waste from the wind farm. In this scenario, the object was to optimize the plant facility in combination with the production values generated from the wind. Combining the wind-energy-generation pattern with the installed capacity of the hydrogen production facility was important in order to fully utilize the resources at hand. Scenario 2 is included as a source of comparison to get a better understanding of the first scenario.

5.2 The Hydrogen Production Facility

This section will discuss every component and contributing factor involved in the hydrogen production facility. Starting off with production from the electrolyzers, all the way to treatment of the hydrogen product by liquefaction and storage. Water consumption and the plants aerial footprint will also be discussed.

5.2.1 Electrolyzer Consideration

To produce hydrogen from water electrolysis as efficiently as possible, several aspects and decisions must be taken into consideration. With the initial conditions already set as a stand alone system, finding a suitable electrolyzer composition able to perform and deliver at a respectable level was the next task at hand. As mentioned in the chapter 2.6, there are several electrolyzers that can be considered as a promising option for large scale application. Some of the most interesting ones are the Solid Oxide electrolyzer (SOEC), the Anion Exchange Membrane electrolyzer (AEMWE) and the Molten Carbonate electrolyzer (MCEC), neither one being analyzed through this thesis. PEMWE and AWE, however, are already at a more mature stage in the development and are commercially available for large scale production. These technologies therefore quickly became the only viable options for further use.

To make sure the hydrogen supply cost is lowered as much as possible, a holistic approach needs to be applied to the system and operational design. With a fluctuating energy source provided by wind, it demands an increased flexibility from the electrolyzers. In order to utilize both peaks and valleys, the electrolyzers must be able to shut down and start up quickly, as well as having an operational flexibility in terms of load range. Both PEMWE and AWE are able to operate under these conditions, like it was shown in chapter 2.6.3. The chapter presented load ranges from 10-110% and 0-160% for AwE and PEMWE respectively, with PEMWE being considered to be the more flexible technology out of the two. Having a load range from 0-160% allows the PEMWE to operate in overload and utilize energy surplus above the range in which the electrolyzer is initially dimensioned to handle. However, such an overload causes extra degradation and can be harmful for the stacks performance if its kept at this stage for longer periods of time. It does, however, allow for an increased flexibility if used correctly.

5.2.2 Optimal Plant Dimensions

Finding the optimal plant dimension means to locate the point of operation where production and cost are cooperative; getting the most amount of hydrogen for the least amount of money, by utilizing the available resources to its fullest extent. To determine the exact value of the installed capacity needed, a script was written in MATLAB. Every component in the hydrogen production plant was included, as well the available wind energy. By pairing the electrolyzer data with the energy generated from wind, the script allowed for calculations of daily production of H_2. The electrolyzers was set to utilize all available energy for each day, adding up over the year to give an annual production rate.

Electrolyzers come with a rated power requirement. The available options from NEL are of sizes ranging from 2 to 20MW as presented in the methodology chapter 3.3. A combination of several of the smaller modules of 2 MW, makes for a significantly more flexible electrolyzer plant than an equivalent plant size based on a combination of the larger 20 MW modules. This could be a drawback in terms of finding the true optimum plant dimensions, seeing as the plant capacity have less flexibility for adjusting to the right size compared to a scenario where the smaller modules would have been used. For the purpose of a large scale production it was decided to only make us of the larger modules, mainly based on the cost differences involved. This was done despite the fact that the flexibility of the installed capacity would suffer from not being able to utilize the smaller modules.

Load Factor and Installed Capacity

Two parameters that are closely linked together when considering optimal plant dimension, is the load factor and the installed capacity. Having a high electrolyzer utilization, yielding in a high load factor, reduces the share of the electrolyzer CAPEX to the overall cost of the hydrogen plant. That being said, a higher load factor will increase the energy consumption and thus also the electricity cost. The optimal point is, as mentioned above, where the hydrogen production cost is at its lowest. This is normally found between 3000 to 6000 hours of operation, coinciding with a load factor of 34-69% [4]. From MATLAB, the optimal load factors was found to be in the range of 49-53%, as shown in Table 4.2. This is within the predicted operational range. It is worth mentioning that a high load factor would typically mean an under-dimensioned electrolyzer plant, and vice versa for a lower load factor. In practical terms, a high load factor means a better use of the installed electrolyzer capacity, but at the same time risks not utilizing the full potential of the available energy. For scenario 1, mentioned above, this is a particularly important aspect, seeing as the energy not used for hydrogen production goes to waste. This signifies that a lower load factor, where more energy is utilized, is preferable. A load factor of 49-53% makes sense as the point of optimum as it provides a capacity that enables the balance between the amount of energy consumed versus energy wasted.

The installed capacities for the optimized plant was presented in Table 4.2, alongside the coinciding load factors. These numbers show a steady increase of plant size in correlation with an increased amount of available energy. For the 1 TWh of available energy scenario, plant capacities of 160 MW and 162 MW was found for the PEMWE and AWE system respectively, coinciding with a load factor of 58% for both of them. A recurring pattern is that PEM-based system has a lower installed capacity than AWE-based system, and this becomes increasingly apparent as the plant sizes increases. There are several reasons behind this. First of all there is the slight difference in module sizes (20 MW vs 18 MW) which makes for a less flexible sizing of the PEM system. Secondly, the price difference in the electrolyzer CAPEX makes the PEM system more expensive than the equivalent alkaline system. Lastly, there is the PEMWE's ability to run at overload, which makes it able to handle surplus power above its installed capacity for smaller periods of time, thus compensating for some of the flexibility losses due to the modular size-differences. A combination of these factors result in a slightly smaller installed capacity for the PEMWE system compared to that of the AWE system.

5.2.3 Production Values

If the world envisions to the future need for green hydrogen, the globally installed electrolyzer capacity needs a drastic increase. Plants like the ones laid out in this thesis, might be a part of the solution. At this time, world's total annual green hydrogen production are below 100 000 tonnes. Introducing new wind powered electrolyzer plants has the potential to exponentially increase this production.

With 5 TWh available wind energy, the PEM and alkaline plants both produce nearly enough liquid H_2 to double the worlds current production. Despite the losses caused by ramp-up time in alkaline electrolyzers, they still outperform the PEMWE modules. The AWE plant produces 82 690 tonnes, surpassing the PEMWE plant's production of 77 850 tonnes. However, wind farms with the capacities required to operate plants of this size are not abundant. Therefore, it is likely more realistic to install a greater number of smaller plants. This means that a 1 TWh-based production facility is more realistic than a 5 TWh-based production facility.

If an investor were to invest in hydrogen production in Norway today, there are no wind farms available to supply the largest electrolyzer plants. Thus, smaller plants would be needed. Considering that the LCOH of the 1 TWh plants are 5.9 €/kg in the PEM- based plant, and 5.4 €/kg in the alkaline-based plant, these investments would still generate a profit. The current retail price in Norway is 9 €/kg, and is expected to decline towards 7 €/kg in 2030. Combined with expected declines in capital costs for the plants, investment in smaller plants is a profitable option both now, and in the future.

5.2.4 Liquefaction

Hydrogen in its natural, gaseous state, does not satisfy the marked demands in terms of volumetric density. It is vital to process the hydrogen after production in order to achieve said standards, and be able to compete on the same grounds as other sources of energy like diesel, gasoline etc. There are, as mentioned in theory, several ways of doing this, amongst these are compression, ammonia, LOHC, and liquefaction, with the latter being analyzed throughout this thesis. Liquid hydrogen increases the density by a factor of 790, up to 71 kg/m^3 which makes for a competitive energy to weight ratio. The liquefaction process comes at a high cost. From theory it was shown that an ideal liquefaction process demands 3.9 KWh/kg, which is the minimum theoretical energy consumption when going from H_2 to LH_2. In practice however, the energy consumption is higher, normally in the range of 10-15 KWh/kg, which amounts to 30-40% of energy contained withing the H_2.

Energy consumption per kg of liquid hydrogen depends on the size of the liquefaction plant. For a large scale plant it would be reasonable to assume an energy consumption in the lower ranges, which is why 10 KWh/kg was used as a basis for the calculations performed regarding liquefaction. Amongst the methods considered for decreasing this energy requirement are; improved compression and expansion technology, heat exchangers, and new materials. Most of the liquefaction technology used today are based on 50 year old technology, and the potential for improvements are high. Reaching a liquefaction energy demand towards 5 KWh/kg is deemed technically feasible and would reduce the energy consumption involved in the process by half compared to today's achievable level. Seeing as the liquefaction process is an expensive part of the hydrogen production chain, such an improvement would be influential in terms of driving down the overall cost of the system.

Even though liquefaction is inefficient, and consume large quantities of the energy stored in the hydrogen, it was for the purpose of this thesis deemed to be the most relevant method for storing hydrogen. Compressed hydrogen is another viable option. With a less energy demanding treatment process, it might appear as the more favourable method out of the two at first sight. However, storing the CGH_2 pose several challenges because of its relatively low energy density, 75% less energy dense than LH_2 when compressed to 700 bar and also because of it being a high pressurized substance. These factors become increasingly apparent for large scale applications, where the storage becomes an issue in terms of cost and size. Liquefaction is the more expensive process out of the two, but because of the favourable attributes of the liquid product, it is considered the best option for large scale production.

5.2.5 Storage

Storing the liquid hydrogen is significantly less demanding than for compressed hydrogen. There are, however, still a few concepts and challenges worth mentioning. In order to store liquid hydrogen, super insulated vessels are needed because of the low maintenance temperature of 20K (-253 °C) needed to keep the substance liquefied. As theory mentions, boil off is a real concern and needs to be kept at a minimum. In order to achieve this, it is important not only to utilize highly insulating materials, but also to keep the surface-to-volume ratio of the storage tanks to a minimum. By doing this, the boil off rate can be lowered from 3-0.1%, which is significant when stored for longer periods of time.

Lowering the surface-to-volume ratio is done by increasing the volume of the storage units as well as optimizing the design. The liquid storage tanks are spherical or cylindrical, with capacities ranging from 400 kg to 145 tonnes of LH_2, with the 145 tonne tank giving a volume of 2300 m^3, roughly the same size as an Olympic-sized swimming pool. Having a tank at this size is not necessary for the production site assessed in this thesis, seeing as the storage tanks are dimensioned to satisfy an on-site storage capacity of 10 days worth of production. This equates to a capacity of 1 tLH_2 for the 1 TWh plants, 3.5 tLH_2 for the 3 TWh plants and 6 tLH_2 for the 5 TWh plants. The Norwegian-based company Linde, has a selection of storage units available on the market where the most relevant sizes are 0.4, 0.9 and 4.6 tLH_2. By combining these options, it is possible to achieve a satisfactory storage capacity for each plant scenario.

5.3 Water and Land Use

Large scale hydrogen production is resource demanding. Not only in terms of power consumption from electrolysis and liquefaction, or the material needs along the production chain, but also when considering water and land use. Electrolysis is the process splitting water into hydrogen and oxygen by inducing a current. The amount of water needed for this process is given by NEL, and are valued at 10 l/kgH_2, meaning that 1 kg of hydrogen requires an input of 10l of water. For the largest PEM-based plant analyzed in this thesis; utilizing the 5TWh energy source, this results in a water consumption of 827 134 tonnes per year 4.6. The annual water consumption of a Norwegian citizen is estimated to be 73 tonnes, or 200 l/day [115], meaning the water consumed by the hydrogen plant in question equals that of 11 000 Norwegian citizens. Providing such an amount of water is not considered to be a problem. In areas where municipal water resources are scarce, high quality and pure water can be obtained from desalination at an estimated cost less than 1% of the electrolyzer costs [116].

The land area use, or plant footprint, is another important aspect of the analysis. It is important to have an understanding of the actual size of the plant in order to make calculated decisions when finding the best suited location for production. From the calculations made, it was found that for the 5 TWh plant, the plant area was estimated at 0.083 km^2 for the PEM-system and 0.14 km^2 for the Alkaline system. For comparison, this would mean the need for an equivalent of 12 and 20 football fields respectively. It is estimated that around 60% of the footprint is occupied by the electrolyzers, and the rest being distributed between the liquefaction compartment, storage unit, various buildings and electrical components.

5.4 Collection of Cost Data

In order to make a viable analysis of the costs involved in a hydrogen production plant, a substantial cost collection was conducted. In the following chapters, the cost data obtained from various sources, as well as the necessary assumptions made along the way will be discussed. The costs are included in Appendix F and G, where the cost distributions are presented graphically, both CAPEX and OPEX. These costs coincide with the ones presented in chapter 4.2 in the results section.

5.4.1 Electrolyzer Costs

Investment costs, operational and maintenance costs, and stack replacement costs are all considered as part of the electrolyzer cost. Finding and determining the CAPEX cost was the first step in the cost collection process. As explained in the methodology chapter, this process needed a clear definition of the boundaries involved. Several sources were considered, and data from various literature was compared in order to make an accurate estimation of the electrolyzer CAPEX. Numbers ranging anywhere from 300 €/KW to 2200€/KW were found from the literature review. This uncertainty was resolved by looking at the boundary conditions, and getting a better understanding the aspects involved in the cost calculations.

The single most important parameter when evaluating the electrolyzer CAPEX is size. A larger module will be cheaper than a smaller one. This can be explained by having a look at the cost breakdown. The figures presented in chapter 3.5.2, shows that the BoP accounts for 55% of the electrolyzer cost, and the stacks makes up the remaining costs. A larger module will have a linear increase in stack costs, but the BoP cost will have a relative decrease. This is because the larger modules will have more stacks working under the same BoP. The effect of the decreased BoP expenses, is a lowered electrolyzer CAPEX for the larger modules. With this logical approach in mind, it makes no sense to operate with general values for the electrolyzers without considering the modular size, like it has been done in most of the literature found on the subject. The CAPEX should instead be found as a function of module size, where an increase in size corresponds to a decrease in price. By utilizing this method, CAPEX values was obtained from IRENA, as shown in Figure 3.3. A 2 MW PEM module is valued at 924 €/kW, compared to 512 €/kW for a 20 MW modules. For the AWE, the prices are 664€/ for the 4.5 MW module and kW438€/kW for the larger 20 MW module.

The operational costs normally include maintenance, both scheduled and incidental, as well as other necessary overhauling. The OPEX value are often based on a percentage of the CAPEX, and normally valued somewhere in the range of 2-5% of CAPEX per year. Every literature reviewed operated with numbers in agreement with these estimations, and a value of 4% was used for calculations conducted in this thesis. Using the same percentage for both PEMWE and AWE will lead to a higher OPEX cost for PEM because of its higher valued CAPEX. This might be inaccurate because there is reason to believe that the OPEX for the AWE system should be higher than for the PEMWE system. This is because alkaline system is submersed in acidic electrolytic solutions, which will lead to corrosion and deterioration of the materials involved. Extra maintenance is needed to avoid this, and will cause an additional OPEX. This is not an issue for the PEM-based system, where there are no moving fluids or liquid electrolytes that needs consideration. Despite these differences in operation and maintenance, it was decided to utilize the 4% OPEX for both the PEMWE- and AWE systems for the sake of simplicity.

Stack Replacement Costs

By setting the lifetime of the hydrogen production plant to 20 years, stack replacements costs could be calculated. The electrolyzer lifetime of 20 years is based on the life expectancy of the BoP components. During this lifespan, replacement of the stacks are necessary in order to maintain an efficient operation. This is because of the stack degradation as explained in 3.5.2. Data provided from NEL's brochures were used to decide the estimated time of operation before the stacks needs replacement. The data showed a stack replacement time of 78 750 hours for both Alkaline and PEM, or approximately 9 years of continuous operation. This is considered to be an optimistic estimation compared to IRENA's estimation of 60 000 hours for the Alkaline stacks and 45 000 hours for the PEM stacks. Seeing as NEL's electrolyzers were being used for the calculations, it was decided to use their estimations for stack replacement time, even though the numbers are in the upper range compared to other predictions.

The stack lifetime is based on continuous operation, with a load factor of 100%. This is not the case for a stand alone system, as it has been discussed above. To be able to predict the number of stack replacements needed throughout the lifetime of the system, the load factor must be considered. This is because the stack replacement cost is dependent on the stack replacement time, which in turn is dependent on the load factor of the electrolyzers. A high load factor; giving a high operational time of the electrolyzers, means more stack degradation and therefore also the need for more frequent stack replacements. The results section showed calculations for load factors in the range of 57-59% for the optimal plant designs. This equates to an operational time of 15.2-15.8 years, meaning that the stacks only needs replacement every 15.2 to 15.8 years, or 0.77-0.79 times per lifetime.

Changing each stacks 0.845 or 0.915 per lifetime does not make any sense at first sight. These numbers are found based on the assumption that every stack in every module is operated equally throughout the operational time of the system, which is not the case when considering a real-life plant. At times when there are not enough available energy to power up all of the installed electrolyzers, only a fraction of the modules will be switched on whereas the rest will remain shut down. This means that certain modules will degrade faster than others, and will need a more frequent stack replacement. This differentiation means that the stack replacement time can be modified to the point where some of the modules need replacement after 9 years (being operated continuously) and others don't need replacement at all.

5.4.2 Liquefaction Costs

Finding the liquefaction costs was done by researching relevant literature. As of today, liquefaction is not as widespread as compression of H_2, so there weren't as much data on the subject compared to the what was found for compression. Many of the sources dated back to the early 2000's, but there were also some relatively recent data, dating back only a few years. An interesting notation is that the estimations from the early 2000's are on the cheap end of the cost projections compared to the newer data. These findings can be linked to the liquefaction section above, where it was stated that the liquefaction technology has been in a stand by mode with little to no development over the last 50 years. A cost reduction would therefore not be expected in recent studies.

The liquefaction plant displays an especially strong economics of scale, with scaling factors found from literature ranging between 0.57-0.77. This means that the liquefaction cost will decrease with the size of operation. Because liquefaction is such an expensive way of treating the hydrogen, the cost reduction becomes an important part of any investment strategy. In order for the liquefaction to become cost competitive, a medium to large scale hydrogen production facility is required. This is the point where the economy of scale starts to kick in, helping the investment reach a more feasible level. This occurs for plants with a production larger than 5 tonnes of hydrogen per day (tH_2/d). The calculations for the various plant sizes and compositions done in this thesis, gives an annual estimated production of 42-247 tH_2/d, meaning that liquefaction can be considered as a suitable option. The OPEX is accounted for in the cost calculations, and are estimated at 8% of the overall costs.

5.4.3 Storage Costs

To find the storage costs involved in the hydrogen production plant, it is important to first determine the amount of storage necessary. The capacity was designed to satisfy 10 days worth of LH_2 production at max load, meaning that the units had to be dimensioned to be able store the amount produced throughout 10 days of continuous electrolyzer operation at full load. As previously discussed, this is not how the electrolyzer operate in reality because of the fluctuating energy source and therefore also a fluctuating production. It is still important to have the storage units dimension based on the max theoretical production.

The storage cost was calculated an presented for each hydrogen plant composition, as presented in 4.3. The CAPEX percentage of the overall costs remains roughly the same regardless of the installed capacity of the electrolyzers. This is as expected, seeing as the storage capacity necessary increases with plant size and hydrogen production rate. Because of the low scaling factor of 0.95, the storage costs increases close to linearly. The total CAPEX contribution of storage costs is 3.4-4.8%, as shown in Appendix F. A small amount compared to the other cost contributors.

An OPEX value of 4% of the storage CAPEX was used in accordance with values found from various literature. This expense is set to cover various maintenance of the storage units to make sure they are fully operational throughout their lifetime. The lifetime of storage units are assumed equal the lifetime of the hydrogen production plant, at 20 years. Having a fully operational storage unit is a key part of the hydrogen production chain. If the storage units are unable to operate, the hydrogen process would come to a halt seeing as there would be no where to store the hydrogen. It is therefore vital to include the operation and maintenance cost for the hydrogen storage units.

5.4.4 Other Costs - Non Equipment Costs

The final component also considered to be part of the CAPEX calculations, are the non-equipment costs, also known as other costs. The non-equipment costs are defined as additional costs required for installation and operation of the hydrogen plant, other than the aforementioned equipment costs (electrolyzers, liquefaction plant and storage units). Important parts such as engineering, administration, construction work, planning, operation, piping and interconnection were all included under this cost component.

Instead of trying to find the exact cost of each segment, a cost model provided from FCH was used. The resulting CAPEX showed an estimated cost contribution of around 20% of the overall cost, as presented in Appendix F. It is difficult to determine whether or not this number is valued correctly, simply because of the lack of precision and details in the cost model. To get an accurate representation of the other cost contribution, each part should have been analyzed individually. However, such an in depth analysis would exceed the scope of this thesis, meaning that the FCH model was utilized regardless of its potential inaccuracy.

5.4.5 Electricity and Water Cost

The electricity and water costs are considered as operation and maintenance cost, with neither one of these being included in the CAPEX calculations. Both water and electricity consumption is dependent on the amount of hydrogen that is produced, and will increase in value proportionally to an increased production rate.

Electricity Costs

Determining an accurate estimate for the price of electricity is no easy task, and is subject to some degree of uncertainty. The electricity costs from wind farms in the Nordic countries are typically in the range of around 30 €/MWh. In agreement with the PPA analysis of various market actors, the value was chosen to be the price of electricity used for the calculations performed in this thesis. Its worth noting that these cost projections are defined for a grid connected system. For an off-grid system, i.e scenario 1, the 30 €/MWh may be an overestimation because of a reduction in grid fee investments (no grid fees in an off-grid scenario), which will lead to a lower price point. This is taken into account in the sensitivity analysis performed, where a set of different electricity costs are analyzed.

Water Costs

The price of water are, much like the price of electricity, a subject of uncertainty. Water prices vary across the country, and are determined on a municipal level. Instead of trying to determine a price of water based on individual Norwegian municipals, it was decided to use a price estimation based on a variety of factors. The prices of water was set at 2 €/m^3. This figure represents a compromise between the cost of Norwegian tap water, desalination, and industry. Compared to the other components in the plant, the cost of water has a low impact on the end result, only contributing to about 0.6% of the total OPEX. Some uncertainty was therefore regarded as acceptable when defining the cost of water.

5.5 Economical Analysis

The accuracy of the results depends on selecting the correct cost factors. With varying sources having differing claims, choices had to be made. This section will shed light on how these factors were chosen, and their impact on the final result. Furthermore, an analysis on the profitability of the investment, and how future improvements and developments might change the outcome, will follow.

5.5.1 CAPEX and OPEX

The CAPEX and OPEX are presented in the results section 4.2, as well as presented graphically in in Appendix F, G and H, where the two former shows the CAPEX and OPEX distribution and the latter show the distribution of CAPEX vs OPEX. All of the electrolyzer compositions are shown in accordance to the available energy; 1, 3 and 5 TWh. For the largest PEM-based system consisting of an installed capacity of 860 MW, with access to 5TWh worth of energy, a total CAPEX of 1 350 M€ and a total OPEX over the 20 year operational time of 2 248 M€ was calculated. This is without a doubt a large investment that needs to be bring in a substantial amount of income in order for it to be considered feasible. Whether this is realistic or not, will be discussed in the following sections.

CAPEX

It is interesting to analyze the cost distribution from the various components involved in the production chain. From the appendices mention above, it can be seen that there are three main contributors to the CAPEX; electrolyzers (40.8%), liquefaction (34.7%) and other costs (20.3%), with storage cost only making up 4.2% of the total CAPEX (for the 5 TWh PEMWE-based system). This is as expected, with the electrolyzer and the liquefaction process being the most expensive pieces of investment. Seeing as the other costs are found as a percentage of the equipment (electrolyzers, liquefaction plant and storage compartment) it is also natural that this cost is substantial. The cost of storage is low, also as expected, because of the liquefied state of hydrogen which means that there are less requirements in terms of storage volume and materials used. The low storage costs makes up for the high liquefaction costs. This becomes especially apparent as the plant size increase, as can be seen when comparing the CAPEX distribution for the 1, 3 and 5 TWh scenarios. As the plant size increases, the liquefaction cost decreases; going from a total share of 27.5% in the 1 TWh scenario to 20.3% in the 5 TWh scenario as a result of economies of scale. Consequently, the electrolyzers will occupy a larger share of the total costs seeing as there are no gain from an increased plant size for the electrolyzers (no economies of scale effect).

OPEX

The OPEX is given as an averaged annual value, derived from the total OPEX over the 20 year lifetime of the hydrogen production facility. The annual values will vary from year to year as a result of the discount rate of 8%. For the sake of simplicity, the values have been averaged to give a representation of the annual operating expenses. Again, using the largest PEM-based system that is optimized for 5 TWh available energy as reference, it was found that the single largest contributor to the total OPEX was cost of electricity, with a total share of 65.5%. This goes to show that the price of electricity is a vital part in determining the overall costs, and need to be kept as low as possible in order for the operation to become feasible.

5.5.2 LCOH

Determining the cost of production is an integral part in any business model. It is important to get an idea of the expenses that can be expected by the investment before taking the leap from idea to implementation. By calculating the levelized cost of hydrogen, the production costs per kg hydrogen can be estimated. The LCOH can be use for several down-stream analysis to help unveil the market potential of the production and evidently determine whether or not an investment has the potential of being profitable.

Assessment of the LCOH

The calculations for LCOH can be found from Table 4.7, presented in the results section. The LCOH is given for each plant composition; 1, 3 and 5 TWh available energy for both PEMWE and AWE systems. There are two trends worth noticing; the first one is that the AWE systems are consequently cheaper than the equivalent PEMWE systems. This is mainly because of the less expensive CAPEX of the AWE compared to the PEMWE (about 20% cheaper), and also the differences in energy consumption (about 10% less for AWE compared to PEMWE). The difference in price leads to a difference in plant composition. Take the 5 TWh case for an example; a lowered CAPEX for the AWE electrolyzers compared to the PEMWE electrolyzers allows for a larger installed electrolyzer capacity for the same amount of money. This will in turn yield a larger production volume, which lowers the LCOH (investment vs production). The two most competitive LCOH values was found in the 5 TWh available energy scenario, with the AWE valued at 4.31 €/kgH_2 and the PEMWE valued at 4.71 €/kgH_2. Although the differences are not to great (about 9%), the Alkaline system still have the advantage of being the cheapest solution as of today.

The second trend is the one caused by the economies of scale. A larger installed plant capacity leads to a decrease in LCOH. This becomes obvious when evaluating the LCOH at the different plant sizes. At 1,3 and 5 TWh, the PEMWE system are valued at 5.89, 4.99 and 4.71 €/kgH_2 respectively. This decrease is caused mainly by a drop in other costs and liquefaction costs as a result of the scaling factors. These two components makes up about 70% of the total CAPEX in the 1 TWh scenario, and decreases to about 55% in the 5 TWh scenario as shown in Appendix F, thus decreasing the overall CAPEX and, consequently, the LCOH.

Importance of the Electricity Price

The price of electricity is not constant, and it is important to take this into account when analyzing the feasibility of hydrogen production from green electricity. This becomes even more important when considering how much of an impact the cost of electricity have on the total cost of hydrogen production; around 60% of the total OPEX and about 40% of the total cost, as previously discussed. As a result of this, it was decided to perform a sensitivity analysis to examine how the LCOH is affected by a changing electricity price. Figure 4.5 plots the LCOH for three sets of electricity prices: 20 €/MWh, 30 €/MWh (the basis for all of the calculations in this thesis) and 40 €/MWh. The plots were based on the 5 TWh, PEMWE system and resulted in a LCOH of 4.06 €/kgH_2, 4.71 €/kgH_2 (as previously analyzed) and 5.34 €/kgH_2, respectively. As expected was the lowest LCOH found from the cheapest electricity price, only adding to the already stated fact that the cost of electricity is a central part of the cost of hydrogen production.

The sensitivity analysis allows for a deeper insight and a better understanding of the variable that is cost of electricity. It is a great analytic tool and provides an additional security from an investors point of view, allowing for cost projection at number of different electricity prices. The estimates show that production can be profitable, and therefore also considered feasible, for a number of prices. Even at an estimated LCOH of 5.34 €/kgH_2, at a electricity price of 40 €/MWh, the production still have the possibility of being profitable if the hydrogen is sold at the right price. This will be discussed subsequently.

Cost Reduction in Electrolyzer CAPEX

As previously discussed, one of the main reasons for the LCOH of the AWE system being cheaper than the PEMWE system, is the differences in the electrolyzer CAPEX. with AWE being cheaper than the PEMWE. An interesting analysis is to see what will happen if the cost of the PEMWE electrolyzers were to decrease. Seeing as the PEM technology is yet to obtain a mature level of development, a decrease in cost is to be expected over the coming years. Figure 4.6 plots the LCOH as a function of cost reduction in the electrolyzers. The plots are based on the 5 TWh PEMWE system. As previously stated, the PEM electrolyzers are about 20% more expensive than the alkaline ones - which evidently lead to the AWE hydrogen production plant being cheaper than the PEMWE plant. Interestingly, if the PEM electrolyzer CAPEX decreases by 20%, thus nullifying the cost differences, the resulting LCOH calculations results in a value of 4.40 €/kgH_2, down from 4.71 €/kgH_2 at the original price point. The decrease in LCOH is still not enough to come down to the level of the AWE system, set at 4.31 €/kgH_2 because of the differences in energy consumption during electrolysis.

A 50% cost reduction in the electrolyzer cost results in a LCOH of 3.91 €/kgH_2. In other words, a price reduction of 50% of the electrolyzers only results in a 20% reduction in the LCOH. Even though the cost of the electrolyzers are important and needs to be reduced, it does not affect the overall cost in the same way that the price of electricity does.

5.5.3 Profit

A hydrogen plant of the size envisioned in this thesis, requires a substantial amount of capital investment which would be tied to the project for a considerable amount of time. The discounted payback period determines how long an investor would need to wait on order to extract profit from the initial investment. Taking the future value of money into account, it provides a reliable estimate of how many years one would need to get the money invested in return. After the investment is paid off, the difference between OPEX and sales is solely profit. This thesis focused on ROI as a measure of the overall profitability of the plant. ROI lists the profit as a percentage, and was considered to contribute to a better base of comparison when discussing different plant compositions.

Calculations for the PEM electrolyzer plant, with 5 TWh available wind energy, demonstrates that if the selling price remains at 9 €/kg, one would need 8.9 years to pay off the investment, meaning that an investor could expect more than eleven years of profit on the investment. This is more than half the lifetime of the plant, assuming production lasts for 20 years. In this case, the return on investment exceeds 240%. If future hydrogen prices were to decrease, the plant would still remain profitable until the selling price sinks below the LCOH. With the largest PEMWE-based system in mind, that price is 4.71 €/kg. A reduction of almost half today's selling price of liquid hydrogen.

The amount of available wind energy, and the selling price of hydrogen, govern the profitability of the plant. More available wind energy yield more cost-effective solutions. Naturally, higher selling prices increases the profitability. At the same time, higher electricity prices directly affects the profits negatively.

Today, the price of liquid hydrogen is somewhere between 7.1 and 14 €/kg. By itself, it is clear that the electrolyzer plants presented in this thesis will be able to turn a profit. At the same time, judging from costs alone, traditional production is a better option. Producing green hydrogen costs approximately double, when comparing to production by coal and natural gas. Brown and grey, and to a lesser extent blue, hydrogen is a more cost effective way of production. However, in meeting the climate goals of the future, green is the way to go. Not only by being the most environmentally friendly production method, it also meets the future demands set by the EU.

Scenario 1 vs Scenario 2

Large amounts of renewable energy resources are located in places where the electrical grid's capacity is inadequate, in locations where distance to the grid hampers the construction of the renewable electricity production. Green hydrogen plants offer a possible solution to this issue. The two main requirements of hydrogen plants is access to water and energy. Provided that sufficient water is available, construction of green hydrogen plants is a possibility in remote locations, without having to be connected to the grid.

Scenario 2 offers an alternative in locations where the wind farm have the opportunity to be connected to the grid. Removing the cost of unutilized energy increases the profit across the board. As seen in Figure 4.7, displaying the LCOH differences between the two scenarios, it is shown that scenario 2 outperforms scenario 1 when applicable. If one were inclined to make use of all available wind energy, it is necessary to match the electrolyzer capacity with that of the wind farm. This would decrease the difference in profits between the scenarios, as there is less surplus energy.

A scenario 2 plant is more profitable when constructing smaller plants. When installing fewer modules, they are better able to utilize the available wind energy. This increases the amount of hydrogen being produced per module, thus decreasing installed capacity of an optimal plant. Building a smaller plant also demands less capital, potentially attracting a wider array of investors. Even though a scenario 2 plant is more profitable, the location of the plant is limited in a way which scenario 1 plants are not. Scenario 1 plants can be constructed in remote locations, while still providing profit. However, if the conditions are favorable, scenario 2 performs better. Excluding the cost of unutilized wind energy, will be the more profitable solution.

5.6 Making Green Hydrogen Cost Competitive

In order for the hydrogen economy to be considered a realistic future pathway, it is vital that the green hydrogen production are able to lower the costs involved in production. In order to reach this level of competitiveness, improvements all along the production chain is necessary, with some of the most important aspects including an increased electrolyzer manufacturing scale, various R&D, and a drop in costs from renewable energy.

Manufacturing

It has been shown that by scaling up the hydrogen production facility, a cost reduction can be obtained, primarily as a result of a reduced impact from the balance of plant costs. Another important sector where a scale up can lead to a significant cost decrease, is in the manufacturing process of the electrolyzers. Large manufacturing volumes with an increased production rate can lead to a decrease in cost. This comes as a result of an automated mass production of electrolyzer cell components, which leads to a lowering in the specific cost of the stack. The automated mass production will bring down the cost of the electrolyzer components, whereas an increased module size will help bring down the balance of plant costs. A combination of the two can lead to a drop in the overall price for the electrolyzer systems. Investments are already underway. NEL is currently in the process of expanding the capacity of their electrolyzer production facility at Herøya, Porsgrunn (Norway) from 40 MW/year to 500 MW/year, with the possibility to expand up to 1 GW/year [3]. A scale up to reach 1 GW/year production capacity is thought to be enough to reach economy of scale effects, thus lowering CAPEX of the electrolyzers to an acceptable level. The CAPEX values used for calculations in this thesis were valued at a cost of 520 €/KW for PEM and 438 €/KW for AWE. A significant CAPEX decline is expected by 2030, with a drop to about 150-250 €/KW for both technologies. [10].

R&D

The research and development (R&D) area is as always a highly promising field when it comes to making improvements in the production department - evidently leading to a cost reduction, as a result of a better operational electrolyzer system. The focus area for the alkaline electrolyzers is to try and increase the current density (to achieve higher production rates), try to minimize the diaphragm thickness (to reduce resistance, and therefore achieve higher efficiencies) and improve the electrode- and catalyst design. For PEM - which is the less developed technology out of the two, potential advancements comes from research and improvements of the bipolar plates (provides mechanical support to the cell as well as distribution of the H_2 and O_2 flow). The main focus should be on trying to make the electrolyzers more efficient. If there is a trade-off between cost reduction in the electrolyzers system vs an increased efficiency, the latter should be prioritized. This is because efficiency is in direct correlation to power consumption, which as has been discussed, is the number one contributor to the overall cost of the hydrogen production facility. Increasing the electrolyzer efficiency,and thus lowering the energy consumption, will lead to a decrease in cost for production of hydrogen.

Cost of Electricity

As previously discussed, cost of electricity is the main contributor to the overall cost of a hydrogen production facility with a total share of around 60%. This is why it is crucial that the electricity costs from renewables are kept at a minimum. If the price of renewables drops additionally from the level it is at today, green hydrogen production will become increasingly cost competitive. There are already signs of a declining levelized cost of energy (LCOE) in renewables world wide, with both wind and solar experiencing significant drops over the past decade [10]. This trend is expected to continue - aided by a global renewable scale up, and will be extremely important in the quest of achieving a cost competitive green hydrogen production.

6 Conclusion

In this thesis, a wind-to-hydrogen system has been analyzed and modeled for an off-grid case study. A feasibility study has been conducted to determine the viability of green hydrogen production powered by a dedicated wind farm. Production data from Roan wind farm has been used and scaled up to meet the pre-determined production of 1, 3 and 5 TWh. These hypothetical wind farms provided the foundation in which the hydrogen production facility was built upon. The simulation software MATLAB was used to design and simulate the wind-to-hydrogen scenario in order to get better understanding of the system in its entirety. A literature review was conducted in order to obtain the necessary data needed to perform the calculations. From the simulations, values of wind power output, electrolyzer plant size, and the total hydrogen production from the time-varying wind generated energy was found. Additionally, an economical examination including several sensitivity analysis was performed to provide a higher degree of certainty in the results. LCOH, NPV, ROI, profit and discounted payback period were all calculated and analyzed.

The methodology was based upon cost data found from a literature review. By doing this, CAPEX and OPEX for all the components involved in the hydrogen production facility was found. This included the electrolyzers, liquefaction, storage and other costs. The lifetime of the plant was set to 20 years, and the cost of electricity at 30 €/MWh. These initial values were all obtained from the cost data gathering, and served as input into the plant simulation tool. From the simulations, an optimization of the plant size, where investment costs meats production was found for every scenario; both 1,3 and 5 TWh of available energy. Two electrolyzer technologies were analyzed; PEMWE and AWE. AWE modules are cheaper in terms of electrolyzer CAPEX, but are considered less flexible as a result of an extended ramp-up time and a shorter load range. This gives PEMWE an advantage when coupled to an intermittent energy source like the off-grid wind farm in question. Hydrogen production is affected by economies of scale, which is why analysing three large scale scenarios was especially interesting.

The most cost-competitive LCOH was found in the largest scenario, at 5 TWh available energy, with the lowest value at 4.31 €/kg provided by the AWE-based system. The competing PEMWE system were able to deliver a LCOH at 4.71 €/kg, a price point 9% higher. From these results, it is unquestionable that the Alkaline electrolyzers have an advantage in terms of economies, and are able to out-compete the more flexible PEM electrolyzers to give the most cost efficient end-product. These differences will, however, be nullified within the next couple of years when the cost of the PEMWE will drop to reach the level of the AWE, meaning that the PEMWE system have a higher potential than its competitor, already having the advantage of being the more flexible option.

By repeating the motivation behind the thesis, some conclusive thoughts can be drawn. The motivation reads as follows:

"Is it feasible to produce hydrogen from electrolysis
- entirely supplied by wind-generated energy?"

From the LCOH analysis, it was found that a break-even cost can be obtained at around 5 €/kg. This means that profits can be made if the selling price of hydrogen is above this value. An important side note is that the cost of delivery and distribution has not been included in the calculations, meaning that a price point above the 5 €/kg-mark is a more realistic scenario.

This has not been accounted for in this thesis. From the discounted payback period analysis, it was found that the production are profitable for a number of price points. Prices ranging from 5-9 €/kg were all analyzed to determine the potential profit at each scenario.

To determine whether or not large scale green hydrogen production is feasible, several parameters needs to be taken into account, and certain questions needs to be raised: Is there enough available renewable energy at hand? Are the production costs at a feasible level? At what price point can the hydrogen be sold for? Is there a market for the produced hydrogen, and if so, can it be delivered? These are questions that have no definitive answer. From a purely productional point of view, the large scale implementation can be considered feasible. The electrolyzer technology is able to operate in combination with an intermittent renewable energy source to produce hydrogen on demand, and at a reasonable price point, thus being capable of providing green hydrogen at large scale. There are, however, still room for improvements both technologically and economically. R&D will play an important part in terms of improving both the electrolyzer- and liquefaction technology in order to increase efficiencies and lower costs. The same applies for the price of renewable energy, which is a determining factor in the overall cost of production.

Perhaps the largest takeaway from this thesis, is the importance of scale. The LCOH is highly affected by the size of the hydrogen plant, meaning that in order to achieve cost competitive hydrogen prices, a large scale implementation is key. For a large scale production to be considered feasible, there has to be a market demand for the hydrogen that are being produced. As of today, the demand is covered by cheaper sources of hydrogen produced from fossil fuels. In order for this to change, political incentives aiding the green pathway must be formed to make green hydrogen the better option, both economically and environmentally. A shift towards the green hydrogen economy is a key part in the implementation of large scale green hydrogen production. The technology is already available, and will only continue to improve, now it is about initiating the scale-up to truly be able to take advantage of green hydrogen as an energy carrier.

7 Further work

Hydrogen production offers a wide range of opportunities, as well as challenges. As a result of the relatively limited scope of this thesis, several interesting areas have not been properly investigated. The following section presents some of the cases that are subject for further research.

Location

Large scale hydrogen production requires a substantial amount of energy. A 5 TWh production facility would require an installed wind farm capacity of around 1 374 MW. Put into context, today's total installed wind capacity in Norway is 3 977 MW, per 2020. A feasibility analysis of such a large scale wind farm implementation is in other words imperative.

Ammonia

Liquefaction was chosen as the hydrogen processing method for this thesis. Another highly promising approach would be by conversion to ammonia. A feasibility analysis of ammonia produced from green hydrogen would be interesting, even more so as a source of comparison to the findings in this thesis.

Distribution of Hydrogen

There are three ways of transporting hydrogen, by trucks, pipelines or ships. An increased demand are expected in regions such as Europe, Korea, Japan etc, and finding the best way of transporting the hydrogen are becoming increasingly important. A study of the various methods of transportation, as well as the costs involved needs to be undertaken.

Cost of Electricity

Using LCOE to estimate the price of electricity is a good estimation, but do not provide an exact measurement. By doing a complete analysis of the costs involved in the wind farm, one would be able to pin-point the price of electricity with precision; thus increasing the level of accuracy in the LCOH calculations.

Grid Costs for Scenario 2

As a source of comparison to the off-grid hydrogen production facility analyzed in this thesis, a second scenario was introduced; scenario 2. This is a grid connected scenario which means additional grid fees will come into play. This was excluded from the calculations, but should be taken into consideration at a later stage.

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A Electrolyzer Data

Company	Type /model	Module size	Production rate [Nm^3/h]	Production rate [kg/h]	Energy cons. [kWh/kg]	Output pressure [bar]	Module size [m^2]	Source
NEL	Alkaline: A1000	5	970	85	47	30	350	[111] [117]
NEL	Alkaline: A3880	18	3880	341	47	30	770	[111] [117]
NEL	PEM: M400	2	413	36	51.5	30	160	[111] [117]
NEL	PEM: M4000	20	4000	352	51.5	30	540	[111] [117]
Thyssenkrupp	Alkaline	10	2000	176	48.9	-	-	[118]
Thyssenkrupp	Alkaline	20	4000	352	48.9	-	-	[118]
Cummins	PEM: HySTAT-100-10	0.5	100	8.8	61.4	10	15	[119] [120]
Cummins	PEM: HyLYZER-1000-30	5	1000	88	48.9	30	200	[119] [120]
Cummins	PEM: HyLYZER-4000-30	20	4000	352	48.9	30	500	[119] [120]
ITM Power	PEM: HGASXMW	10	1918	169	59.7	20	280	[121] [122]

Table A.1: Electrolyzer data presented by various market developers.

B Electrolyzer Module Costs

Cost projections for electrolyzers based on modular size. The values are given by FCHJU, and are estimates for the cost in 2017 as well as future predictions for 2025. Both PEMWE and AWE cost projections are presented in Table B.1 and B.2, respectively. Additionally, Table B.3 present estimations for OPEX from various sources.

Electrolyzer	**Module [MW]**	**CAPEX 2017 [€/kW]**	**CAPEX 2025 [€/kW]**
PEM	1	1500	1000
PEM	5	1300	900
PEM	20	1200	700

Table B.1: CAPEX for PEMWE given by FCHJU [110].

Electrolyzer	**Module [MW]**	**CAPEX 2017 [€/kW]**	**CAPEX 2025 [€/kW]**
Alkaline	1	1200	900
Alkaline	5	830	600
Alkaline	20	750	480

Table B.2: CAPEX for AWE given by FCHJU [110].

OPEX [% of CAPEX]	**Source**
2	[8], pg 20
2-4	[110], pg 49
2-5	[106], pg 9

Table B.3: OPEX for electrolyzers given by various sources.

C Stack Replacement Costs

Projections for the current price of stack replacement as well as estimates for future prices in 2025. Costs are given by FCHJU.

Technology	Module size [MW]	Stack repl. 2017 [€/kW]	Stack repl. 2020 [€/kW]	Stack repl. 2025 [€/kW]
PEM	2	525	441	300
PEM	5	470	388	250
PEM	20	420	341	210

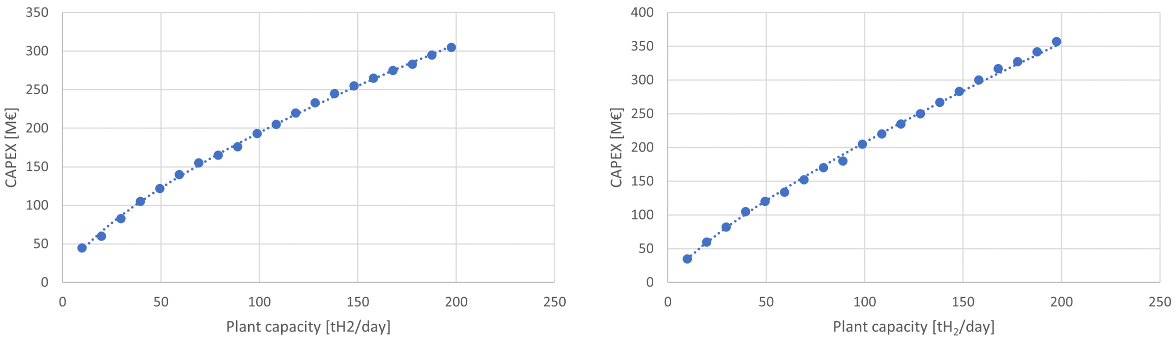
Table C.1: Stack replacement cost for PEMWE [110].

Technology	Module size [MW]	Stack repl. 2017 [€/kW]	Stack repl. 2020 [€/kW]	Stack repl. 2025 [€/kW]
Alkaline	2	420	381	315
Alkaline	5	380	339	270
Alkaline	20	338	292	216

Table C.2: Stack replacement cost for AWE [110].

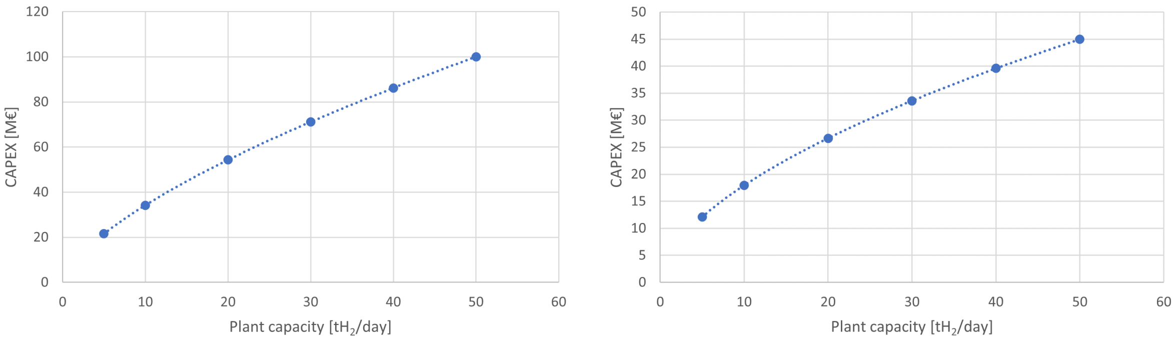
D Liquefaction Cost Models

Graphic representation of four different cost models for liquefaction of hydrogen. Out of the four options, cost model 3 was chosen as the basis for calculations performed in the thesis.



(a) Cost model 1 [114], fig 4 pg 297.

(b) Cost model 2 [114], fig 4 pg 297.



(c) Cost model 3 [110].

(d) Cost model 4 [112], table 2.

Figure D.1: Presentation of 4 different cost models for liquefaction of hydrogen.

E Storage Cost Model

Equation E.1 presents the cost model for calculation of storage costs. With the input values presented in E.1, calculations were made for a variety of plant capacities. From these calculations, a plot was created for an easier visual representation of the cost of storage. The cost model and the following calculations were based on findings from Reuß et al. [114].

$$Invest_{Total} = Invest_{Base} * \left(\frac{Capacity}{Invest_{Compare}} \right)^{Invest_{Scale}} \tag{E.1}$$

Capacity [kgH_2]	Capacity [kgLH_2]	Invest base [€]	Invest Compare	Invest Scale	Invest total (CAPEX) [M€]
790	1	25	1	0.95	0.015
7900	10	25	1	0.95	0.132
39500	50	25	1	0.95	0.611
59250	75	25	1	0.95	0.898
790000	100	25	1	0.95	1.181
118500	150	25	1	0.95	1.735
158000	200	25	1	0.95	2.281
237000	300	25	1	0.95	3.353

Table E.1: Storage cost calculations.

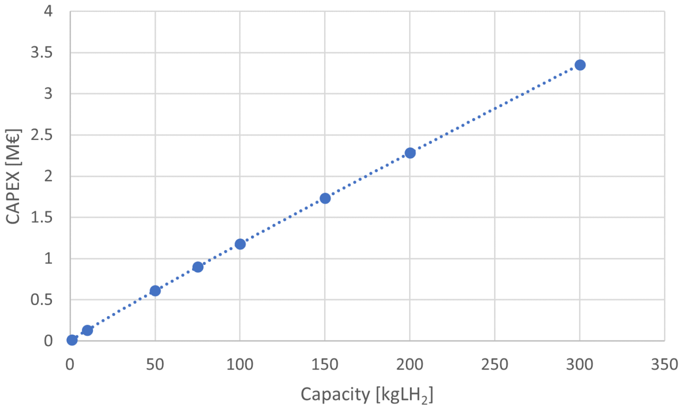


Figure E.1: Plot of storage cost from calculations based on data from Reuß et al. [114].

F CAPEX distribution in AWE and PEMWE Plants

(a) AWE

(b) PEMWE

Figure F.1: CAPEX distribution for 1 TWh system.

(a) AWE

(b) PEMWE

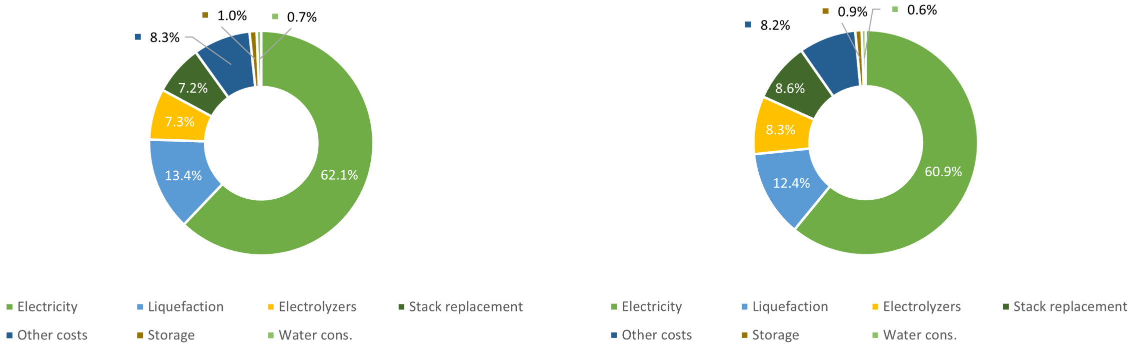
Figure F.2: CAPEX distribution for 3 TWh system.

(a) AWE

(b) PEMWE

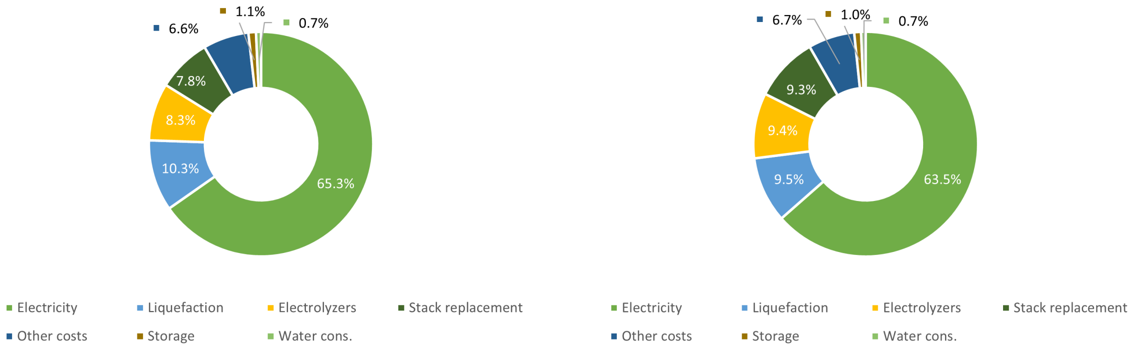
Figure F.3: CAPEX distribution for 5 TWh system.

G OPEX distribution in AWE and PEMWE Plants



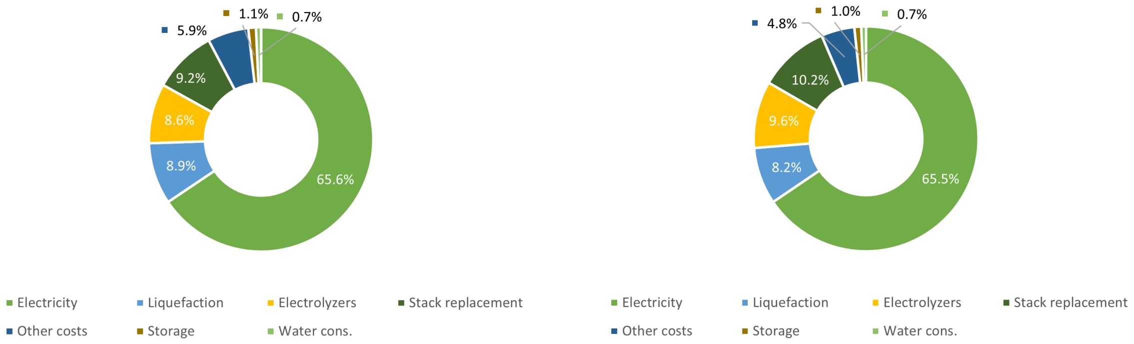
(a) AWE (b) PEMWE

Figure G.1: OPEX distribution for 1 TWh system.



(a) AWE (b) PEMWE

Figure G.2: OPEX distribution for 3 TWh system.



(a) AWE (b) PEMWE

Figure G.3: OPEX distribution for 5 TWh system.

H CAPEX vs OPEX Distribution

(a) AWE (b) PEMWE

Figure H.1: CAPEX vs OPEX distribution for 1 TWh system.

(a) AWE (b) PEMWE

Figure H.2: CAPEX vs OPEX distribution for 3 TWh system.

(a) AWE (b) PEMWE

Figure H.3: CAPEX vs OPEX distribution for 5 TWh system.

I MATLAB Script

Matlab script used to simulate the electrolyzer plant.

```
format long

        %Wind data
T = readtable('Kombinert_produksjon.xlsx','Range','F4836:F5201');%F4471/4836/5201
T = table2array(T);         % Converts the table to an array.
Time =  size(T,1);          % Determines how many days data were gathered from.
Wind_Prod_Orig = sum(T);    % MWh, Total original available wind energy.
T_Orig = T;                 % MWh, Original available wind energy.
T_GWh = T_Orig/1000;        % GWh, Original available wind energy.
        %Scaling
Projected_Capacity = 1000000;
% MWh, Desired available wind energy.
Scaling= (Projected_Capacity/Wind_Prod_Orig);
% Scaling factor between desired and original production
T = T.*Scaling;
%Scales available wind energy.
T = (T/24);
% MW/day, Converts from MWh to MW /day.
Wind_Cap_Orig = 255.6;
% MW, Original wind farm capacity.
Wind_Cap = Wind_Cap_Orig * Scaling;
% MW, wind farm capacity.

        %Inputs
Water_Price = 2/1000;
% Euro/litre, Buying price of water.
H2_Price = 10;
% Euro/kg, Selling price of liquid Hydrogen.
r = 0.08;
% Dec, Discount rate.
OPEX_Factor = 0.04;
% Dec, OPEX as percentage of CAPEX.
Op_Time = 20;
% Years, System Operational time.
P = 100;
% %, Cost percentage in modules and stack replacement.
E = 30;
% Euro/MWh, Buying price of electricity, LCOE equivalent.
VAT = 0.25;
% Dec, Value added tax in Norway.

        %Choose electrolysis cell
M400 = false;
M4000 = true;
A1000 = false;
A3880 = false;

        %Variables, put in end statement if in use.
%for P = 50:10:100;         % Loops cost reduction percentage.
%for E = 20:10:40;          % Loops price of electricity.

        %Electrolysis data
```

```
if M400 == true;        %M400
    PEM = true;
    % Checks if the electrolysis cell is PEM or ALK.
    Electrolyzer_Cap_MW = 2;
    % MW, Module capacity.
    Electrolyzer_CAPEX_kW = 924* P/100;
    % Electrolyzer System CAPEX Euro/kW
    Electrolyzer_CAPEX_EUR = 1848000* P/100;
    % Euro, Cost per module.
    Stack_Lifetime = 78750/24;
    % Days, Lifetime of module.
    Stack_Replacement_Cost = (1+VAT) *  Electrolyzer_Cap_MW* (P/100) * 428 /1000;
    % MEuro, Cost of replacing one module.
    Electrolyzer_Cap_H2 = 870 * (1/Electrolyzer_Cap_MW);
    % kg/(MW*day), Module H2 production capacity.
    Water_Consumption = 10;
    % l/kg, Water consumption over h2 production.
end

if M4000 == true;       %M4000
    PEM = true;
    % Checks if the electrolysis cell is PEM or ALK.
    Electrolyzer_Cap_MW = 20;
    % MW, Module capacity.
    Electrolyzer_CAPEX_kW = 512* P/100;
    % Euro/kW, Cost over capacity.
    Electrolyzer_CAPEX_EUR = 10240000* P/100;
    % Euro, Cost per module.
    Stack_Lifetime = 78750/24;
    % Days, Lifetime of module.
    Stack_Replacement_Cost = (1+VAT) * Electrolyzer_Cap_MW* (P/100) * 341 / 1000;
    % MEuro, Cost of replacing one module.
    Electrolyzer_Cap_H2 = 8450 * (1/Electrolyzer_Cap_MW);
    % kg/(MW*day), Module H2 production capacity.
    Water_Consumption = 10;
    % l/kg, Water consumption over h2 production.
end

if A1000 == true;       %A1000
    PEM = false;
    % Checks if the electrolysis cell is PEM or ALK.
    Electrolyzer_Cap_MW = 5;
    % MW, Module capacity.
    Electrolyzer_CAPEX_kW =  630* P/100;
    % Euro/kW, Cost over capacity.
    Electrolyzer_CAPEX_EUR = 2835000* P/B100;
    % Euro, Cost per module.
    Stack_Lifetime = 78750/24;
    % Days, Lifetime of module.
    Stack_Replacement_Cost = (1+VAT) *  Electrolyzer_Cap_MW * (P/100)* 340 / ...
        1000;
    % MEuro, Cost of replacing one module.
    Ramp_Up_Time = 2;
    % Hours, Ramp up time for module.
    Electrolyzer_Cap_H2 = 2050 * (1/Electrolyzer_Cap_MW);
    % kg/(MW*day), Module H2 production capacity.
    Water_Consumption = 10;
    % l/kg, Water consumption over h2 production.
```

```
end

if A3880 == true;       %A3880
    PEM = false;
    % Checks if the electrolysis cell is PEM or ALK.
    Electrolyzer_Cap_MW = 18;
    % MW, Module capacity.
    Electrolyzer_CAPEX_kW = 438* P/100;
    % Euro/kW, Cost over capacity.
    Electrolyzer_CAPEX_EUR = 7560000* P/100;
    % Euro, Cost per module.
    Stack_Lifetime = 78750/24;
    % Days, Lifetime of module.
    Stack_Replacement_Cost = (1+VAT) * Electrolyzer_Cap_MW* (P/100) * 396 / 1000;
    % MEuro, Cost of replacing one module.
    Ramp_Up_Time = 2;
    % Hours, Ramp up time for module.
    Electrolyzer_Cap_H2 = 8190 * (1/Electrolyzer_Cap_MW);
    % kg/(MW*day), Module H2 production capacity.
    Water_Consumption = 10;
    % l/kg, Water consumption over h2 production.
end

Max_wind_Orig = max(T);
% Reads the maximal wind production
Max_wind = floor(Max_wind_Orig/Electrolyzer_Cap_MW)*Electrolyzer_Cap_MW;
% Floors to highest utilizable wind energy.


    for i = 1:Time;
        % Day, Loops available wind energy.
        for n = Electrolyzer_Cap_MW:Electrolyzer_Cap_MW:Max_wind
            % MW, Loops for every module.

            %Hydrogen Production
        Wind_Available_in(n,i)= T(i,1);
        % MW, Available wind energy.
        Wind_Utilizable_in(n,i)= T(i,1);
        % MW, Available wind energy.
        Wind_Utilizable_in(n,i)= min(Wind_Utilizable_in(n,i),n);
        % MW, Limits available energy according to max electrolyzer capacity.
        Wind_Utilizable_in(n,i)=floor((Wind_Utilizable_in(n,i)  ...
            /Electrolyzer_Cap_MW)) * Electrolyzer_Cap_MW;
        % MW, rounds down available energy to highest production capacity.
        H2_Production_in(n,i) = Wind_Utilizable_in(n,i) * Electrolyzer_Cap_H2;
        % kg, Hydrogen production this day.
        Wind_Energy_Loss_in(n,i) =  Wind_Available_in(n,i) - ...
            Wind_Utilizable_in(n,i);
        % MW, Lost wind energy due to module capacity.

            %Factors
        Load_Factor_in(n,i) = H2_Production_in(n,i)/(n*Electrolyzer_Cap_H2);
        % Load factor per dag ved ulike kapasiteter
        Module_Amount_in(n,i) = n / Electrolyzer_Cap_MW;
        % Number of modules.

            %Costs
        CAPEX_Module_in(n,i) = (Electrolyzer_CAPEX_kW*n/1000)*(1+VAT);
```

```
        % MEuro, CAPEX due to modules
        CAPEX_Liquefaction_in(n,i) = ...
            7.37*((Electrolyzer_Cap_H2*n/1000)^0.6667)*(1+VAT);
        % MEuro, CAPEX due to liquefaction.
        Other_Cost_Factor_in(n,i) = (1/100)*51.483*n^-0.104;
        % Dec, Other cost factor.


        end
    end

                                %Simplifications
    %Removes all rows with zeroes, due to loop only iterating every ...
        'Electrolyzer_Cap_MW'
Wind_Available = Wind_Available_in(any(Wind_Available_in,2),:);
Wind_Utilizable = Wind_Utilizable_in(any(Wind_Utilizable_in,2),:);
H2_Production = H2_Production_in(any(H2_Production_in,2),:);
CAPEX_Module = CAPEX_Module_in(any(CAPEX_Module_in,2),:);
Wind_Energy_Loss = Wind_Energy_Loss_in(any(Wind_Energy_Loss_in,2),:);
Load_Factor_daily = Load_Factor_in(any(Load_Factor_in,2),:);
Module_Amount = Module_Amount_in(any(Module_Amount_in,2),:);
CAPEX_Liquefaction = CAPEX_Liquefaction_in(any(CAPEX_Liquefaction_in,2),:);
Other_Cost_Factor = Other_Cost_Factor_in(any(Other_Cost_Factor_in,2),:);

    % Removes duplicate columns, due to only relying on n in loop.
CAPEX_Liquefaction = CAPEX_Liquefaction(:,[1]);
Other_Cost_Factor = Other_Cost_Factor(:,[1]);
CAPEX_Module = CAPEX_Module(:,[1]);
Module_Amount = Module_Amount(:,[1]);


    %Totals
Wind_Energy_Loss_Tot = sum(Wind_Energy_Loss,2)*365/Time;
% MW/year, Total energy loss per year.
Load_Factor = sum(Load_Factor_daily,2)/Time;
% Dec, Load factor at different module amounts.
Stack_Replacement_Time = (Stack_Lifetime./Load_Factor)/365;
% Years, Replacement time of each stack.
H2_Production_Tot = sum(H2_Production,2)*365/Time;
% kg/year, Total hydrogen production each year
H2_Production_Discounted = sum(H2_Production,2)*365/Time;
% kg/year, Total hydrogen production each year with discount rate. For use in ...
    LCOH calculations.
Max_Module_Amount =  size(Module_Amount,1);
% Counts number of modules.

    %Adjustment in H2 production due to ramp up time in alkaline modules.
if PEM==false       % Checks if the module is alkaline.
    z = zeros(Max_Module_Amount,1);
    % Creates an array consisting of zeroes.
    Ramp_From = [ z, Wind_Utilizable];
    % MW, Adds zeroes to the front of the array.
    Ramp_To = [ Wind_Utilizable, z];
    % MW, Adds zeroes to the end of the array.
    Ramp_Up_Diff = (Ramp_From - Ramp_To);
    % MW, Determines the daily difference in available capacity.
    RAM =-1.*( Ramp_Up_Diff./ Electrolyzer_Cap_MW);
    % Amount of modules that need to be ramped up
```

```
    RAM(RAM<0) = 0;
    % Sets negative values to 0.
    RAM_Tot = sum(RAM,2) - Module_Amount;
    % Total amount of modules inn need of ramp up over period.
    RAM_MW_Loss = RAM_Tot * Electrolyzer_Cap_MW * 2/24;
    % MW, Loss of capacity due to ramp up.
    RAM_H2_Loss = RAM_MW_Loss .* Electrolyzer_Cap_H2;
    % kg/year, Loss of H2 production.
    RAM_Percentage_Loss = RAM_H2_Loss ./ H2_Production_Discounted;
    % Dec, Loss of H2 production.
    H2_Production_Discounted = H2_Production_Discounted - RAM_H2_Loss;
    % kg/year, New total H2 production.
    H2_Production_Tot = H2_Production_Discounted - RAM_H2_Loss;
    % kg/year, New total H2 production.

end

        %Storage
Storage_Required = ...
    (Module_Amount*Electrolyzer_Cap_MW*10*Electrolyzer_Cap_H2)./790;
% kgLH2, Storage capacity needed to store day days worth.

        %CAPEX
CAPEX_Storage =  0.0149*((Storage_Required).^0.95).*(1+VAT);
% MEuro, CAPEX of storage.
CAPEX_Equipment = Other_Cost_Factor.*(CAPEX_Storage + CAPEX_Module + ...
    CAPEX_Liquefaction);
% MEuro, CAPEX of equipment etc.
CAPEX_Total = (CAPEX_Equipment + CAPEX_Storage + CAPEX_Module + ...
    CAPEX_Liquefaction) * 1000000;
% Euro, CAPEX of entire system.

        %Discount Factor
for k = 1:Op_Time;
    % Year, Loops for the lifetime of the plant.
     Discount_Factor_Yearly(k) = 1/(1+r)^k;
     % Dec, calculates cumulative discount factor.
end
Discount_Factor_Average = sum(Discount_Factor_Yearly)/Op_Time;
% Dec, Average discount factor.



        %OPEX
OPEX_Water = (Water_Consumption .* H2_Production_Discounted * Water_Price);
% Euro/year, OPEX of water.
OPEX_Water_avg = OPEX_Water * Discount_Factor_Average;
OPEX_Module = OPEX_Factor .* CAPEX_Module * 1000000;
% Euro/year, OPEX of modules.
OPEX_Module_avg = OPEX_Module * Discount_Factor_Average;
OPEX_Module_avg_tot = OPEX_Module_avg*20;
OPEX_Equipment = OPEX_Factor .* CAPEX_Equipment * 1000000;
% Euro/year, OPEX of equipment.
OPEX_Equipment_avg = OPEX_Equipment * Discount_Factor_Average;
OPEX_Storage = OPEX_Factor .* CAPEX_Storage * 1000000;
% Euro/year, OPEX of storage.
OPEX_Storage_avg = OPEX_Storage * Discount_Factor_Average;
OPEX_Liquefaction = OPEX_Factor .* CAPEX_Liquefaction * 1000000;
```

```
% Euro/year, OPEX of liquefaction.
OPEX_Liquefaction_avg = OPEX_Liquefaction * Discount_Factor_Average;
OPEX_Stack_Replacement = (Module_Amount .* Stack_Replacement_Cost ./ ...
    Stack_Replacement_Time) * 1000000;
% Euro/year, OPEX of stack replacement.
OPEX_Stack_Replacement_avg = OPEX_Stack_Replacement * Discount_Factor_Average;
OPEX_Electricity = sum(Wind_Available,2)*24*E*365/Time;
% Euro/year, OPEX of electricity.
OPEX_Electricity_avg = sum(OPEX_Electricity,2) * Discount_Factor_Average;
OPEX_Electricity_no_pl = sum(Wind_Utilizable,2)*24*E*365/Time;
% Euro/year, OPEX of electricity w/o wind energy loss.

OPEX_Total_in = (OPEX_Stack_Replacement + OPEX_Liquefaction + OPEX_Storage + ...
    OPEX_Equipment + OPEX_Module + OPEX_Water + OPEX_Electricity)  ;
% Euro/Year, Total OPEX pre discount.
OPEX_Total_in_test = OPEX_Total_in * Discount_Factor_Average;
OPEX_Total_in_avg = (OPEX_Stack_Replacement_avg + OPEX_Liquefaction_avg + ...
    OPEX_Storage_avg + OPEX_Equipment_avg +  OPEX_Module_avg + OPEX_Water_avg ...
    + OPEX_Electricity_avg);
OPEX_Yearly_in =  OPEX_Total_in_avg * Op_Time;

        % calculating yearly OPEX, taking the discount factor into account.
for k = 1:Op_Time;
    % Year, Loops for the lifetime of the plant.
    for j = 1:Max_Module_Amount;
        % Loops for every amount of modules.
           OPEX_Yearly(j,k) = OPEX_Total_in(j)/((1+r)^k);
           % Euro, OPEX each year.
           OPEX_Electricity(j,k) = OPEX_Electricity(j)/((1+r)^k);
           % Euro, OPEX of electricity each year.
           OPEX_Electricity_no_pl(j,k) = OPEX_Electricity_no_pl(j)/((1+r)^k);
           % Euro, OPEX of electricity each year without power loss.
    end
end
OPEX_Total = sum(OPEX_Yearly,2);
% Euro, Total system OPEX.
OPEX_Total_avg = OPEX_Total/Op_Time;
OPEX_Electricity_diff = OPEX_Electricity-OPEX_Electricity_no_pl;

        %Results
Electricity_Share = sum(OPEX_Electricity,2) ./ OPEX_Total;
% Dec, Share of electricity costs in OPEX.
Lifetime_Costs = OPEX_Total + CAPEX_Total ;
% Euro, Total lifetime costs.
Lifetime_Costs_No_D = OPEX_Total_in .* Op_Time + CAPEX_Total ;
% Euro, Total lifetime costs w/o discount rate.
Wind_Energy_Loss_Cost = (24 * E .* Wind_Energy_Loss_Tot)*Op_Time* ...
    Discount_Factor_Average;
% Euro, Total cost of unutilized wind energy.
Lifetime_Costs_No_Power_Loss = (OPEX_Total + CAPEX_Total) - ...
    Wind_Energy_Loss_Cost ;
% Euro, Total lifetime costs w/o loss of wind energy.
H2_Production_Discounted = sum(H2_Production,2)*365/Time*Discount_Factor_Average;
% kg/year, H2 Production.
LCOH =  Lifetime_Costs ./ (H2_Production_Discounted .* Op_Time);
% Euro, LCOH.
LCOH_No_D =  Lifetime_Costs_No_D ./ (sum(H2_Production,2)*365/Time .* Op_Time);
% Euro, LCOH w/o discount rate.
```

```
LCOH_No_Power_Loss = Lifetime_Costs_No_Power_Loss ./ ...
    (H2_Production_Discounted .* Op_Time);
% Euro, LCOH w/o loss of wind energy.
Cost_Distribution_OPEX = (OPEX_Total) ./ Lifetime_Costs;
% Dec, OPEX as fraction of total costs.

        %Calculating NPV, discounted payback period and ROI.
        %_pl means wind energy loss is acocunted for.
for h= 1:100;
    % Loops for H2 selling price between 1 and 10 Euro.
    H2_Price_pl = h;
    % Defines h as H2 selling price.
    Income_H2_pl = H2_Production_Discounted * H2_Price_pl*0.1;
    % Euro, Total income due to selling H2.
    Income_Yearly_pl = Income_H2_pl - OPEX_Yearly;
    % Euro, Cash flow.
    Income_Cumulative_pl= cumsum(Income_Yearly_pl,2);
    % Euro, Sum of all cash flows.
    Payback_pl = Income_Cumulative_pl-CAPEX_Total;
    % Euro, Sum of all cash flows, with initial CAPEX included
    for i = 1:Max_Module_Amount;
        % Loops every module.
        for j = 1:Op_Time;
            % Loops for lifetime of plant.
                NPV(h,i) = Income_Cumulative_pl(i,20)-CAPEX_Total(i);
                % Euro, Net Present Value.
                if NPV(h,i) < 0;
                    % Checks if NPV is negative.
                    NPV(h,i) = 0;
                    % Defines every negative NPV as 0.
                end
            if Payback_pl(i,j) > 0;
                % Checks if the value is larger than 0.
                Payback_Period(h,i) = (j)-(Payback_pl(i,j) / ...
                    Income_Yearly_pl(i,j));
                % Years, defines discounted payback period.
            else
                Payback_Period(h,i)=0;
                % Negative values is set to 0.
                continue
            end
        end
    end
end

for h= 1:100;
    H2_Price_pl_no_pl = h;
    Income_H2_pl_no_pl = H2_Production_Discounted * H2_Price_pl_no_pl*0.1;
    % Euro/Year
    Income_Yearly_pl_no_pl = Income_H2_pl_no_pl - ...
        (OPEX_Yearly-OPEX_Electricity_diff);
    Income_Cumulative_pl_no_pl= cumsum(Income_Yearly_pl_no_pl,2);
    Payback_pl_no_pl = Income_Cumulative_pl_no_pl-CAPEX_Total;
    for i = 1:Max_Module_Amount;
        for j = 1:Op_Time;
                NPV_no_pl(h,i) = Income_Cumulative_pl_no_pl(i,20)-CAPEX_Total(i);
                % Net Present Value, Op_Time = Max
                if NPV_no_pl(h,i) < 0;
```

```
                    NPV_no_pl(h,i) = 0;
                end
            if Payback_pl_no_pl(i,j) > 0;
                Payback_Period_no_pl(h,i) = ...
                    (j)-(Payback_pl_no_pl(i,j)/Income_Yearly_pl_no_pl(i,j));
            else
                Payback_Period_no_pl(h,i)=0;
                continue
            end
        end
    end
end

        %Additional LCOH calculations, for use when P and E are set to loop.
    for u= 1:Max_Module_Amount;    % Loops for every module.
    LCOH_E_in(E,u) = LCOH(u);   % Defines LCOH at different electricity prices
    end

    for u= 1:Max_Module_Amount; % Loops for every module.
    LCOH_P_in(P,u) = LCOH(u);       % Defines LCOH at different module CAPEX.
    end
%end                                % Ends loop for calculating E or P.


Payback_Period_no_pl = Payback_Period_no_pl'; %Years
NPV_no_pl = NPV_no_pl'; %Euro
ROI_no_pl = ((NPV_no_pl)./CAPEX_Total)*100;


Payback_Period = Payback_Period';
% Years, Flips discounted payback period for easier plotting
NPV = NPV';
% Euro, Flips NPV for easier plotting.
ROI = ((NPV)./CAPEX_Total)*100;
% Dec, Defines


    %Plotting
Wind_Utilizable_Total = sum(Wind_Utilizable,2);
Wind_Available_Total = sum(Wind_Available,2);
Load_Factor_EL = Wind_Utilizable_Total ./ Wind_Available_Total;
% Defines load factor of wind energy usage.
    %Enable if looping for E or P
%LCOH_E = LCOH_E_in(any(LCOH_E_in,2),:);
%LCOH_E = LCOH_E';

%LCOH_P = LCOH_P_in(any(LCOH_P_in,2),:);
%LCOH_P = LCOH_P';
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