Offshore wind power and hydrogen for oil and gas platform electrification

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Now that I am about to enter my career as an engineer, I reflect on five years of education filled with lots of work and countless late evenings. However, I also look back at five of the most interesting years of my life. During these years I have gained valuable knowledge, and I hope that I now will be able to use my knowledge for the greater good.

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Abstract

Electrification of oil and gas platforms is a subject which has been frequently mentioned as a way of cutting Norwegian climate emissions. This thesis has investigated possibilities for using offshore wind power and hydrogen to power an oil platform. Calculations have been made to find the necessary capacity for this proposed energy system. Furthermore, calculations have been made to investigate the effects of varying efficiency values for the hydrogen system, varying wind park losses, and how different wind power capacity factors affect the results. A techno-economic analysis was also performed in addition to investigating if a natural gas turbine could be used for peak power shaving.

The results indicate that it is possible to power a platform using offshore wind power and hydrogen in an off-grid system. It is however considered not to be profitable as well as being energetically inefficient. Calculations showed that variations in efficiency, wind park losses and capacity factors have a severe effect on the results. By using a natural gas turbine for peak power shaving the hydrogen capacity could be reduced significantly.

Future work should look at import and export of hydrogen to the mainland to reduce hydrogen capacity and increase income, as well as investigate if having several platforms connected to the system would improve the feasibility.

Abbreviations

AFC	Alkaline fuel cell
CAPEX	Capital expenditure
CCS	Carbon capture and storage
CCUS	Carbon capture, utilisation, and storage
EU ETS	European Union Emissions Trade System
GWh	Gigawatt hour
HVDC	High voltage direct current
ICE	Internal combustion engine
IPCC	Intergovernmental Panel on Climate Change
kWh	Kilowatt hour
LCOE	Levelized cost of energy
LCOH	Levelized cost of hydrogen
LOHC	Liquid organic hydrogen carrier
MSR	Market stability reserve
MW	Megawatt
NCF	Net cash flow
NOK	Norwegian Kroner
NORA 3	Norwegian hindcast archive
NPV	Net present value
OPEX	Operational expenditure
PEM	Proton exchange membrane
PEMFC	Proton exchange membrane fuel cell
SOFC	Solid oxide fuel cell
STP	Standard temperature and pressure
TWh	Terawatt hour
UHS	Underground hydrogen storage

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Chapter 1

Introduction

1.1 Motivation

According to the Intergovernmental Panel on Climate Change (IPCC) the period 2010 —2019 was the decade with the highest greenhouse gas emissions of all time [1]. This is despite there being a major focus on reducing climate emissions to stop climate change. The message from the IPCC is clear; the world community must act immediately for it to be able to reach the target of maximum 1.5 °C temperature increase.

In Norway, hydro power is the main source of electricity generation and according to Statistics Norway hydro constitutes 91 % of the total [2]. However, since Norway discovered oil at Ekofisk in 1969, the country has made billions of NOK from oil and gas production. The Norwegian oil and gas production takes place at platforms located offshore. Even though some of these platforms are electrified with cables from shore, most of them use fossil fuels for electricity generation. Natural gas or oil is used in turbines or combustion engines to run generators that produce electricity. This use of fossil fuels, together with the major energy demand on these platforms, lead to large emissions of climate gasses. Since 1990 the climate gas emissions from the oil and gas production in Norway has increased by 61 % [3]. In fact, the Norwegian oil and gas production contributes to 27 % of Norway's total climate emissions. This makes the petroleum industry the second largest emitter of climate gases in the country, only behind transportation [4].

1.2 Problem Statement

If the emissions from the petroleum sector are to be reduced or removed, new solutions must be implemented for electricity production offshore. One solution is, as mentioned, electrification from shore; however, this has resulted in fears about rising electricity prices due to the platforms large demands [5]. Due to this it is of interest to investigate other solutions for platform electrification using renewable power. One possible solution could be to use wind power to produce electricity. However, a known challenge for renewable energy is intermittency. A wind farm will only produce power when there is wind, and there needs to be a certain amount of wind if the wind farm is to produce enough electricity. This means that some sort of energy storage is needed, which can be utilised in periods where there is little or no wind. A solution could be to use hydrogen which can be produced from surplus power from the wind farm, and then stored for long periods of time.

1.3 Objectives

This thesis will use wind data from the Norwegian hindcast archive (NORA3) together with consumption data from an oil platform, which is in operation as this thesis is written. The proposed energy system will use wind power to produce electricity and power the platform, and will in periods of overproduction use the surplus to produce green hydrogen. This hydrogen will be stored and then used in periods where there is little or no wind to provide backup power for the platform. The objectives of this thesis will be to investigate:

1. if it is possible to power oil and gas platforms with wind power and hydrogen, and to find out what capacity for both the wind farm and hydrogen system is needed to do so.
2. how different efficiency values as well as wind park losses affect the capacity requirements.
3. what the total investment cost and net present value is for the power system.
4. if it is possible to utilise a hybrid backup system to reduce size and cost of the hydrogen system.
5. how different locations, with different capacity factors at the wind park, affect the results and feasibility of such a project.

1.4 Contribution

There has been little research on platform electrification using wind power and hydrogen. This thesis will investigate the points listed above regarding this solution and try to give an indication if this is a feasible way of electrifying the oil and gas sector. The results of this thesis could be a starting point for future research regarding platform electrification using wind power and hydrogen. Furthermore, it could illustrate technology gaps and potential bottlenecks.

1.5 Thesis outline

The thesis will start by showcasing related research projects, as well as mentioning real life projects which are relevant. After this part the thesis moves on to explain relevant theory regarding the wind farm and the hydrogen system. Some relevant laws and regulations will also be explained briefly in this part. Explanations of assumptions made, and the different calculations performed will be presented in the methods chapter. The results chapter will follow the same structure as the methods chapter and present the calculated results . In the discussion chapter, the key findings from the results will be interpreted as well as highlighting limitations of the research performed. The discussion will also include suggestions of implementations and future work. Conclusions will be drawn in the final chapter with the interpretations from the discussion chapter considered.

Chapter 2

Background and theory

This thesis will as mentioned look at electrification of oil and gas platforms using offshore wind power and hydrogen. In such a project there are several vital components needed, where there are several different technologies to choose from for each component. The choice of components will influence both the size and cost of the project. Because of this it is important to look at several technologies, and then choose the most appropriate. In this chapter of the thesis, the different components will be looked at, and the foundations for making choices on technology will be laid out. Moreover, previous work performed on similar subjects, both from the author, as well as others, will be presented at the start of the chapter. Lastly, rules and regulations affecting the project will be investigated.

2.1 Previous work

As highlighted in the introduction, little research has been published on electrification of platforms using wind power and hydrogen. At the time of writing, to the best of the authors knowledge, there are no other publications released on this particular topic apart from the authors own bachelor thesis [6]. There are however several publications on platform electrification using wind power, as well as publications on offshore green hydrogen production from wind power. When it comes to electrification of the oil and gas industry, both Hywind Tampen and Deep Purple are relevant ongoing projects which will be discussed later. In this section of the thesis both the work done regarding the bachelor thesis, as well as related research projects will be explained.

2.1.1 Bachelor thesis

In 2020 a bachelor thesis on a similar subject was written by the author of this thesis. The goal of the bachelor thesis was to highlight the cost drivers for electrification of platforms using wind and hydrogen or ammonia. Furthermore, the thesis was meant to uncover gaps in technology regarding using such a system. Calculations for necessary capacity and cost for both a hydrogen and an ammonia system were made. The hydrogen system consisted of electrolysers for hydrogen production, subsea storage tanks, fuel cells for electricity generation and an external platform for the electrolysers and fuel cells. For the ammonia system the hydrogen production was the same, but there was also a Haber-Bosch process involved for converting hydrogen to ammonia. The ammonia was supposed to be stored subsea in special bags at a depth where the natural surrounding pressure would liquefy the ammonia. For electricity generation an internal combustion engine (ICE), supposed to run on 100 % ammonia, was utilised. This ICE further drove a generator which provided the platform with electricity. Due to the low efficiency of the ammonia system, the hydrogen system were the preferred solution. The Haber-Bosch process led to increased efficiency losses in the production phase, and the ammonia ICE provided a lower efficiency than the hydrogen fuel cells. With a lower efficiency, both the necessary capacity and cost of the components increase. At the time of writing, the main cost driver was found to be the wind park. The use of the ammonia system would lead to an increased demand of installed power in the wind park, which would drastically increase cost. However, the ammonia system showed the lowest investment cost and the highest net present value (NPV). It was however assumed that the components needed for the hydrogen solution was closer to being commercialized. The thesis also highlighted problems regarding data, and further work which was necessary. A lack of real consumption data from a platform led to increased inaccuracy. Furthermore, the low quality wind data used also proved to be a problem and further work would need to utilise higher quality data. Lastly the thesis mentioned the need of comparing different locations to understand how different wind conditions would change the outcome [6].

2.1.2 Related research

As mentioned, there are several research projects looking at offshore hydrogen production from wind power, and also projects looking at electrification of oil and gas platforms. Calado [7] Looks at hydrogen production from offshore wind and covers a wide range of interest areas including integration of hydrogen in wind power systems, the different properties of hydrogen components, as well as an analysis of two different systems for production of hydrogen from offshore wind. The article investigates both an offshore and an onshore electrolyser scenario. The offshore solution uses an offshore wind park with a platform containing electrolysers and the storage being onshore. The second solution uses an offshore wind farm, as well as an offshore transformer to send the electricity to shore where the electrolysers and storage are placed. Lastly the article summarises the levelized cost of hydrogen (LCOH) from several different studies using a variation of electricity sources. The result is an interval for the LCOH for all the electricity sources which include grid, solar photovoltaic, concentrated solar power, onshore wind, and offshore wind. As expected, the offshore wind scenario is the most expensive option, mainly due to the cost of this source of electricity. The LCOH increases from around 2.5 Euro/kg to 9.17 Euro/kg when going from electricity from grid to offshore wind power. For the scenario with onshore wind power the LCOH was 4.33 Euro/kg.

Marvik [8] looks at using offshore wind integration for electrification of offshore petroleum installations. The article starts by stressing the need for zero emission power at oil and gas platforms given their large climate emissions. Further, the paper looks at a case with a cluster of oil and gas installations 280 km southwest of the Norwegian coast. There are 4 oil and gas platforms which are connected to the grid using a high voltage direct current (HVDC) link. Combined, the four platforms have a constant power demand of 142 MW. Further, the paper then looks at four different configurations of wind power use combined with the grid connection. The first configuration features zero wind power with all power coming from the HVDC cable. The second configuration looks at a 140 MW wind park for load balance when all the wind turbines produce at full power. The third configuration utilises two 140 MW wind parks which enables the system to export power to the grid when there are good wind conditions. The fourth configuration also utilises two wind farms of 140 MW. However, the production level is low, and the wind farms only produce 95.2 MW which is 34 % of the nominal power. This means that there is no surplus power for export to shore. Further, the article looks at use of reactive power at the platforms and suggest ways of dealing with the necessary capacity as well as keeping costs and size down.

Grainger [9] looks at different methods for reducing carbon emissions from the oil and gas production offshore. The article highlights the low percentage of emissions the production of hydrocarbons contributes compared to the total life cycle of hydrocarbons. However, as explained in the article, taxes, and fees on carbon emissions together with national decarbonisation goals are reasons for eliminating the emissions. The article then presents several different alternatives for reduction of the CO2 emissions. The alternatives include:

- Lowering the energy demand on the platforms
- Increasing the efficiency of energy conversion
- Carbon capture and storage (CCS)
- Low carbon power production

For the alternative with low carbon power production one of the solutions highlighted is offshore wind power. As also mentioned in chapter 1 the intermittency of the wind power ensures that the system needs a backup power solution. The article talks about using natural gas turbines for generating power when there is little or no wind. This further leads to the need for an advanced control system with models using weather forecasting. Another example for power production mentioned is receiving hydrogen from shore. The article points to the large power demand on platforms as a reason why using ships for hydrogen delivery is unpractical. However, using pipelines for hydrogen delivery is mentioned as a possible alternative. Overall, the article concludes that picking a decarbonisation solution for a platform depends on several factors, and that there is not one solution for all platforms.

In addition to research projects there are as mentioned real life projects being both developed and executed:

Hywind Tampen

Hywind Tampen is an Equinor project designed to drastically reduce climate emissions from Snorre A, Snorre B, Gullfaks A, Gullfaks B and Gullfaks C. Upon completion Hywind Tampen will be the largest floating wind park in the world with 88 MW installed capacity. The wind park will consist of 11, 8 megawatt floating wind turbines. The electricity generated by the wind turbines will be delivered directly to the oil platforms with no connection to shore. It is expected that the wind turbines will cover around 30—35% of the total energy consumption from the 5 platforms. The remaining power will be supplied by the gas turbines which today produces 100% of the energy needed. The reductions in climate emissions from this project is estimated to be around 200,000 tonnes of CO2 and 1000 tonnes of NOX every year [10]. Enova have supported the Hywind Tampen project with 2.3 billion NOK [11].

Deep Purple

The Deep Purple project is a project coming from TechnipFMC which intends to use surplus energy from wind power to produce hydrogen and is similar to the project in this thesis. The system is intended to be able to supply a range of systems, oil and gas platforms included, with emission free electricity. Hydrogen is intended to be produced in electrolysers before it is stored subsea. When there is a need of energy, hydrogen fuel cells will be used to produce electricity from the hydrogen [12].

PosHYdon

A project called the PosHYdon project is looking at hydrogen production from an oil platform, using wind energy. The platform used for the project is located 13 km outside the coast of the Netherlands. Using pipelines, the hydrogen produced is intended to be mixed with natural gas and transported to shore. PosHYdon will provide valuable knowledge of how the components used in hydrogen production is affected by the rough offshore conditions [13]. This knowledge would be essential if a project like the one in this thesis is to be executed.

2.2 Oil platform power consumption

When calculating the needed capacity for the wind park and hydrogen system it is important to know how much power the platform, which is to be electrified, uses. The data for consumption will be used together with the produced power from the wind park to determine if there is a surplus or shortage of energy. In this thesis, hourly data for power consumption over a period of 13 months have been gathered from a platform which is not further identified. The platform in question has a maximum power consumption of 34 MW with the power consumption mostly constant. The platform currently uses natural gas to produce power. Gas is burned in a gas turbine which further runs a generator which produce electricity. The power is used for gas compression, water injection, stabilised crude oil export, re-compression system, seawater lift pumps and the base load.

2.3 Wind power

Wind power is one of the fastest growing sources of renewable energy. The technology works by converting kinetic energy in the wind to electrical energy. When wind hits the blades of the wind turbine, the blades generate lift, which makes the blades spin around. This drives an axle which further drives a generator which creates electricity. How much energy is captured by the wind turbine relative to the amount of energy in the wind is dependent on the efficiency of the wind turbine. The efficiency of a wind turbine will vary between turbines, with 59.3 % as the theoretical maximum. This is known as Betz Limit and is named after the German physicist Albert Betz. However, most wind turbines only reach efficiencies of up to 45% [14].

When planning a wind energy project, it is important to know how much wind resources are available. It is possible to calculate the available wind power per unit time with the given formula, where ρ is the air density, u is the wind speed and A is the area of the wind turbine blades [14]:

$$P = \frac{1}{2}\rho u^3 A \tag{2.1}$$

To determine the available power from a wind turbine, and not the wind, the efficiency of the wind turbine needs to be included [14]:

$$P = \frac{1}{2}\rho u^3 A\eta \tag{2.2}$$

The power formula also illustrates one of the reasons that wind turbines are getting bigger and bigger. The area of the wind turbine is calculated as:

$$A = \pi r^2 \tag{2.3}$$

Since the radius in the formula is in the power of 2 there is a quadratic growth when increasing radius. This further means that a small increase in radius will have a big impact on the energy available. The power formula can also be used to calculate power per area when divided by A [14]:

$$\frac{P}{A} = \frac{1}{2}\rho u^3 \tag{2.4}$$

This formula can be used to compare different areas regarding power production. By using the average wind speed of an area, it is possible to calculate the average power per area available in the wind. Table 2.1 compares different values of average power per area.

$\overline{P}/A<100W/m^2$	Low
$\overline{P}/A \approx 400W/m^2$	Good
$\overline{P}/A>700W/m^2$	Great

Table 2.1: Power per area. Adapted from [14]

Figure 2.1 illustrates the swept area for a wind turbine as well as the radius for the swept area.

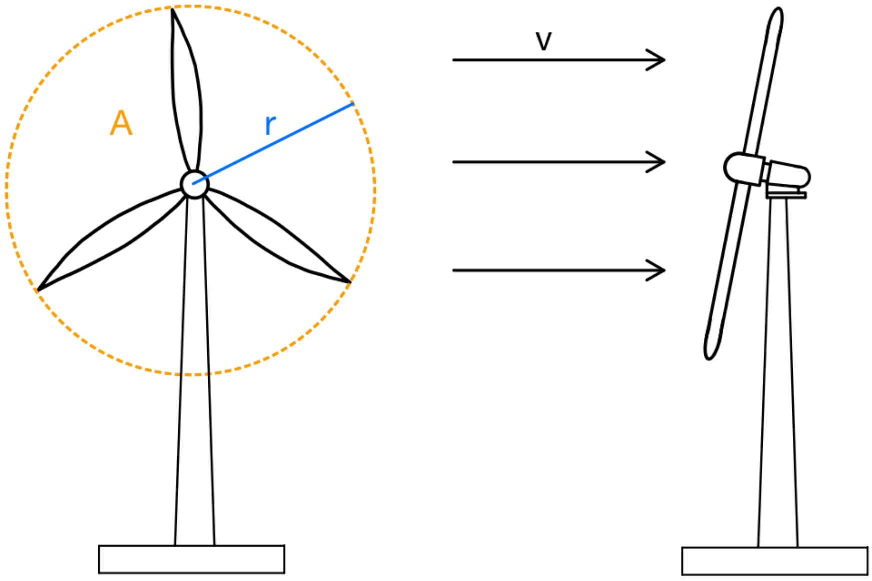

Figure 2.1: Swept area of a wind turbine.

As mentioned, the wind power industry is growing fast, and a part of this growth comes from the offshore wind industry. From 2010 to 2018 the yearly capacity additions globally for offshore wind power increased from around 1 GW to 4.3 GW. In 2010 there were 3 GW of installed capacity and in 2018 this had increased to 23 GW [15].

In Norway there are currently 64 wind parks with a total capacity of 4650 MW [16]. All the Norwegian wind parks are located onshore. However, there are currently plans to build offshore wind parks at 2 locations in the North Sea with Sørlige Nordsjø II and Utsira Nord as the chosen locations. Hywind Tampen will as mentioned also be located offshore and is expected to be completed soon. Onshore wind farms are facing large protests, and a survey from the Norwegian citizen panel showed that only 43 % of the Norwegian population wants more wind power onshore. On the other hand, 76 % of the population agrees to build more wind power offshore [17].

Offshore wind power has some advantages over onshore wind power, with better wind conditions as one of them. However, there are also several drawbacks with placing wind turbines offshore. One of these drawbacks is the increased cost. In Norway, land based wind power is currently the cheapest energy source to build according to the levelized cost of energy (LCOE). This is illustrated in Table 2.2 which showcases the LCOE for different methods for power production in Norway in 2021. The LCOE is a value for the cost of energy over the lifetime of a project [18]. This means that the LCOE represents the necessary price for electricity sale if a project is to be profitable. It is therefore beneficial to have the LCOE as low as possible.

Technology for power production	LCOE in 2021 [NOK/kWh]
Hydro (< 10 MW)	0.35
Hydro (> 10 MW)	0.39
Land based wind power	0.30
Bottom-fixed wind power	0.69
Floating wind power	1.17
Solar at house roofs	1.01
Solar at big flat roofs	0.68
Ground mounted solar plant	0.49
Coal	0.69
Gas-fired combined cycle power plant	0.61
Nuclear	0.66

Table 2.2: LCOE of power production methods in Norway in 2021. Numbers from [18]

As shown in Figure 2.2 the LCOE in 2021 is, according to The Norwegian water resources and energy directorate (NVE), 0.30 NOK/kWh. For offshore wind power however, the LCOE is 0.69 NOK/kWh and 1.17 NOK/kWh for bottom-fixed and floating, respectively. Land based wind power is regarded as a much more mature technology than offshore wind. This suggests that with future development of offshore wind and increased maturity, the prices will drop. According to NVE the LCOE for onshore wind will drop to 0.22 NOK/kWh in 2030, which corresponds to a 26.7 % decrease. For offshore wind power the LCOE will drop to 0.51 NOK/kWh and 0.68 NOK/kWh in 2030 for bottom-fixed and floating respectively. This further means a reduction of 26 % and 41.9 % over the period from 2021 to 2030 [18]. This thesis will look at projects which utilises floating wind turbines and will use CAPEX numbers presented as NOK per MW of installed capacity. In 2019 Multiconsult made a report for Equinor where they looked at societal effects of the Hywind Tampen project. Multiconsult made an estimate of 57 MNOK/MW of installed capacity for a floating wind park in 2020, which will drop to 25 MNOK/MW in 2030 [19].

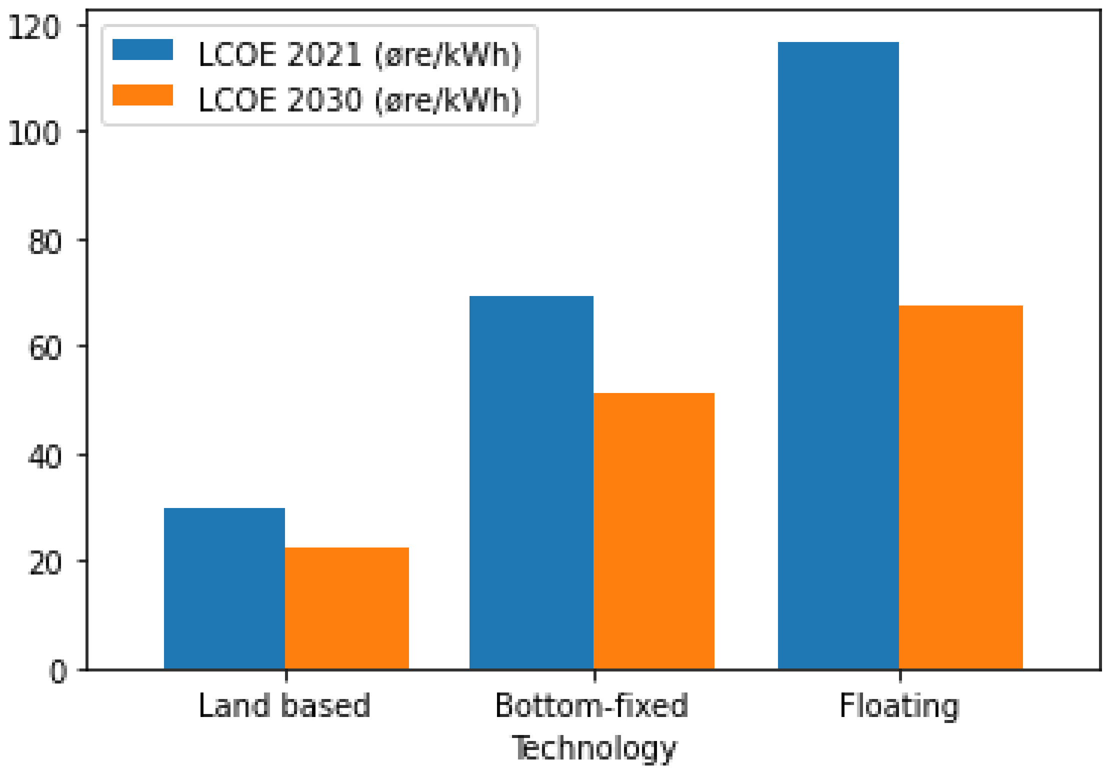

Figure 2.2: LCOE for different wind power technologies in 2020 and 2030. Data gathered from [18].

To get a better understanding of the calculations and results in this thesis it is important to understand the meaning of some key values for wind turbines. Some of the key values are cut-in speed, cut-out speed, rated power, capacity factor, wake effect and availability losses.

The cut-in speed is the wind speed which the wind turbine starts producing power. When the wind speed is lower than the cut-in speed, no power is produced, and the blades are standing still. Normally the cut-in speed for wind turbines is around 3 —4 m/s.

The cut-out speed, however, is the wind speed where the wind turbine stops producing power. When the wind speed reaches the cut-out point, the blades on the wind turbine tilt to reduce lift and induce stalling. The reason for this is because at speeds over the cut-out speed, the blades are spinning too fast, which can damage the wind turbine. The result is that at wind speeds above the cut-out speed, the wind turbine does not produce power. Normally the cut-out speed for commercialized wind turbines is around 25 m/s.

The rated wind speed is the wind speed where the turbine produces its rated power, which means its maximum power. A wind turbines power output will gradually increase from the cut-in speed until the wind speed reaches the rated wind speed. After this point, an increase in wind speed will not result in an increased power output, and the turbine will have a nearly constant output until it reaches the cut-out speed.

The capacity factor is a measure of how well the installed capacity of a wind farm is utilised. If the capacity factor is at 100 % that means that the wind turbines have produced their rated power constantly. The formula for the capacity factor can be displayed as:

$$Capacity\ factor = \frac{Produced\ electricity[MWh]}{Rated\ power[MW] * Time[h]} \tag{2.5}$$

However, the actual capacity factor at wind farms is significantly lower. The capacity factor is highly influenced by the local wind conditions, topography, wake effect, availability, and the turbines specifications.

Figure 2.3 shows a power curve from a wind turbine. The power curve illustrates how much power is produced at given wind speeds. Also illustrated are the cut-in, cut-out and rated wind speeds as well as the rated power.

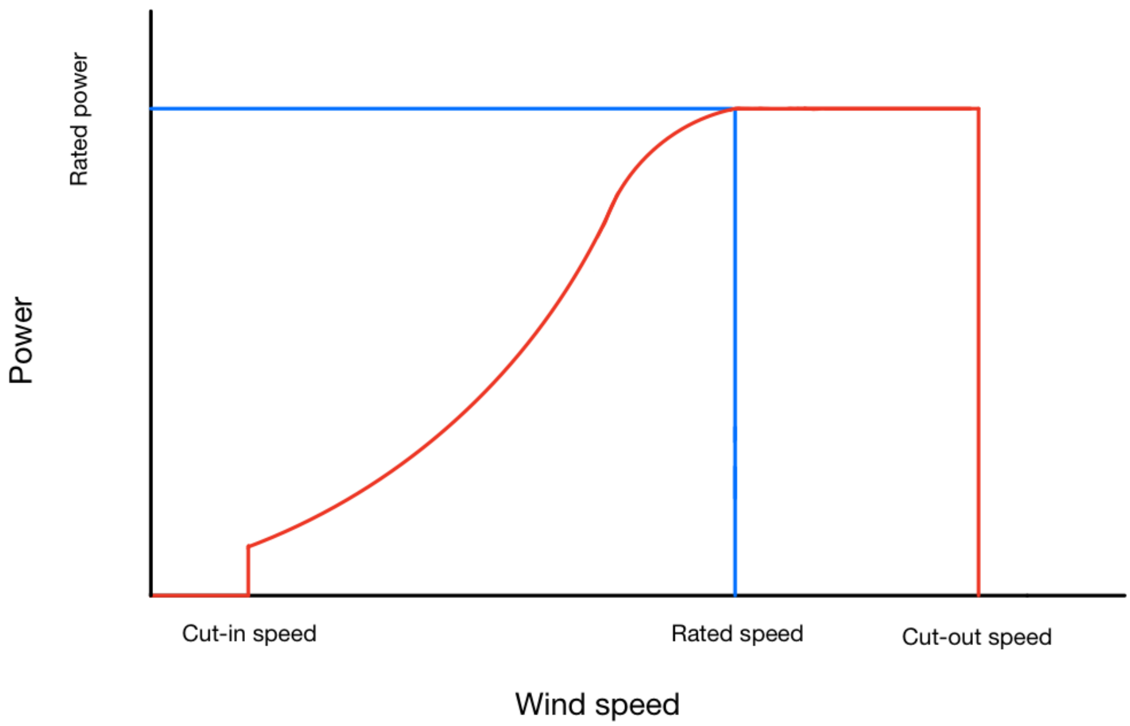

Figure 2.3: Example of a power curve. Cut-in speed, cut-out speed, rated speed and rated power explained in text above.

Wake losses are losses in wind power production due to the kinetic energy behind the wind turbine being lower than in front of the turbine. This happens because the wind is slowed down when it passes the wind turbine, as shown in Figure 2.4. The kinetic energy captured by the wind turbine is converted to electrical energy in the nacelle. Wake losses in wind farms can be from 2 —20 % depending on the distance between turbines and the local turbulence level [20].

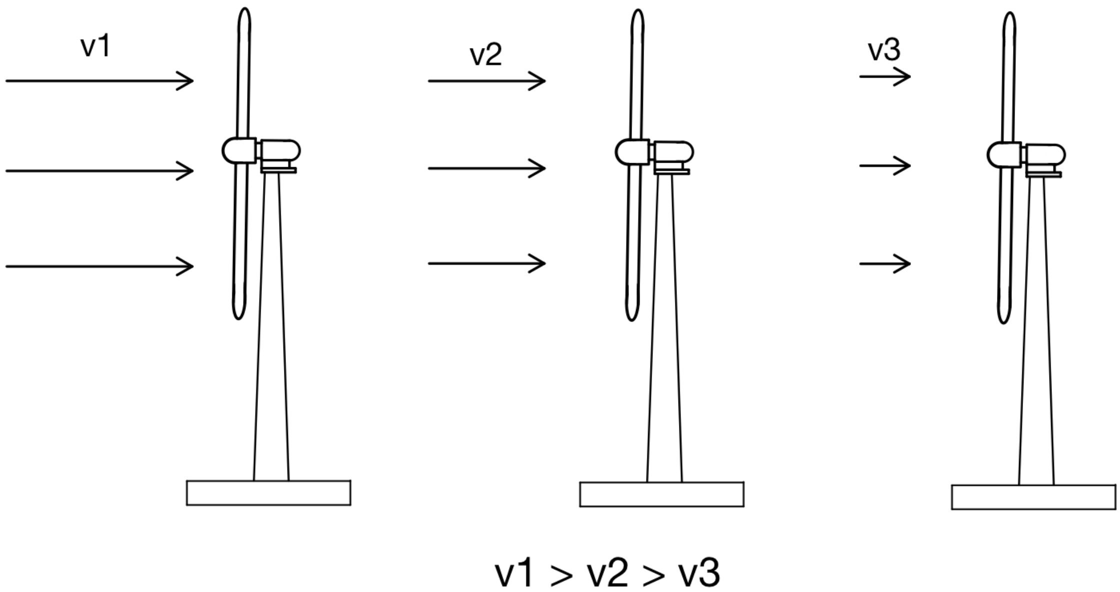

Figure 2.4: Wake effect illustrated. v = wind speed. Arrows illustrating decreasing wind speed.

Availability losses are losses which comes from down time at the wind turbine due to maintenance, faults etc. These losses could be influenced by the weather conditions offshore with regards to strong winds and high waves, which could make maintenance more challenging as well as increase wear on the turbines [20].

2.4 Energy storage

As mentioned previously in this thesis, intermittency is a known problem for wind power and renewable energy in general. The wind park will deliver power in periods where there is sufficient wind available. However, in periods of low wind speeds or no wind at all, other energy sources are needed. One solution is to have a system for energy storage. There are several ways of storing energy, with batteries, thermal storage or pumped hydroelectric as some of the options. In this thesis however, hydrogen will be used as energy storage. Hydrogen is an odourless, colourless, and flammable gas which can be stored in large volumes to be used for large scale energy storage. Today most of the hydrogen produced comes from steam methane reforming, so called grey hydrogen. This type of hydrogen production emits large amounts of CO2 and is not suitable for a zero emission project like the one in this thesis. An option could be blue hydrogen, which is hydrogen made from methane but where carbon capture, utilisation, and storage (CCUS) is applied. With such a system the CO2 is captured and utilised, or stored, which ensures that it is not released into the atmosphere. However, in this thesis only green hydrogen will be looked at. Green hydrogen is hydrogen which is produced using renewable energy, like for instance wind power such as in this thesis. In this section different technologies for green hydrogen production will be looked at together with different technologies for storage and usage of hydrogen.

2.4.1 Hydrogen production

As stated previously, this thesis will look at hydrogen production from renewable energy sources. The hydrogen will be produced through electrolysis which is a process where water molecules are separated into hydrogen and oxygen using electricity. This process is the same for all types of electrolysers, however, what gives them their different names are the electrolyte material used in the component. There are several types of electrolyser technology, however, proton exchange membrane and alkaline are the only commercially available. In this section both types of electrolysers will be described.

Alkaline electrolyser

Alkaline electrolysers are widely regarded as the most mature technology amongst the two and have been commercially used in industry for the last 100 years. The naming comes from the use of a liquid alkaline solution as electrolyte, and the reaction can be displayed as [21]:

$$Anode: 2OH^- \rightarrow H_2O + \frac{1}{2}O_2 + 2e^- \tag{2.6}$$

$$Cathode: 2H_2O + 2e^- \rightarrow H_2 + 2OH^- \tag{2.7}$$

This type of electrolyser is a low temperature electrolyser and has an operating temperature of 60 —95 °C [22]. The efficiency of an alkaline electrolyser varies but is in the range of 65 —82 % [22, 23]. Prices for alkaline electrolysers will also vary to a large degree but is estimated to be between 4.5 —7.5 MNOK/MW in 2020 [22, 24]. An important aspect when considering which type of electrolyser to use is the plant lifetime. The alkaline electrolyser has an expected lifetime of 60 000 —100 000 hours [22, 24, 25].

PEM electrolyser

Proton exchange membrane electrolysers are not regarded as mature of technology and further development is needed to drive down cost and increase efficiency. These electrolysers get their name from the solid polysulfonated membranes, and the reaction can be displayed as follows [21]:

$$Anode: H_2O \rightarrow 2H^+ + \frac{1}{2}O_2 + 2e^- \tag{2.8}$$

$$Cathode: 2H^+ + 2e^- \rightarrow H_2 \tag{2.9}$$

Similar to alkaline electrolysers, PEM electrolysers operate at a relatively low temperature, and the normal operating temperature is between 50 —80 °C [22]. The efficiency of PEM electrolysers also varies but is estimated to be around 65 —78 % [22, 23]. Given that PEM is a less mature technology the price is expected to be higher and will be around 10.2 —12 MNOK/MW in 2020 [22, 24]. The expected lifetime of PEM electrolysers is estimated to be around 20 000 —100 000 hours [22, 24, 25], which is lower than for alkaline electrolysers. Some of the advantages the PEM electrolyser has over the alkaline electrolysers is a smaller area needed, faster response time and a high current density [21].

2.4.2 Hydrogen storage

If hydrogen is to be used as an energy storage solution, there needs to be a way of storing the hydrogen over longer periods at the volume which is required. Hydrogen has a gravimetric energy density of 33.33 kWh/kg [26]. However, at standard temperature and pressure (STP) hydrogen has a density of 0.09 kg/m^3 [27]. This further means a volumetric energy density of 3.0 kWh/m^3. For large scale energy storage, like projected in this thesis, these values are not suitable due to the large volume needed to store the hydrogen. This means that storage solutions which can increase the hydrogen density, and thereby the energy density is needed. In this section of the thesis several different storage solutions for hydrogen will be presented and explained.

Compressed hydrogen storage

Compressed hydrogen is by many regarded as the most mature form of hydrogen storage. It works by compressing gaseous hydrogen to a pressure between 200-700 bar normally. The hydrogen is then stored in pressurised tanks. When hydrogen is pressurised to 350 or 700 bar the density of the hydrogen increases to 23 kg/m^3 and 38 kg/m^3 respectively. Furthermore, this increases the volumetric energy density to 767 kWh/m^3 and 1267 kWh/m^3 respectively [28]. This increase in energy density leads to more compact storage and a smaller area needed. There are however also drawbacks to this solution. One of the drawbacks is that it takes a lot of energy to compress hydrogen to several hundred bar. Around 2—4.2 kWh/kg is needed to compress hydrogen from 20 to 350 bar [29]. This is equivalent to 6 —12.6 % of the total energy content in the hydrogen. Another drawback with increasing the pressure is the increased strain on the storage tanks and the need for more robust tanks. This again leads to higher cost. The high energy consumption and expensive tanks is the reason why lower pressures are preferable in situations where the area allows it.

Subsea hydrogen storage

A possible solution to the problem related to available areas to store hydrogen is subsea storage. If the hydrogen is stored subsea, it would utilise the vast open areas at the sea bottom. At the time of writing there are no subsea hydrogen tanks commercially available. However, TechnipFMC are one of the companies working on it for their Deep Purple project. Their idea is to store compressed hydrogen in pressurised tanks supported by a rigid structure. The storage solution is intended to have a capacity of 12 tonnes of compressed hydrogen [30].

Underground hydrogen storage (UHS)

Since the start of the 1900s, different gases have been stored underground. It began with using depleted oil fields to store natural gas. Caverns, as well as other natural underground formations can be used to store gas. This solution also works for hydrogen and presents another way of doing large scale hydrogen storage. If hydrogen is compressed it can form a gas pocket underground, with the gas pocket being trapped by water underneath and impermeable rock above it. In depleted natural gas caverns, hydrogen can be trapped in the porous rock. When hydrogen is injected into the UHS the pressure increases, and when hydrogen is released from the UHS the pressure will drop. Compared to underground natural gas storage, UHS is a rare storage form, and is more likely to be an alternative in future projects. A promising factor regarding UHS is the projected price. The price could be around \$0.80/kg —\$1.60/kg which would make it the cheapest form of hydrogen storage [28].

Liquefied hydrogen storage

Hydrogen at STP will as mentioned be in a gaseous form. However, if the hydrogen is cooled down to -253 °C or 20 Kelvin at 1 atm of pressure it will turn into a liquid. The main advantage of liquefying hydrogen is to increase the density more than with compression. When liquefied, the density of hydrogen is increased to 71.2 kg/m^3 [31]. This means that the density of liquid hydrogen is 791 times that of hydrogen at STP. Moreover, liquid hydrogen has a density which is 3.1 times that of compressed hydrogen at 350 bar. The volumetric energy density will subsequently increase to 2373.1 kWh/m^3 if the hydrogen is liquefied. If volume of the storage solution is an important factor in a project, this reduction of volume could be beneficial. There are however also some drawbacks with liquid hydrogen. One of the issues is the energy demanded to reach a temperature low enough to liquefy it. The liquefaction process demands around 12.5 —15 kWh/kg, which equals 37.2 —44.6 % of the total energy content in the hydrogen [28]. Another problem with this storage solution are the tanks. To keep the hydrogen cooled to the desired temperature, either well insulated tanks or tanks with active cooling would be necessary. Solutions such as this could increase costs and make the solution less preferable.

Metal hydride storage

Several metals can react with hydrogen at elevated temperatures with the reaction:

$$M + 0.5H_2 \leftrightarrow MH_x + heat \tag{2.10}$$

Metal hydrides can be reversibly discharged and charged and are a form of metallic alloys. These alloys have the capabilities to store large amounts of hydrogen at low pressure. Processes where hydrogen is stored and released are called adsorption and desorption, respectively. The temperature and pressure needed for both adsorption and desorption are determined by the alloy's composition. High volumetric energy density is the main advantage with this technology for hydrogen storage. Depending on the type of hydride, the volumetric hydrogen density could reach 115 —150 kg/m^3, which is significantly higher than some of the other storage options. Another advantage is the low pressure required, which solves a problem with safety concerns regarding high pressure storage [32]. Metal hydrides also demands less energy in the storing process compared to compression and liquefaction. The two other solutions demand double and six times the energy, respectively. There are however also several issues with metal hydride storage. While the metal hydrides have a relatively high volumetric energy density, the gravimetric energy density is relatively low. Normally the percentage wise gravimetric hydrogen density is between 1 —9 %. Other issues are cost of the metals, slow hydrogen uptake rates, and problems regarding the efficiency and reversibility over periods with a high number of cycles [28].

Liquid organic hydrogen carrier

Another possible storage solution for hydrogen are liquid organic hydrogen carriers (LOHC). This storage method works by using LOHC molecules to store hydrogen by binding it to the molecule (hydrogenation). When the hydrogen is stored in the molecules, it has properties similar to liquids produced from crude oil, such as diesel and gasoline. This makes it easier to store and transport compared to compressed or liquefied hydrogen. When there is a need for energy, the hydrogen will be separated from the molecules and can be used as normal (de-hydrogenation). Compared to some other storage methods, LOHC has a relatively low efficiency, which varies with a varying rate of de-hydrogenation. Given a 100 % de-hydrogenation rate, the efficiency of LOHC is 69.17 %. However, the hydrogenation process is an exothermic process, which means it expels heat. If this heat is stored and reused the efficiency could increase to 88.74 % [33]

2.4.3 Hydrogen application

In periods where the electricity from the wind farm is not enough to power the platform, the stored hydrogen will be used to produce electricity. There are several technologies for producing electricity from hydrogen. Some of the alternatives are burning the hydrogen in combustion engines or gas turbines, and run a generator. The problem with this, however, is that the efficiency is low and in the range of 20 —25 % for combustion engines [34]. Because of this low efficiency, this thesis will look at hydrogen fuel cells for power production. In this section of the thesis 3 different types of fuel cells will be described.

Alkaline fuel cell

Alkaline fuel cells (AFC) have been around for decades and was for instance used in the Apollo space missions. Similar to alkaline electrolysers, these fuel cells use an alkaline electrolyte. The chemical reactions happening in the fuel cell are [35]:

$$Anode : H_2 + 2OH^- \rightarrow 2H_2O + 2e^- \tag{2.11}$$

$$Cathode: \frac{1}{2}O_2 + 2e^- + H_2O \rightarrow 2OH^- \tag{2.12}$$

Alkaline fuel cells have an operating temperature in the region of 60 —250 °C [35, 23]. The efficiency of an alkaline fuel cell will vary between manufacturers but is in the region 50 —70 % [36, 23]. Regarding the operational lifetime of this type of fuel cell, it is expected to be in the region 5 000—8 000 hours [23].

PEM fuel cell

Proton exchange membrane fuel cells (PEMFC) are one of the most promising technologies for fuel cells. Today one of their use cases are hydrogen powered cars. One of the reasons for this is their power density, which is the highest for all fuel cells. This means that these fuel cells are compact, which is an advantage if there is limited space available. The reactions for this fuel cell are[35]:

$$Anode: H_2 \rightarrow 2H^+ + 2e^- \tag{2.13}$$

$$Cathode: \frac{1}{2}O_2 + 2H^+ + 2e^- \rightarrow H_2O \tag{2.14}$$

PEMFC usually has a working temperature in the region of 60—90 °C [35, 23]. Compared to AFC the efficiency of PEMFC will normally be lower and is in the region of 30 —60 % [23, 36]. Due to it being a less mature technology, PEMFC is likely to be more expensive than AFC. The operational lifetime of the PEMFC is likely to be in the region of 60 000 hours [23].

Solid oxide fuel cell

Solid oxide fuel cells (SOFC) get its name from utilising a solid ceramic electrolyte. There are different electrolytes available, however the most used is yttria-stabilized zirconia. This electrolyte is an oxygen ion conductor. In SOFC the oxygen molecule (O^2-) is the mobile conductor. This gives the reactions [35]:

$$Anode: H_2 + O^2- \rightarrow H_2O + 2e^- \tag{2.15}$$

$$Cathode: \frac{1}{2}O_2 + 2e^- \rightarrow O^2- \tag{2.16}$$

SOFC are high-temperature fuel cells and have an operating temperature in the region of 600 —1000 °C [35]. This is substantially higher than both AFC and PEMFC. The heat expelled from a SOFC could be used for heating at the oil platform or for chemical processes related to storage solution. The electrical efficiency of SOFC is around the same as for AFC and in the region of 50 —70 [23, 36]. However, if the heat is collected the total efficiency could reach around 90 % [35]. SOFC is compared to AFC regarded as a less mature technology, with an expected higher price. The operational lifetime of SOFC could be up to 90 000 hours [23].

2.4.4 Saltwater desalination

As mentioned previously, hydrogen is produced from the separation of water molecules trough electrolysis. The water used in this process needs to be fresh water. The system projected in this thesis will be located far offshore with little fresh water supply. Therefore, some sort of seawater desalination is required. This process utilises reverse osmosis or thermal technologies. Reverse osmosis is however the dominant technology due to its lower footprint and lower energy demand. The energy demand in a saltwater desalination process will increase with increasing salinity. For seawater, the minimum energy requirement for desalination is 1.1 kWh/m^3[37]. Given that it takes 9 kg of water to produce 1 kg of hydrogen, this process uses 0.0297% of the energy in 1 kg hydrogen.

2.4.5 Platform for electrolysers and fuel cells

Given that the entire energy system is intended to be placed offshore, some sort of platform or floater must be included to place the electrolysers and fuel cells on. The floater or platform in question will need to have space for [25]:

- Saltwater desalination facility
- Storage for feed water
- Electrolyte system
- Electrolysers
- Dryer and separator system
- Compensators
- General area for safety system
- Living quarters for maintenance work

The price of the platform will be highly dependent on the weight and footprint of the components placed on it. As for the other components for the hydrogen system there are uncertainties related to the cost. [38] estimates a cost of 1.74 MNOK per MW of electrolysers placed on a floater. However [25] assumes a cost of 36.9 MNOK per MW of electrolysers placed on a bottom-fixed platform.

2.5 Relevant laws and regulations

For a project like the one in this thesis there are several laws and regulations which will need to be followed for it to be executed. In this section, some of the most relevant laws and regulations will be explained briefly.

2.5.1 The Offshore Energy Act and The Petroleum Act

If an offshore wind farm is to be built on Norwegian controlled waters under international law, it needs to follow The Offshore Energy Act [39]. The Offshore Energy Act covers the Norwegian Economic Exclusive Zone along the Norwegian coast. For an offshore wind farm to be built it needs to receive a licence. For these licences to be obtained, the government must decide to open certain areas for wind power production. If an area is to be opened, environmental assessments will need to be conducted [40]. Furthermore, if the intended wind farm is meant to be connected to the grid at the mainland, The Energy Act must also be followed [25]. To this day only two areas have been opened for license applications. These two areas are Sørlige Nordsjø II and Utsira Nord [41]. These areas are intended for bottom-fixed and floating wind turbines, respectively. Even though both areas are opened, no licensing round has started as of May 2022.

However, offshore wind farm projects could be exempt from the offshore energy act if the construction is not connected to the grid at mainland, but only to an offshore platform like the one in this thesis. A prime example of this is the Hywind Tampen project which is mentioned in subsection 2.1.2 and discussed in depth in both [42] and [43]. The construction of Hywind Tampen, which is intended to partly power the Snorre and Gullfaks field, is permitted through the petroleum act [25]. The Ministry of Petroleum and Energy considers Hywind Tampen a modification of the oil and gas license issued for the Snorre and Gullfaks areas [44]. This is despite the fact that the Petroleum Act does not mention wind farms for electrification of oil and gas platforms.

2.5.2 Beneficial tax treatment

The tax system for the petroleum industry is intended to ensure that the production of oil and gas will benefit the entire society. The taxation system made for the oil and gas industry is similar to the taxation system used for ordinary companies in Norway. This means that there is a 22 % company tax. However, due to the major incomes from oil and gas production, the petroleum companies have an additional tax of 56 %. This means that the total tax rate for petroleum companies in Norway is 78 % [45].

As mentioned above, the construction of Hywind Tampen is considered an alteration of existing structure under the petroleum act. This further means that the construction of the wind farm is considered an expense for the company. Given the tax rules for the petroleum industry this means that 78 % of the expenses related to Hywind Tampen could be written off the tax bill [46]. If the same tax write off is applicable to a system like the one in this thesis, it could have a major impact on the economic feasibility.

Since the petroleum companies have an additional tax of 56 % this will as mentioned increase the tax write off compared to other companies. This further means that the tax write off for wind farms constructed under The Offshore Energy Act will be considerably lower at only 22 %. Furthermore, wind farms built onshore will also have a lower tax write off than wind farms licensed under The Petroleum Act. This increased tax write off for wind farms licensed under The Petroleum Act lowers the total cost, which could accelerate plans for wind farms.

2.5.3 CO2 tax and carbon credits

Oil and gas platforms on Norwegian soil primarily produce power locally from burning gas, which leads to high amounts of released climate gases, with CO2 as the most common. This power production is the reason that oil and gas platforms are the second largest emitters of climate gases on Norwegian soil, and releases 27% of Norway's total emissions [47]. In an effort to reduce CO2 emissions from all sources, including oil and gas production, taxes on CO2 emissions have been implemented in Norway. In addition to this the oil and gas industry needs to take carbon credits into account. The CO2 tax is, together with the carbon credits, considered to be essential tools to reduce climate gas emissions. Businesses in the European Union (EU) which are part of the European Union Emissions Trade System (EU ETS) share the carbon credits amongst them.

EU

As mentioned above, businesses in the EU which are included in this system need to buy carbon credits when releasing climate gases into the atmosphere. According to the European commission it is the first, and biggest, major carbon market in the world. The point of the EU ETS is to gradually decrease climate gas emissions in the EU countries. This is done by having a certain amount of carbon credits which businesses implemented in the EU ETS needs to buy, depending on their emissions. One carbon credit is the equivalent of releasing 1 tonne of CO2-equivalents. Each year the total amount of carbon credits is reduced, which ensures that the total emissions go down. If a business ends up with too many credits they can either sell them, or save them for next year. On the other hand, if a business does not have enough carbon credits they will need to buy more [48].

The price of carbon credits is varying from year to year. However, a market stability reserve (MSR) has been created to stabilize the cost. If there are too many credits in the market, the price will drop, and a portion of the credits are moved to the MSR. On the other hand, if there are too few credits on the market, the price will increase, and credits are released from the MSR to limit the price increase.

The Norwegian Water Resources and Energy Directorate (NVE) has made a forecast for how they think the price of carbon credits in the EU ETS will increase in the coming years. In 2020 the average carbon credit price was around 25 Euro/tonne. They estimate an increase which will take the price to a place between 39 and 83 EUR/tonne in 2040, although they emphasise that these numbers are connected to a high level of uncertainty [49].

Norway

Some Norwegian businesses are obliged to follow the EU ETS trough The European Economic Area Agreement. Most of the emissions from oil and gas production, industry and aviation are included in the EU ETS. However, in Norway there is as mentioned also an added carbon tax and methane tax [50]. While the EU ETS has a limit of how much CO2-equivalents it is possible to emit, the carbon tax in Norway does not have a limit, and businesses pay a fixed sum for each tonne of CO2 they emit. This CO2 tax is to be increased every year to drastically cut the climate emissions. The Norwegian government has suggested to increase the total cost of CO2 emissions to 2000 NOK/-tonne in 2030. This means that the CO2 tax for businesses included in the EU ETS will be adjusted so that the total price is 2000 NOK/tonne [51].

Implications for this thesis

The EU ETS and the CO2 tax are as mentioned important for the results of this thesis. Since the platforms normally burn gas to produce electricity, they emit enormous amounts of climate gases. These emissions will, due to the prices mentioned, be more and more expensive. With a zero-emission project like this these costs are eliminated, which affects the net present value of the project. This further means that a continued increase in CO2 tax and carbon credits will be beneficial for the realisation of the project.

Chapter 3

Methods

Figure 3.1 illustrates the overall layout of the proposed energy system. A floating wind farm produces electricity to a platform. In periods of overproduction of electricity, hydrogen is produced in electrolysers from the surplus and transported to subsea hydrogen tanks at the sea bottom. When there is an underproduction of electricity from the wind farm, hydrogen is used to produce electricity in a fuel cell to cover the shortage of electricity. This system is an off-grid system which is 100 % dependent on the wind farm and hydrogen system.

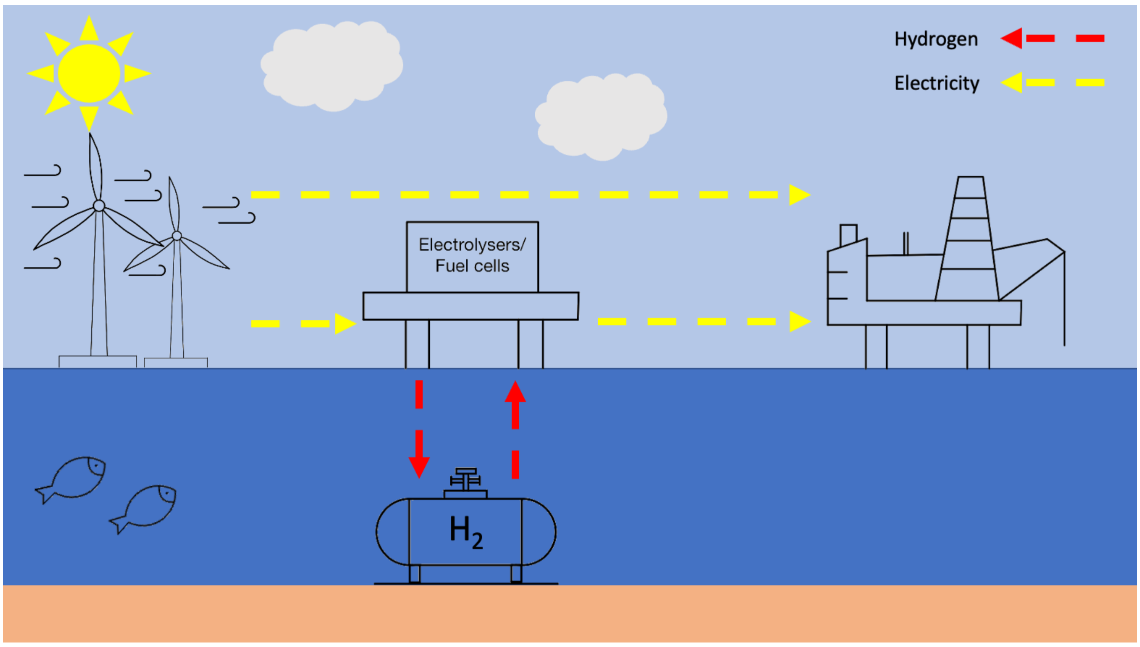

Figure 3.1: Proposed energy system. A wind park powers an oil platform. When there is a surplus of electricity the power is sent to electrolysers on an external platform and hydrogen is produced before it is stored subsea. If there is a shortage of electricity, hydrogen is released from the tanks and electricity is produced in fuel cells at the external platform. The electricity is then sent to the platform.

The first part of this chapter will look at the components chosen for the hydrogen system before showing how the various capacities for the system is calculated. Furthermore, the datasets used will be explained as well as the parameters chosen. The next parts of this chapter will look at Monte Carlo simulations, techno-economic calculations, and the use of a gas turbine to work alongside the hydrogen system as backup. Lastly this chapter will explain how different locations have been compared to assess the influence of the wind conditions on the feasibility of the project.

3.1 Components chosen for hydrogen system

In section 2.4 several different technologies for electrolysis, hydrogen storage, fuel cells and the external platform where presented. In this section, the choice of technology these components will be explained

3.1.1 Electrolysers

As explained, there are several differences between alkaline electrolysers and PEM electrolysers regarding price, efficiency and expected lifetime. In this thesis alkaline electrolysers will be utilized. For projects like the one in this thesis the efficiency will be of great importance as the higher the efficiency, the less capacity is needed for both the hydrogen system and the wind park. Subsequently, the cost of the components is also of high importance. It is expected that costs for PEM electrolyser systems will drop in years to come, however, the current difference in price is significant and makes PEM less favourable.

3.1.2 Storage

There are as mentioned several different options for storing hydrogen. Several considerations need to be taken to determine the right solution, and the preferred solution could vary from project to project. In this thesis subsea compressed storage is the chosen storage solution. As with the hydrogen production, the efficiency of the storage solution is of high importance. This makes compressed hydrogen a good alternative given the relatively low energy demand for compression. However, given the expected high volume required for this project, it is thought to be unlikely to place hydrogen tanks on an oil platform or another topside construction. Subsea hydrogen storage is as mentioned in chapter 2 not commercially available but is expected to be within a relatively short time frame. Given the low price estimate mentioned for underground hydrogen storage, this could also be an option long term. It is however difficult to predict the feasibility of this storage solution on a general basis given that not all locations would be appropriate.

3.1.3 Fuel cells

Same as for the electrolysers and storage tanks, the price and efficiency will be of high importance when it comes to fuel cells. Given that AFC is a more mature technology than its competitors it is expected to have a lower price. Furthermore, same as for the electrolysers, the efficiency of AFC is higher than PEMFC and also higher than SOFC. In the planning of a real life project, several factors must be considered when choosing which type of fuel cell to use. Factors such as ramp-up rate, footprint, maintenance, and suitability regarding offshore locations will need to be assessed. In this thesis prices for PEMFC will be used due to references available at the time of writing as well as the long lifetime presented, compared to the lifetime of AFC.

3.1.4 External platform

In section 2.4 two different estimates have been obtained for the cost of the external platform which is intended to house the electrolyser and fuel cell systems. The two cost estimates are for a floater, and for a bottom-fixed platform. Given the difference in price between the two options, the platform could either be a relatively small part of the investment costs, or a major part. This thesis will use the platform from the Greenstat report [25] due to the extent of information in the source. The price for the chosen platform is presented with the electrolyser cost included in the report. However, in this thesis the price of the electrolyser will be subtracted from the price. This ensures that the price presented is for the platform itself.

3.2 Calculating capacity for wind farm and hydrogen system

To calculate the capacity of the wind farm and hydrogen system, a dataset for the produced wind power at Gullfaks, and consumption data at a platform is used. Efficiency numbers and caloric values for hydrogen are also used. In this section these datasets and values will be further explained, and a walkthrough of the different calculations will be made.

3.2.1 Datasets

Oil platform

Consumption data from an oil platform was gathered by contacting several companies. Lundin Energy was willing to share detailed data [52]. The data was received in an excel file with hourly consumption data over a 13 month period. To be able to use the data, the consumption data as well as the time was filtered out and uploaded into Python. The power consumption at the platform is relatively consistent as it operates both at day and night. However, as shown in Figure 3.2 there are variations. The sudden sporadic drops in power consumption, which is illustrated, comes from downtime often due to maintenance. Calculations show that the average real power consumption from the platform is 27.1 GWh annually. Given a gas turbine efficiency of 30% [53] and a natural gas energy content of 13.6 kWh/kg [54], the annual gas consumption is calculated to be 64362 tonnes.

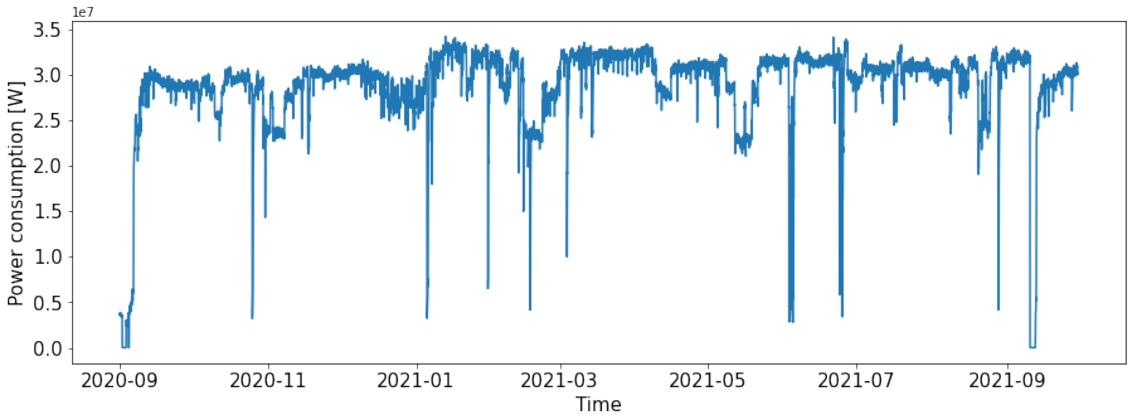

Figure 3.2: Platform power consumption. Y-axis is 1e7.

The calculations in this thesis will use wind data from a period significantly longer than 13 months. Because of this, the consumption data from the platform was duplicated several times to form a timeline which is as long as the available wind data. The consumption data is as mentioned for 13 months, so by adding the data together the months will be skewed. However, there does not appear to be any seasonal variations, so this is not expected to influence the end result. The consumption for the platform will be used for all the locations in this thesis, even though there are no platforms at those locations. At platforms run by fossil fuels, the turbines produce heat for the platform, and this heat will need to be replaced when using a fossil free system. In this thesis this will not be taken into account.

NORA 3

When calculating the needed capacity for the wind farm and hydrogen system, as well as the cost and net present value for the project, it is important to have data on wind resources. This thesis uses the Norwegian hindcast archive (NORA3) [55]. NORA3 contains simulated wind data from 1996 until 2019 with a 3-kilometre resolution and is validated for the North Sea and the Norwegian Sea [56].

From NORA3 a dataset called NORA3-WP [57] is produced. The hourly produced power in NORA3-WP is calculated using the equation [58]:

$$P_w(i) = C_r P_{w,n}(i), \qquad P_{w,n}(i) = \begin{cases} 0, & u(i) < u_{ci}, \\ \frac{u(i)^3 - u_{ci}^3}{u_r^3 - u_{ci}^3}, & u_{ci} \leq u(i) < u_r, \\ 1, & u_r \leq u(i) < u_{c0}, \\ 0, & u_{c0} \leq u(i). \end{cases} \tag{3.1}$$

Equation 3.1 shows, as mentioned above, the produced power from the wind turbine for every hour in the dataset. The produced power is a product of C_r which is the rated capacity of the turbine, and $P_{w,n}(i)$ which is the power conversion function which is normalized and non-linear. $P_{w,n}(i)$ is determined based on the wind speed. u(i), $u_{ci}(i)$, $u_{co}(i)$ and u_r show the given wind speed, cut-in wind speed, cut out wind speed and rated wind speed, respectively.

NORA3-WP [57] is intended to be used in the planning phase for new wind farm projects to get information on wind speeds and produced power. The produced power is calculated for three different wind turbines with rated power of 6, 10 and 15 MW. The data is available as hourly data and will be used together with the power consumption from an oil platform to calculate surplus or deficit of power. The production at a given location is plotted in Figure 3.3 and shows the variability in the production.

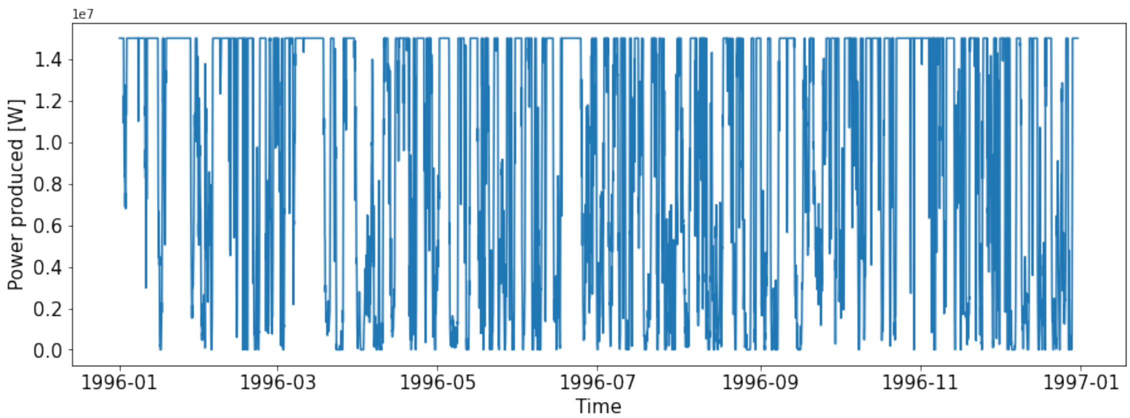

Figure 3.3: Power production from a 15 MW wind turbine. Y-axis is 1e7.

The NORA 3 dataset has gone through a validation process to determine if the simulated values are realistic. The validation process showed that NORA3 provides good estimates for wind power production. However, the estimates have shown to be conservative on the offshore wind metrics. The capacity factor has an underestimation of around 3 % which comes from the wind speeds being 5 % lower than observed wind speeds typically. No measures will be taken in this thesis to compensate for the conservative measurements.

The data in NORA3 represents a single wind turbine which is not affected by wind park losses. Normal wind park losses are wake effect, availability losses and electrical losses. In this thesis several wind turbines will have to be used to power the system, and therefore wake effect will need to be accounted for.

Storm Geo separates between large and small wind farms with wake losses ranging from 5 —13 %. The wind farms in the report with an installed capacity similar to what is excepted for this thesis have wake losses in the range of 5 —7 %. However, the turbines used in the Storm Geo report are smaller than the 15 MW turbine used in this thesis [20]. This leads to a higher number of turbines in the wind park which could have an effect on the wake losses. For this thesis the wake losses are set to 5 %.

Further, Storm Geo sets the availability to between 94 —95 % which translates to 5 —6 % availability loss [20]. In this thesis the availability will be set to 95 % which again means availability losses of 5 %.

For the calculations in this thesis, it is necessary to have a number for total losses in the wind park. This value will then be used to calculate the available energy from the wind park with wake effect and availability losses included. The available energy will be calculated with the formula:

$$Energy\, available = (1 - wake\, loss) * (1 - availability\, loss) \tag{3.2}$$

This further leads to the energy available to be 90.25 % of the energy in the NORA 3 dataset. This number will further be multiplied with the output in the NORA 3 dataset before capacity calculations are made.

3.2.2 IEA reference turbine

In this thesis the IEA 15 MW turbine has been chosen as energy source. The turbine is designed by staff from the National Renewable Energy Laboratory (NREL) and the Technical University of Denmark (DTU). Its intention is to be a reference for industry and academia to development of offshore wind power. Details on design, dimensions and technical features are available online [59]. As previously mentioned, wind turbines are constantly increasing in size. Given this development it is likely that turbines used in a project like the one in this thesis would be 15 MW or more.

The key parameters for the 15 MW reference turbine are listed in Table 3.1:

Hub height	150 m
Rotor diameter	240 m
Cut-in wind speed	3 m/s
Cut-out wind speed	25 m/s
Rated wind speed	11 m/s

Table 3.1: Key parameters for the 15 MW wind turbine used in this thesis. Data from [59]

3.2.3 Assumed efficiency values for capacity calculations

In the capacity calculations several parameters are necessary, as well as the data sets used. The parameters include efficiency values, caloric values for different substances as well as physical values such as density. These values have been gathered through literature studies and have been crosschecked with several sources. In chapter 2 these parameters have been explained and often presented as an interval. In this section, the assumptions for different parameters will be laid out. Table 3.2 shows the efficiency values chosen for the hydrogen system.

Component	Efficiency
Electrolyser	70% (LHV)*
Desalination	99% [37]**
Compression	90%*
Fuel cell	60% (LHV)*
DC/AC inverter	95% [60]

*Table 3.2: Assumed efficiency values for hydrogen system. *Assumed based on efficiency intervals provided in section 2.4. **Calculated based on electricity consumption presented by reference.*

3.2.4 Capacity calculations

When calculating the necessary capacity for the wind farm and hydrogen system, the hourly wind data and consumption numbers are of high importance. The wind data from NORA 3 - WP is imported as produced power from the 15 MW IEA reference turbine described previously. The wind data could as mentioned be from the entire Norwegian Sea and North Sea. In this part of the thesis the chosen location is the Gullfaks field, which is chosen due to the high capacity factor.

Wind farm and hydrogen storage

The python code for estimating capacity works as illustrated in Figure 3.4. The hourly consumption data from the oil platform is subtracted from the hourly data for produced power from the NORA3-WP data set. This leads to there being either a surplus or a shortage of electricity every hour. As previously shown in Equation 3.1, if the wind speed is under the cut-in speed or above the cut-out speed, the wind farm produces zero electricity, and the system is powered entirely from the hydrogen fuel cells. If there are some wind but not enough to power the platform, the hydrogen system will fill in the gap between produced electricity and the consumed electricity. On the other hand, if there is a surplus of electricity from the wind farm it is possible to produce hydrogen. The code in python has a max limit for storage capacity added in. This ensures that when the hydrogen tanks are full there will be no hydrogen production. When the hydrogen tanks are below the max limit, and there is a surplus of electricity, hydrogen is produced. The amount of produced or used hydrogen every hour is put into a data frame. For every hour the produced or used hydrogen is added to or subtracted from the total tank volume. The hydrogen volume is at the beginning of the time series set at max capacity. It is assumed that the hydrogen tanks are filled up before the system is implemented. By adding or subtracting hydrogen for every hour the tank volume varies accordingly during the 23 years of data. The needed storage capacity is decided using the plot of the tank volume over the entire period. If the tank volume is always above zero, there will always be energy available. An increased capacity at the wind farm is assumed to be leading to a lower demand for hydrogen storage, and there are different configurations available regarding capacity. Because of this, two different configurations are made, with a varying capacity for the wind farm and hydrogen storage. The two different configurations utilise 8 and 7 wind turbines, with 600 and 750 tonnes of hydrogen storage, respectively.

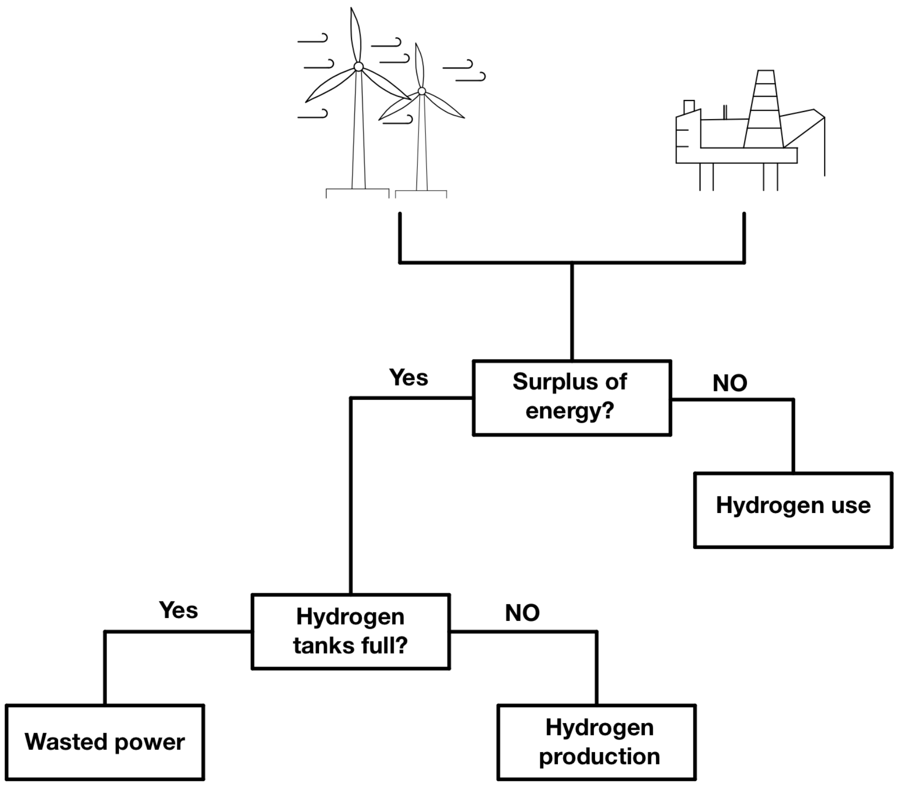

Figure 3.4: Flow chart of calculations for energy system using wind power and hydrogen.

Electrolysers and fuel cells

Given that this is an off-grid system, which is mainly dependent on the wind farm, the capacity for electrolysers will be dependent on the capacity off the wind farm. It will be assumed that all surplus power from the wind farm will be used to produce electricity. Therefore, the electrolyser capacity will be decided by the maximum surplus. The data frame in python containing produced and used hydrogen per hour has a maximum value for produced hydrogen. By using the efficiencies for produced hydrogen as well as the energy content in the hydrogen it is possible to calculate the needed electrical capacity for the electrolysers. The fuel cell capacity will be found from the maximum consumption at the platform which in chapter 2 was established to be 34 MW. Equation 3.3 show the calculations made for estimating the electrolyser capacity and Equation 3.4 show the calculations made for estimating the fuel cell capacity. η_{hp} is the efficiency for hydrogen production, and η_{hu} is the efficiency for hydrogen usage. The gravimetric energy density of hydrogen is, as mentioned in chapter 2, 33.33 kWh/kg.

$$Electrolyser\ capacity\ [kg/h] = \frac{Maximum\ hourly\ surplus\ of\ electricity\ *\ \eta_{hp}}{Gravimetric\ energy\ density\ of\ hydrogen} \tag{3.3}$$

$$Fuel\ cell\ capacity\ [kg/h] = \frac{Maximum\ power\ consumption\ at\ platform}{Gravimetric\ energy\ density\ of\ hydrogen\ *\ \eta_{hu}} \tag{3.4}$$

3.2.5 Tank capacity utilisation

The tank capacity will as mentioned be determined from the fact that there always must be hydrogen available, and the tanks can never be empty. As a way of assessing how well the tank volume is being used, it is of interest to find out how much time the hydrogen volume is below certain levels. A for-loop will be made. The for-loop checks if the hydrogen volume is below certain levels and appends a point to a list for the given threshold for every hour below the limit. By dividing the list on the total amount of hours in the timeline it is possible to find a percentage of time the hydrogen volume is below certain limits.

3.2.6 Wasted power

As illustrated in Figure 3.4 some of the power in this off-grid system will be wasted. Given that this wasted power potentially could be used, it is beneficial to know the amount. The python script calculates the wasted power by first calculating the surplus or shortage of electricity every hour. If there is a surplus and the hydrogen tanks are full the surplus energy is appended to a list called wasted power. The sum of this list is the amount of power wasted. The wasted power will be calculated as the average annual amount. In addition to this, the amount of hydrogen which is possible to produce with the wasted power will be calculated. The amount of hydrogen will be calculated using Equation 3.5, where again η_{hp} is the efficiency used for hydrogen production.

$$Hydrogen\ from\ wasted\ power = \frac{Wasted\ power * \eta_{hp}}{Gravimetric\ energy\ density\ of\ hydrogen} \tag{3.5}$$

3.3 Monte Carlo simulations

Monte Carlo simulations can be explained as a calculation technique where numbers, which are generated randomly, are used to solve various tasks [61]. In the calculations made there are as mentioned many values for efficiencies and for losses in the wind park. The values for efficiency of a given component can vary to a large degree between manufacturers. Furthermore, the losses in a wind park will vary given variations in size of the wind park, the configuration of the wind turbines and the location. This means that there is a high degree of uncertainty connected to these values. For this reason, it is of interest to see how the results varies given a variation in the efficiency values and the wind park losses. A Monte Carlo simulation will therefore be made for both.

3.3.1 Alternating efficiency values

All efficiency values will be picked randomly using a triangular distribution. A triangular distribution has a lower and an upper limit as well as a peak in the middle as shown in Figure 3.5. The peak will be set as the value chosen for the various efficiencies in subsection 3.2.4. The lower limit will be 0.15 lower than peak value, and the upper limit will be 0.15 above the peak value. If the upper limit exceeds 1 it will be set to 1 given that efficiencies cannot exceed 100%. The Monte Carlo simulation will then be executed as described above. By having the individual parameters picked randomly within an interval, the total efficiency will have a high degree of variation when the parameters are multiplied together.

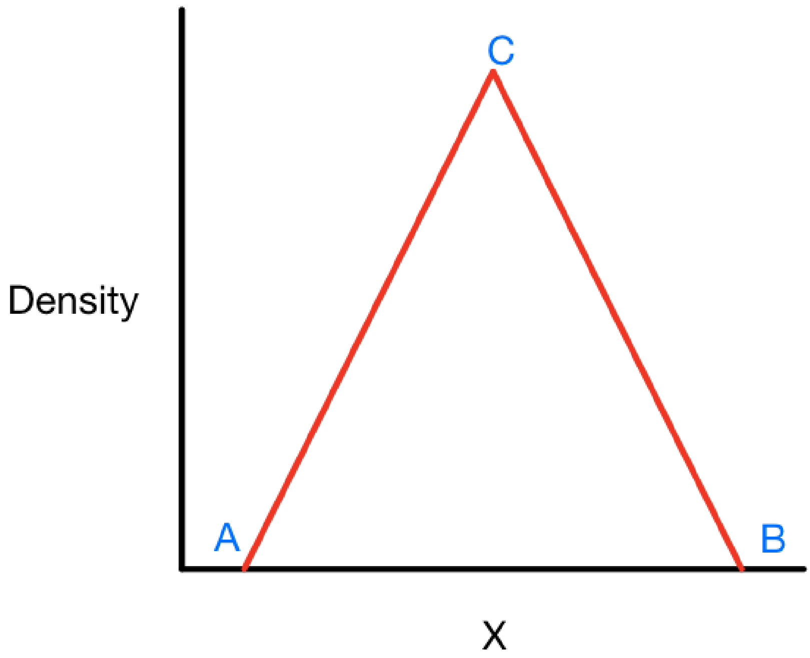

Figure 3.5: Illustration of a triangular distribution with minimum and maximum values at A and B and maximum density at C. Density points to likeliness of picking a certain value. Figure adapted from [62].

3.3.2 Alternating wind park losses

Same as for the varying efficiencies, the values for wind park losses will be picked randomly from a triangular distribution. The peak will also here be set as the value chosen in subsection 3.2.4. The lower limit will be set to 0, while the upper limit will be set to 0.1 for both wake losses and availability losses. In this scenario, the alternating wind park losses will also be combined to form a total loss for the wind park as shown in Equation 3.2.

3.3.3 Plotting of Monte Carlo simulations

The Monte Carlo simulation will produce a plot with 1000 graphs showing the various hydrogen volumes along the 23 years of data. The plots for the alternating efficiency values and the alternating wind park losses will be plotted both with and without a max hydrogen tank capacity. By plotting the graphs without a maximum hydrogen tank capacity, the spread of the results is easy to visualize. On the other hand, by plotting the graphs with the same maximum capacity as in subsection 3.2.4 it will be easy to see which efficiency values makes the hydrogen volume fall below zero. This again points to insufficient energy storage.

3.4 Techno-economic analysis

After the capacity for the wind park and hydrogen system have been calculated in section 3.2 it is of interest to calculate the costs related to the project. In this section the capital expenditures (CAPEX) and the operational expenditures (OPEX) chosen for the different components will be looked at. The CAPEX and OPEX values illustrate the initial investment costs and the cost of operation and maintenance, respectively. Moreover, the methods and data for calculating investments costs and net present value (NPV) in 2020 and 2030 will be explained. All components will be assumed to have a lifetime of 30 years. The calculations will be made for configuration 1 with 120 MW wind power capacity and 600 tonnes of hydrogen storage.

3.4.1 CAPEX and OPEX values

The price of different components has been mentioned in chapter 2 often with an interval. Furthermore, the values are the believed best estimates based on contact with the industry, literature research and considering the large uncertainties connected with them. Table 3.3 shows the CAPEX and OPEX values used in this thesis. The values for the wind park, electrolysers, fuel cells and external platform will be given as NOK/MW while the cost for hydrogen storage will be given as NOK/kg.

When the lifespan of a wind farm is over, the wind farm needs to be removed. This is what's called wind farm decommissioning. Before a wind farm project is approved, a plan for the decommissioning process must be in place. Given that wind farm projects onshore have been around for a long time, there are many projects which have already been decommissioned. However, for offshore floating wind power it is different. No projects have reached that stage of the project yet, which leads to a high degree of uncertainty regarding decommissioning cost. When a project is decommissioned, it normally involves a process with reverse assembly [63]. Given that a wind turbine consists of a lot of metal, there are large values which could be retrieved by selling scrap metal. Because of uncertainty around the current and future cost of scrap metal, the resulting cost of decommissioning is varying to a high degree. Both [64] and [65] points at the total cost of decommissioning to be close to zero or even negative. The net zero cost or potentially negative cost comes from the residual value of wind farm components being equal to, or higher than, the cost of the reverse assembly. In this thesis the decommission cost will be set to zero.

Components	CAPEX	OPEX
Wind park 2020	57 [MNOK/MW] [19]	0.9 [MNOK/MW/year][19]
Wind park 2030	25 [MNOK/MW][19]	0.7 [MNOK/MW/year][19]
Electrolysis 2020	7.5 [MNOK/MW] [24]	0.15 [MNOK/MW/year]**
Electrolysis 2030	3.9 [MNOK/MW] [24]	0.078 [MNOK/MW/year]**
Fuel cells 2020	13 [MNOK/MW] [66]	0.26 [MNOK/MW/year]**
Fuel cells 2030	10 [MNOK/MW] [66]	0.2 [MNOK/MW/year]**
Hydrogen storage	7721 [NOK/kg]*	—
External platform	36.9 [MNOK/MW][25]	—

*Table 3.3: Cost parameters. *Estimated after conversations with industry and TechnipFMC. **Estimated to be 2 % of CAPEX*

3.4.2 Investment cost

The investment cost will be calculated for both investment in 2020 and in 2030. The CAPEX values in Table 3.3 will be used together with the needed capacity for the different components. The wind park, electrolyser and fuel cell values are used with the needed MW for each component. The storage CAPEX will be used together with the chosen tank capacity. The cost of the external platform will be calculated using the given CAPEX and the calculated capacity of electrolysers and fuel cells.

Given that it is expected that the hydrogen storage will be a major part of the total investment cost, it is of interest to calculate investment cost with storage as a variable. Therefore, a plot will be made showing total investment cost with varying storage capacity.

3.4.3 Net present value

The net present value (NPV) can be explained as the present value of a future amount of money. Given that the future incomes and costs related to a project will have a different value than today, the money will have to be converted to the present value. The positive or negative result of an NPV calculation will indicate if a project is profitable or not [67]. The equation for calculating NPV is shown below [68]:

$$NPV = \sum_{t=0}^{n} \frac{NCF_t}{(1+r)^t} \tag{3.6}$$

where NPV is the net present value, NCF is the net cash flow in year t and r is the discount rate. In the first year the NCF includes the total investment cost in year 0 which is calculated based on CAPEX and needed capacity.

To calculate the net present value, a function in Python called numpy.npv() [69] will be used. The different inputs in the formula are the investment costs, the cash flow for every year in the projects lifetime and discount rate.

The investment costs mentioned above will be used in the NPV calculations. This means that the NPV calculations also will use investment in both 2020 and 2030.

The net cash flow (NCF) will be calculated for the years 2020 —2060 and consists of calculating the sum of expenses and incomes every year as shown in Equation 3.7. The numpy.npv() function in python has investment cost as a separate input as mentioned. This means that the total investment cost is not included in the NCF in the first year, which gives the equation:

$$NCF = -OPEX + natural gas\ savings + carbon\ tax\ savings \tag{3.7}$$

The expenses include OPEX for the wind park, electrolysers and fuel cells as listed in Table 3.3. The income or savings will include the natural gas saved as well as the carbon price which is saved by using an emission free system. The amount of natural gas saved will be calculated as:

$$Amount\ of\ natural\ gas = \frac{Annual\ Power\ Consumption\ At\ Platform}{Energy\ Content\ NaturalGas * Efficiency\ Gas\ Turbine} \tag{3.8}$$

The annual power consumption will be found from taking the sum of the first year of the consumption data. The energy content in natural gas will be set to 13.6 kWh/kg [54], and the efficiency of the gas turbine will be set to 30% [53]. The amount of natural gas saved will be used together with the natural gas price which is described below.

When the investment costs and cash flow have been calculated, the discount rate (r) must be determined. The discount rate is the required rate of return which is used for calculating the NPV [70]. The chosen discount rates are explained below.

In this thesis the net present value will be calculated for the configuration of wind and hydrogen which is described in subsection 3.2.4 which uses 8 wind turbines and 600 tonnes of hydrogen storage. As mentioned, the NPV will be calculated for both 2020 and 2030. Furthermore, 3 different values for the discount rate will be used for both years. The value for the discount rate will be explained below.

Natural gas price

For the NPV calculations the natural gas price will be a saving as mentioned above. The price of natural gas will therefore have an impact on the profitability of the project. It is uncertain what the natural gas price will be in the future, so an estimate is needed. The estimate will come from NVE's projected prices for 2025, 2030 and 2040 [49]. The value for 2035 will be estimated by interpolation. Subsequently the values for the years 2020 to 2060 will be estimated by using linear regression in Microsoft Excel. This will give a value for the natural gas price for every year in the calculations.

CO2 price

The total CO2 price is, as mentioned in subsection 2.5.3, intended to be increased to 2000 NOK/tonne in 2030. In 2021 the Norwegian CO2 tax was 543 NOK/tonne. If the carbon credits from EU ETS is added, the total price of CO2 emissions were around 1000 NOK/tonne [71]. This thesis will use a linear increase from 1000 NOK/tonne in 2020 to 2000 NOK/tonne in 2030. Since the carbon price beyond 2030 is yet to be determined the price will be set to a fixed value of 2000 NOK/tonne for the years 2030 —2060.

Discount rate

As shown in Equation 3.6, the net present value uses the discount rate (r) as a parameter. The discount rate will as mentioned above have a significant effect on the NPV. In [49] NVE have used a discount rate of 6 %. This report will use 6 % as the middle value but will also calculate NPV with 4% and 8 % discount rate.

3.5 Hybrid backup system

Given the expectation that the hydrogen storage will be a major part of the investment cost, it is of interest to investigate ways of cutting storage needs. One solution is to use a natural gas turbine similar to what already exists at most platforms. A natural gas turbine could be used in periods with large power shortage, to both reduce fuel cell capacity and storage tank capacity. The python script for this part of the thesis will work as illustrated in Figure 3.6:

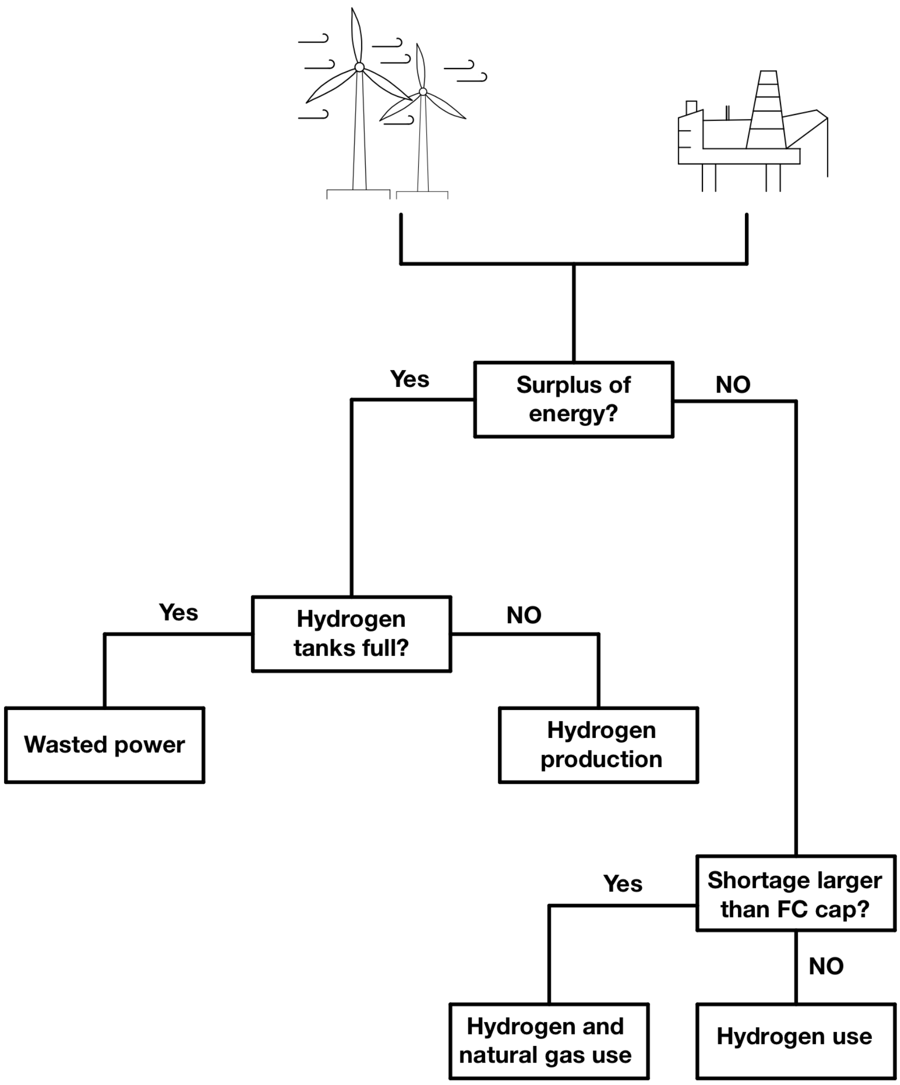

Figure 3.6: Flow chart of hybrid energy backup system.

Like the system in subsection 3.2.4 there will, for every hour, be either a surplus or shortage of power to the platform. Also like the other system, hydrogen will be produced in periods with surplus power if the tanks are not full. However, in periods with shortage of power, both natural gas and hydrogen will be used. A fuel cell capacity between zero and max consumption at the platform will be determined. If the shortage is between zero and the fuel cell limit, the backup power will come from hydrogen. If the shortage of power is greater than the fuel cell limit, a natural gas turbine will together with the fuel cells provide the necessary power.

A set of plots will be made for the tank volume during the 23 years of data available. The tank volume will be calculated as described above, with the same parameters for wind park capacity and hydrogen capacity as in subsection 3.2.4. For each individual plot, a different maximum value for the fuel cells will be used. These plots will then illustrate the effect on the needed storage capacity, using different amounts of natural gas to power the platform.

Plots will also be made to illustrate how much natural gas is used in the different configurations annually compared to running the platform entirely on natural gas.

Cost calculations will not be made in this section of the thesis, but the result will give an indication of reduced cost related to lower storage capacity.

3.6 Comparison of wind farm locations

For the last part of the calculations it is of interest to investigate how placing the projected system at different locations, with different wind resources, affect the outcome. The locations used for the comparison will be locations selected as suitable for wind power by NVE. This section will describe how the locations listed by NVE were picked as well as briefly describing the two areas used in this thesis. Furthermore, this section will explain the parameters which is to be used in the comparison.

3.6.1 NVE Locations

In 2010 NVE published a report on an assignment given by the government to assess which areas along the Norwegian coast which was suited for offshore wind power. The work with the report was based on three areas of interest [72]:

1. Offshore areas which are expected to be most suitable for offshore wind power due to ocean depth, wind resources, power transmission, supply, and market conditions.
2. Fishing areas, shipping, aviation, petroleum business, traveling and military interests.
3. Environmental challenges.

Following the research done by NVE, 15 areas, as shown in Figure 3.7, were listed as possible areas to build offshore wind parks along the Norwegian coast. Among the 15 areas, 4 of them are intended for floating wind turbines, and the other 11 are intended for bottom fixed wind turbines.

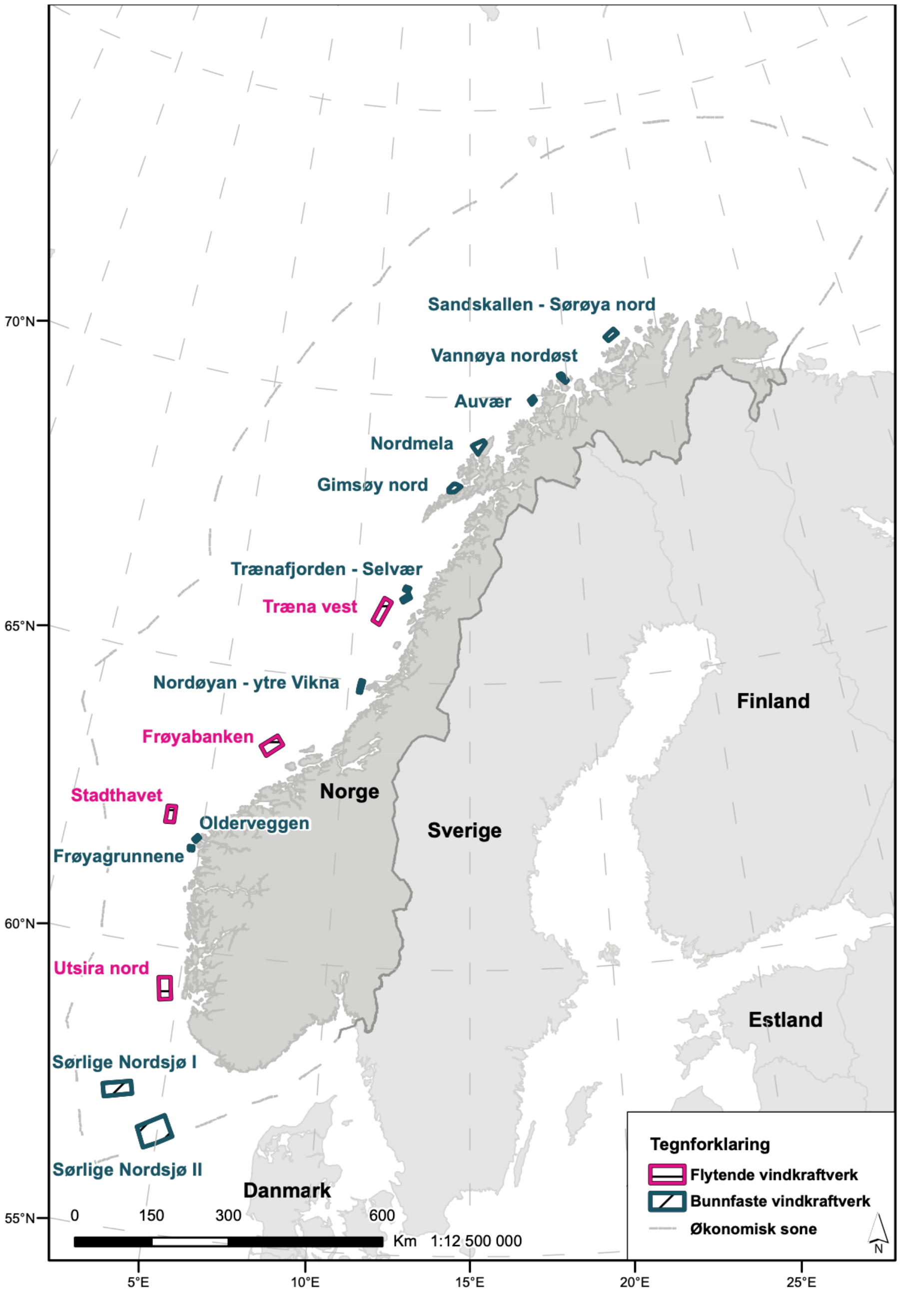

Figure 3.7: Areas suitable for offshore wind power according to NVE. Figure taken with permission from [72].

This thesis will as mentioned utilize data from some of the areas picked by NVE. Given that one of the main objectives in this thesis is to compare several locations with different wind resources to examine the effect on system size and cost, the capacity factor will be essential. The areas chosen will therefore to a high degree be picked based on wind conditions, with a large variation among the areas being beneficial. The areas chosen are Utsira Nord and Gimsøy Nord. As shown in Figure 3.7 Utsira Nord is intended to have floating wind turbines while Gimsøy Nord is intended to have bottom fixed wind turbines. However, in this thesis it is assumed that both locations use the floating 15 MW wind turbine previously used in the thesis.

3.6.2 Parameters for comparison

Given that the system in python will have several possible configurations regarding wind farm and hydrogen system capacity, a set of parameters must be determined to have a way of comparing the locations. The data for the different locations used will therefore be put into the python script created for the wind and hydrogen system in subsection 3.2.4. This means that both locations will use:

- 8 wind turbines with 15 MW capacity
- 600 tonnes of hydrogen storage capacity

By having fixed parameters, it is easier to compare how much capacity must be added for there to be available energy at all times.

Chapter 4

Results

In chapter 3, descriptions of the different calculations have been made in detail. In this chapter of the thesis, the results of the capacity calculations, Monte Carlo simulations, techno-economic analysis, hybrid system calculations and the comparison of different wind farm locations will be presented. The chapter will follow the same structure as chapter 3 to allow for a clearer presentation of the results. Furthermore, this chapter will present the results without discussing the implications.

4.1 Calculating capacity for wind farm and hydrogen system

In this section of the results chapter, the results calculated for the capacity of the wind farm and hydrogen system will be presented. The calculations for available hydrogen will be presented for two different configurations of the energy system. The two different configurations are systems were the number of wind turbines, as well as the amount of hydrogen storage varies. Further, calculations for how well the hydrogen tanks are utilized will be presented, as well as the amount of power which is wasted when the hydrogen tanks are full and there is sufficient wind.

The hydrogen volumes over 23 years were calculated, according to the description in subsection 3.2.4, for a tank capacity of 600 tonnes and 750 tonnes as shown in Figure 4.1 and Figure 4.2. Both configurations have a total round trip efficiency of 36% for the hydrogen backup system. The total round trip efficiency is the product of all the efficiencies used for the hydrogen system listed in Table 3.2. The gross wind power capacity factor for both configurations are 63.6 % based on data from NORA3 as discussed in subsubsection 3.2.1. After including wake losses and availability losses as shown in Equation 3.2 in section 3.2, the net capacity factor is 57.2 % at both.

4.1.1 Configuration 1 - 120 MW wind farm capacity and 600 tonnes of hydrogen storage capacity

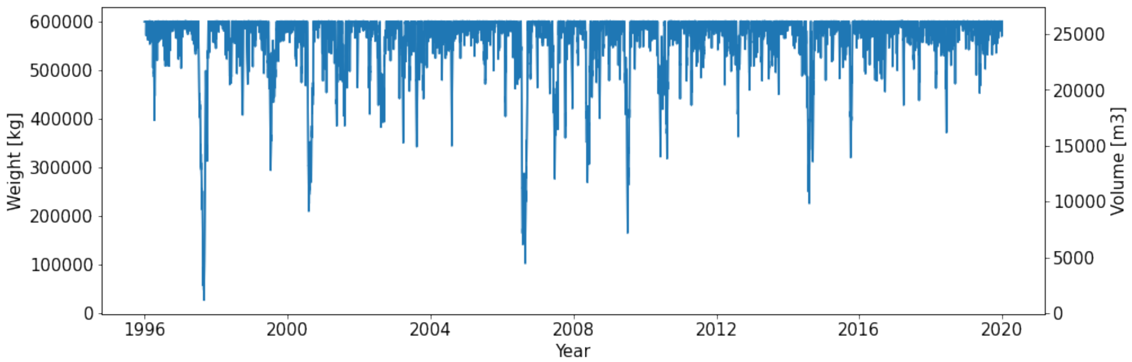

Figure 4.1: Hydrogen available over 23 years with a 120 MW wind farm and a 600 tonne hydrogen tank capacity.

In the first configuration the system utilizes a wind park with 8 wind turbines with 15 MW rated power. This means that the wind park has an installed capacity of 120 MW. The system also uses 600 tonnes of hydrogen storage. As shown in Figure 4.1 this configuration is sufficient for there to be available hydrogen at all times. The lowest value for the tank volume comes in September 1997 with the tank volume being 26.7 tonnes, or 1162 m^3. The plot shows that the amount of hydrogen is for the most part at the hydrogen tank limit. What the plot also shows is that there are large variations in the tank volume during the entire period. By looking closer at the data, the sudden major drops in available hydrogen are found to be around the summer periods.

4.1.2 Configuration 2 - 105 MW wind farm capacity and 750 tonnes of hydrogen storage capacity

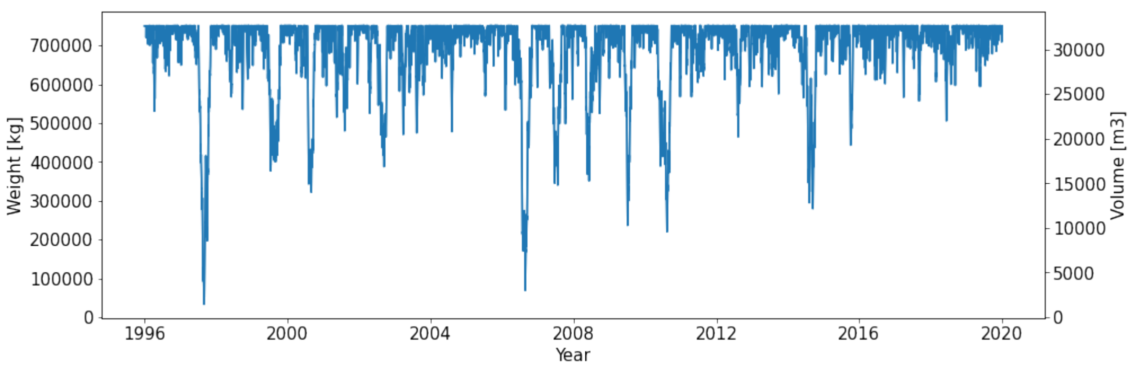

Figure 4.2: Hydrogen available over 23 years with a 105 MW wind farm and a 750 tonne hydrogen tank capacity.

The second configuration utilizes 7 wind turbines with a rated power of 15 MW. This again means that the installed capacity in the wind park is 105 MW. The system also uses 750 tonnes of hydrogen storage. Like the previous example in configuration 1, a wind park with 105 MW installed capacity and a 750 tonne hydrogen storage is sufficient for there to be available power at all times. The lowest value for the tank volume is also in this example in September of 1997, with the tank volume at 33.8 tonnes, or 1469 m^3. As shown in Figure 4.2 there are also large variations in the tank volume in this configuration. The fluctuations appear to be similar to the ones in Figure 4.1 but also appears to have more, and deeper, low points. As for configuration 1, the hydrogen tanks appear to be at the max limit for most of the time, however, less frequently than in Figure 4.1

For the remaining calculations in the thesis, configuration 1 is chosen as the preferred configuration.

4.1.3 Electrolysers and fuel cells

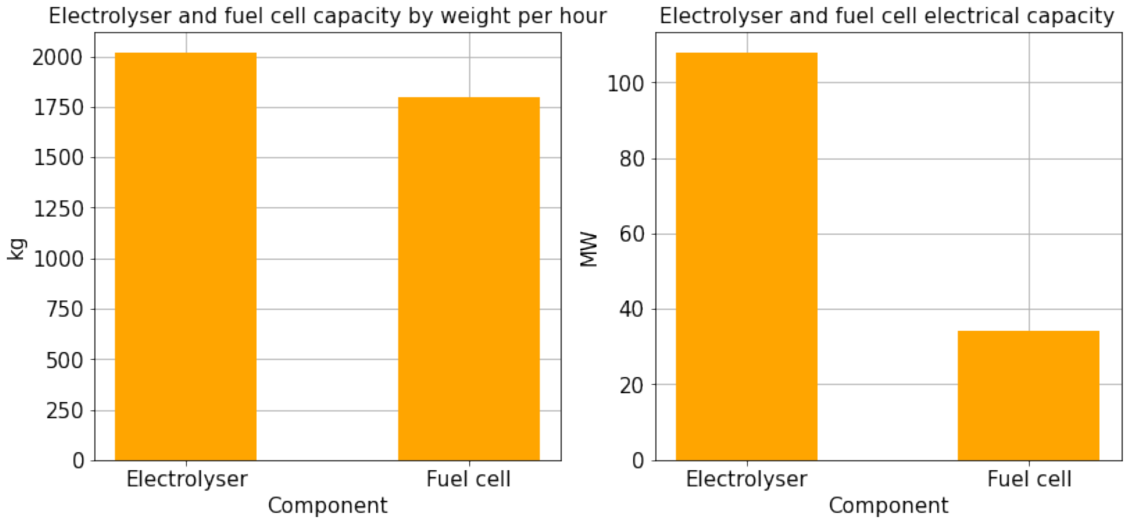

Figure 4.3: Electrolyser and fuel cell capacity given as both hydrogen weight per hour and electrical capacity.

The needed capacity for the electrolysers and fuel cells in configuration 1 are then calculated according to the method described in subsection 3.2.4. As shown in Figure 4.3 it is calculated that the needed capacity for the electrolysers are 2020.8 kg/h, or with the given efficiencies, 108 MW of installed capacity. For the fuel cells, the needed capacity is calculated to be 34 MW and 1794.65 kg/h with efficiencies taken into account. This means that the electrolysers must be able to produce 2020.8 kg of hydrogen per hour at maximum load. It also means that if there is no wind and the fuel cells power the platform on their own, the amount of hydrogen used per hour is 1794.65 kg.

4.1.4 Tank capacity utilisation

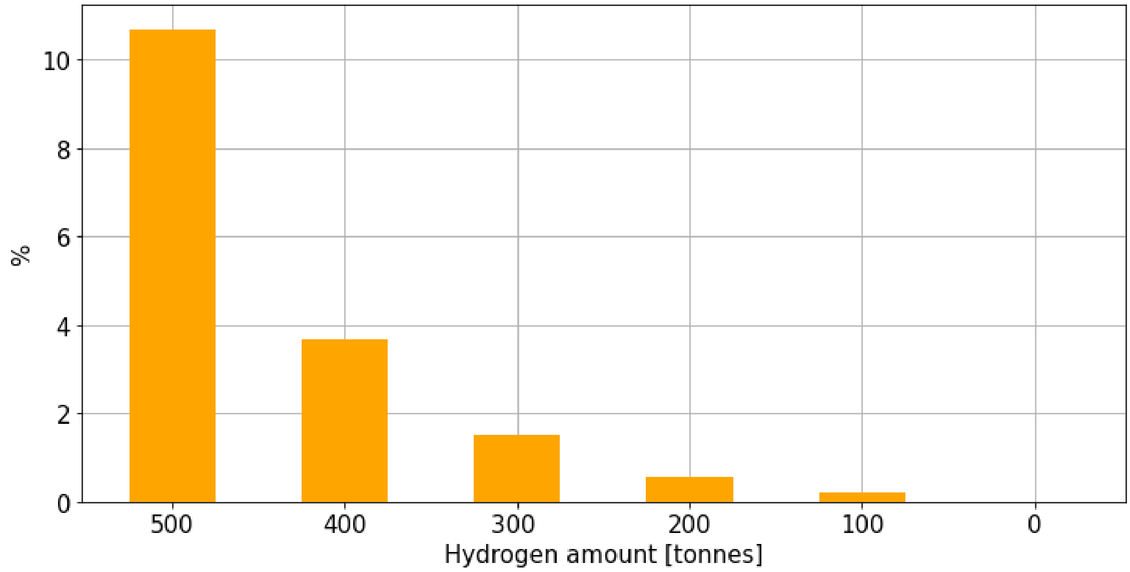

Figure 4.4: Tank volume utilisation. Showing percentage of time the available hydrogen in the tanks is below given limits.

As explained in subsection 3.2.5 calculations were made to investigate how well the tank capacity have been utilised. Figure 4.4 shows the percentage for how much time the tank volume is below certain limits. As shown in the figure the tank volume is only below 500 tonnes for 10.7 % of the time. At 400, 300, 200 and 100 tonnes the percentages are 3.69 %, 1.53 %, 0.55 % and 0.19% respectively. The figure also shows that the tank volume is never below zero.

4.1.5 Wasted power

As described in subsection 3.2.6, power from the wind farm will be wasted in periods where the hydrogen tanks are full and there is a surplus of energy from the wind park. To determine how much energy is wasted on average annually, calculations were made according to the description in subsection 3.2.6. The wasted power, and possible hydrogen production and sales is presented in Table 4.1 below:

Average annual amount of wasted power	0.28 TWh
Possible hydrogen production if wasted power was used to produce hydrogen	5173 tonnes
Potential income from hydrogen sales given a hydrogen price of 45 NOK/kg	232.8 MNOK

Table 4.1: Annual wasted power and the potential for hydrogen production and sale

As shown in Table 4.1 0.28 TWh are wasted on average annually. This amount of energy would, with the chosen efficiency values, be enough to produce 5173 tonnes of hydrogen. This amount of hydrogen equates to 8.6 times the storage capacity in configuration 1. Furthermore, if the energy were to be used for hydrogen production, and the hydrogen had been sold for a price of 45 NOK/kg, this would mean an annual income of 232.8 million NOK.

4.2 Monte Carlo simulations

Due to uncertainties related to both efficiency values for the different components, as well as wind park losses, Monte Carlo simulations were performed according to the method described in section 3.3. The Monte Carlo simulations use random values within a triangular distribution for each parameter. The graphs are plotted below both with, and without, a limit for the hydrogen tanks. The limit is set at 600 tonnes of hydrogen storage.

4.2.1 Varying efficiency values

As mentioned above, Monte Carlo simulations were made for varying efficiency values for the hydrogen system. In the capacity calculations in section 4.1 the total round-trip efficiency was as mentioned 36 %. Figure 4.5 shows a plot of the Monte Carlo simulations as the available amount of hydrogen over 23 years without limitations to the hydrogen tank capacity. In Figure 4.6 there is included a 600 tonne hydrogen tank capacity.

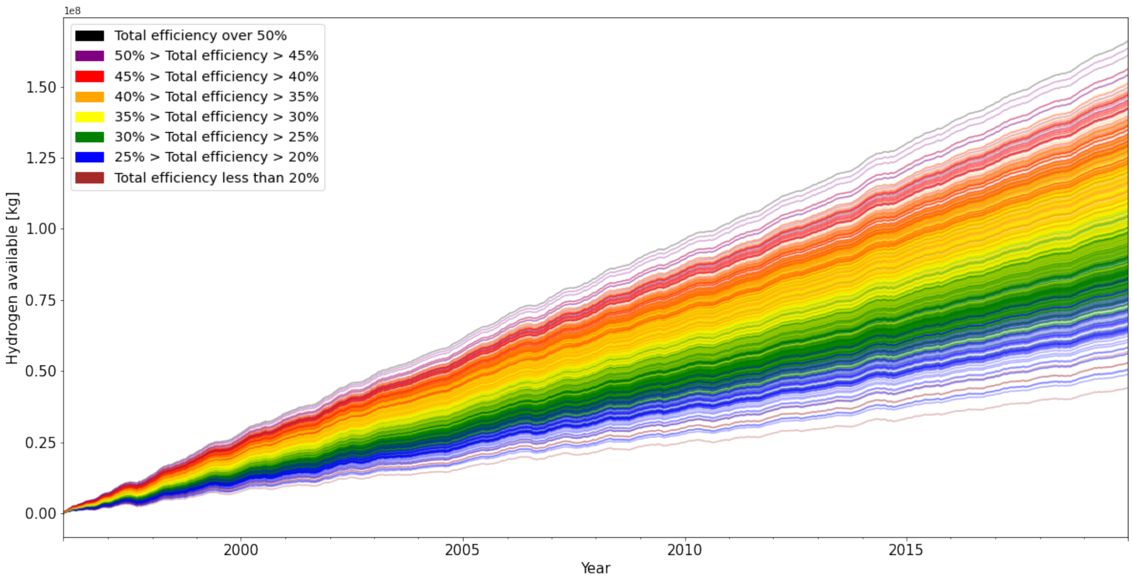

Figure 4.5: Monte Carlo simulation with varying efficiency values, using an infinite hydrogen tank capacity. Y-axis is 1e8.

As shown in Figure 4.5 there is a large spread in available hydrogen at the end of the 23 years of data. The different graphs are as shown in the figure separated by colour according to the total efficiency used for the hydrogen system. There seems to be a clear difference between the different efficiency levels, with the higher values having the largest amount of available hydrogen.

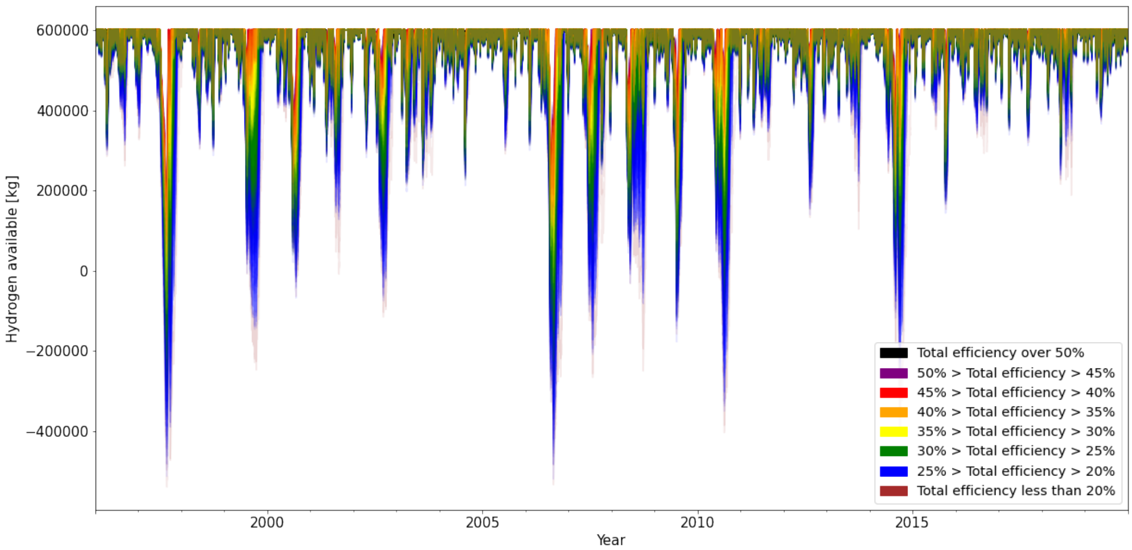

Figure 4.6: Monte Carlo simulation with varying efficiency values, using a 600 tonne hydrogen tank capacity.

Figure 4.6 is plotted with a tank limit of 600 tonnes, and illustrates the effects of having a different total efficiency than in the original capacity calculations. As shown in subsection 4.1.4 the amount of hydrogen available in the hydrogen tanks most often stay between 500 to 600 tonnes. However, from the figure it could be seen that for efficiency levels ranging from 30 % to below 20 % the energy storage is not sufficient for powering the platform. The dips in available hydrogen which could be seen clearly in section 4.1 are deeper with the lowest point being more than 600 tonnes below zero. For efficiency levels in the range of 30 —35 % and upwards, there seems to be sufficient hydrogen.

4.2.2 Varying wind park losses

As for the varying efficiency values, the varying wind park losses have also been used in Monte Carlo simulations. In section 4.1 the total wind park losses was assumed to be 10%. Figure 4.7 shows the Monte Carlo simulation plotted using varying wind park losses, with an infinite hydrogen tank capacity. Figure 4.8 shows the Monte Carlo simulations with a 600 tonne hydrogen tank capacity.

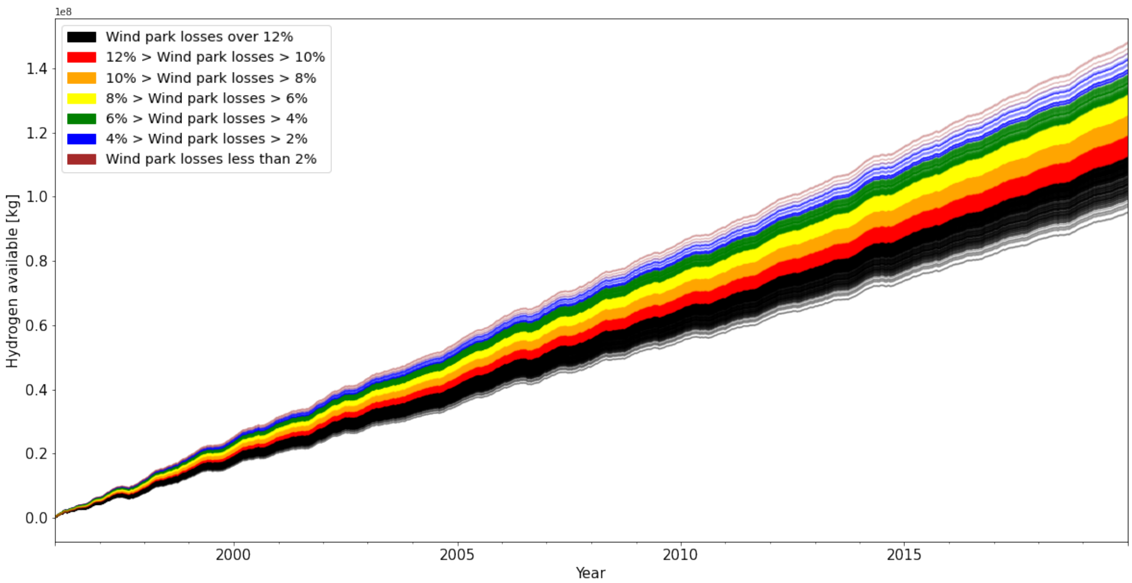

Figure 4.7: Monte Carlo simulation with varying wind park losses, using an infinite hydrogen tank capacity. Y-axis is 1e8.

Similar to the plot with the alternating efficiency values, there is a clear variation between the highest and lowest value for hydrogen available in Figure 4.7. There is also clear separation between the different intervals of wind park losses, with losses beyond 12 % having the lowest amount of hydrogen available.

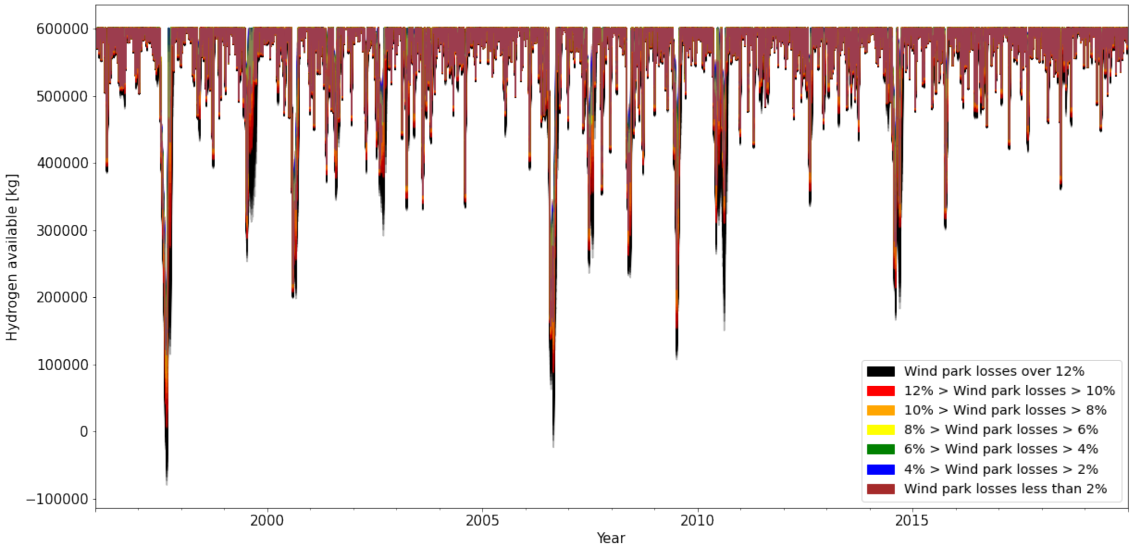

Figure 4.8: Monte Carlo simulation with varying wind park losses, using a 600 tonne hydrogen tank capacity.

Like the original plots in section 4.1, there are dips in the available hydrogen in Figure 4.8. Similar to Figure 4.6 the dips are deeper than for the original calculations. The figure further indicates that wind park losses of above 12 % would lead to insufficient levels of hydrogen at certain points. The lowest point seems to be at around negative 75 tonnes.

4.3 Techno-economic analysis

A techno-economic analysis was performed as described in section 3.4. In this part of the thesis both the investment costs and the net present value was calculated for the years 2020 and 2030.

4.3.1 Investment cost

The investment costs were calculated using the cost parameters in subsection 3.4.1 and are shown in Figure 4.9. Due to the expected drop in costs from 2020 to 2030, the investment costs were calculated for both years.

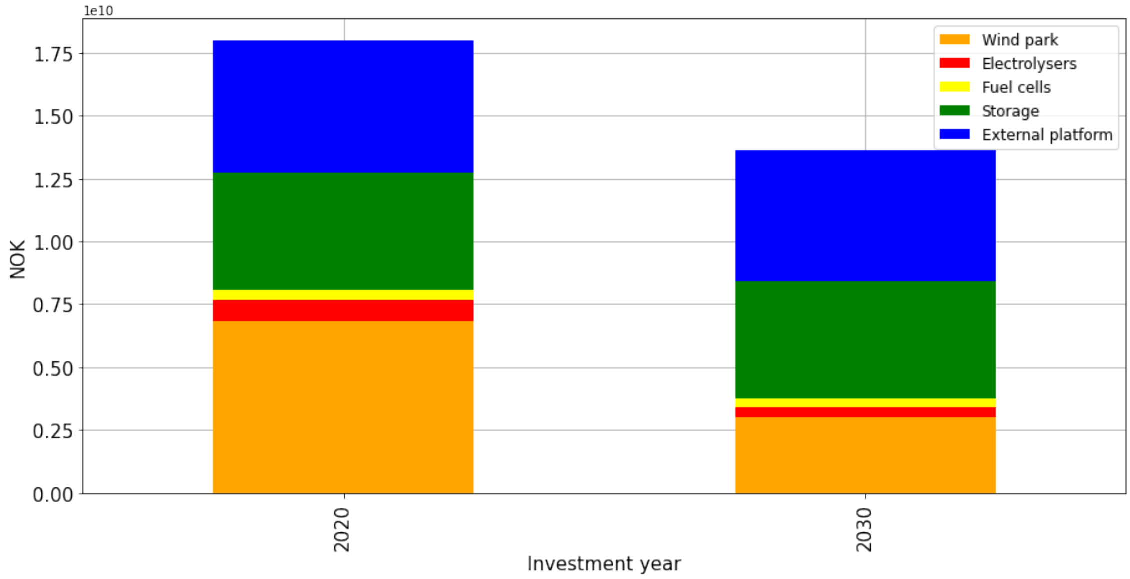

Figure 4.9: Investment costs in 2020 and 2030. Y-axis is 1e10.

The investment costs include the wind park, electrolysers, fuel cells, subsea hydrogen storage and the external platform for the electrolysers and fuel cells. As shown in Figure 4.9, the investment costs have a clear decline from 2020 to 2030. For 2020 the investment costs are calculated to be 18 billion NOK. Within 2030 the costs are calculated to decrease by 24.4 % and are estimated to be around 13.6 billion NOK. The figure also shows that the main cost driver in 2020 is the wind farm followed by the external platform and the hydrogen storage. In 2030 however, the main cost driver is the external platform followed by the hydrogen storage and the wind farm. The figure also shows that the electrolyser and fuel cell systems make out a relatively small part of the total investment.

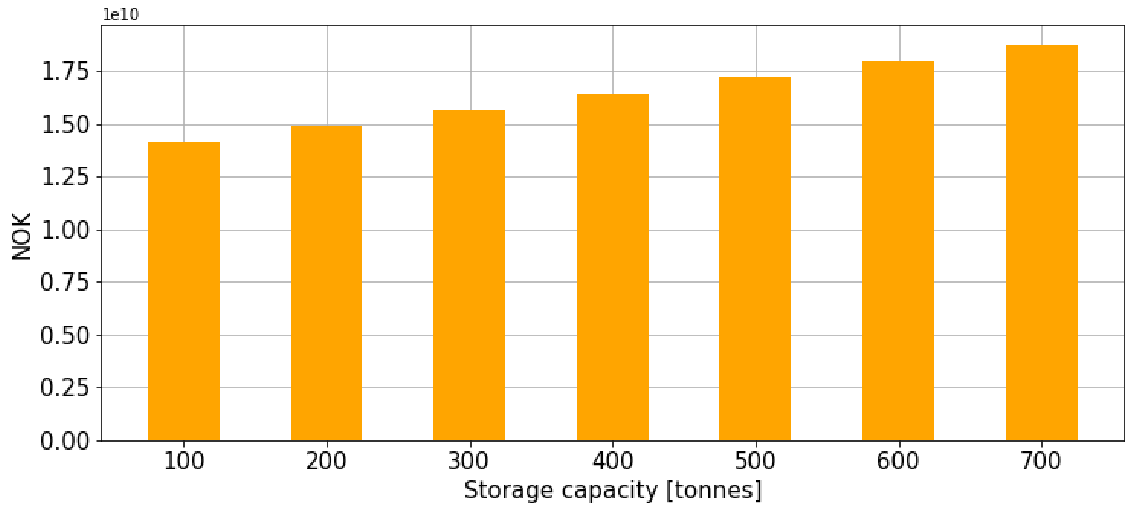

Figure 4.10: Investment cost in 2020 with varying hydrogen storage capacity. Y-axis is 1e10.

In Figure 4.10 the investment cost in 2020 is plotted with a varying hydrogen storage capacity. The investment cost is calculated to be 14.1 billion NOK with 100 tonnes of storage and 18.7 billion NOK with 700 tonnes of storage, with the storage cost being 772,100,000 NOK per 100 tonnes.

4.3.2 Net present value

The net present value (NPV) is calculated according to the description in subsection 3.4.3. All components used are assumed to have a 30 year lifetime.

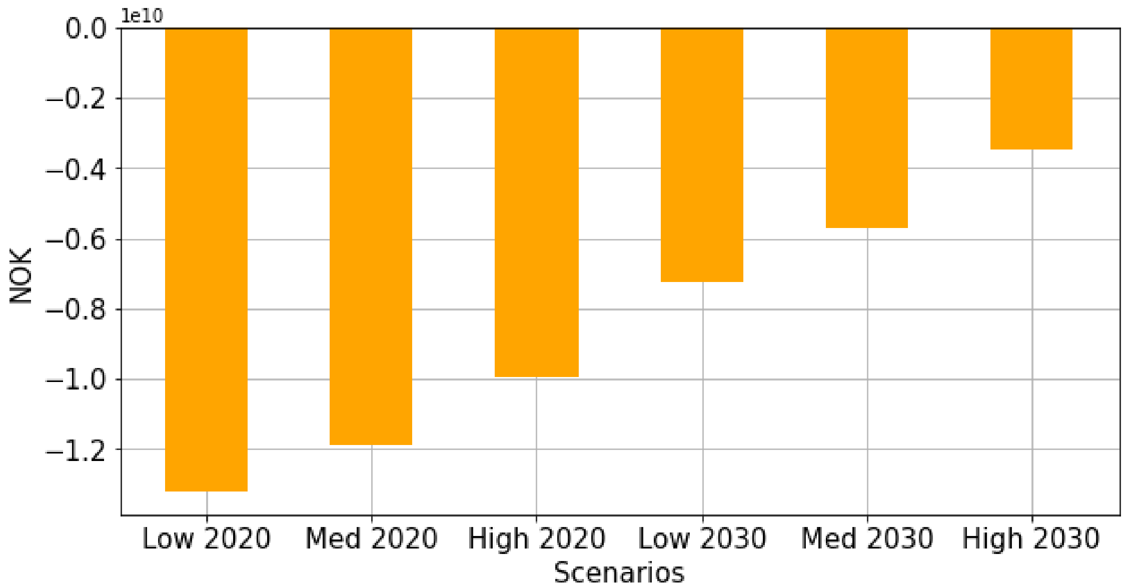

Figure 4.11: Net present value in 2020 and 2030 with discount rates of 8 %, 6 % and 4 %. The "Low", "Med" and "High" scenarios use discount rates of 8%, 6% and 4% respectively. Y-axis is 1e10.

In Figure 4.11 the NPV in 2020 and 2030 have been plotted with a discount rate of 8, 6 and 4% for both years. The calculations implies that the NPV is negative for all scenarios. The 2020 values are calculated to be considerably lower than the values for 2030. The lowest value is for investment in 2020 with a discount rate of 8 %. This scenario has a NPV of negative 13.2 billion NOK. The highest NPV calculated is for investment in 2030 with a 4 % discount rate. For this scenario the NPV is calculated to be negative 3.5 billion NOK.

4.4 Hybrid backup system

As mentioned in section 3.5 the storage of hydrogen is expected to be a major part of the investment cost if a project like the one in this thesis is completed. Because of this the use of a natural gas turbines which is intended to take peak load has been investigated. In this section both the reduction in storage needs, as well as the natural gas usage have been calculated.

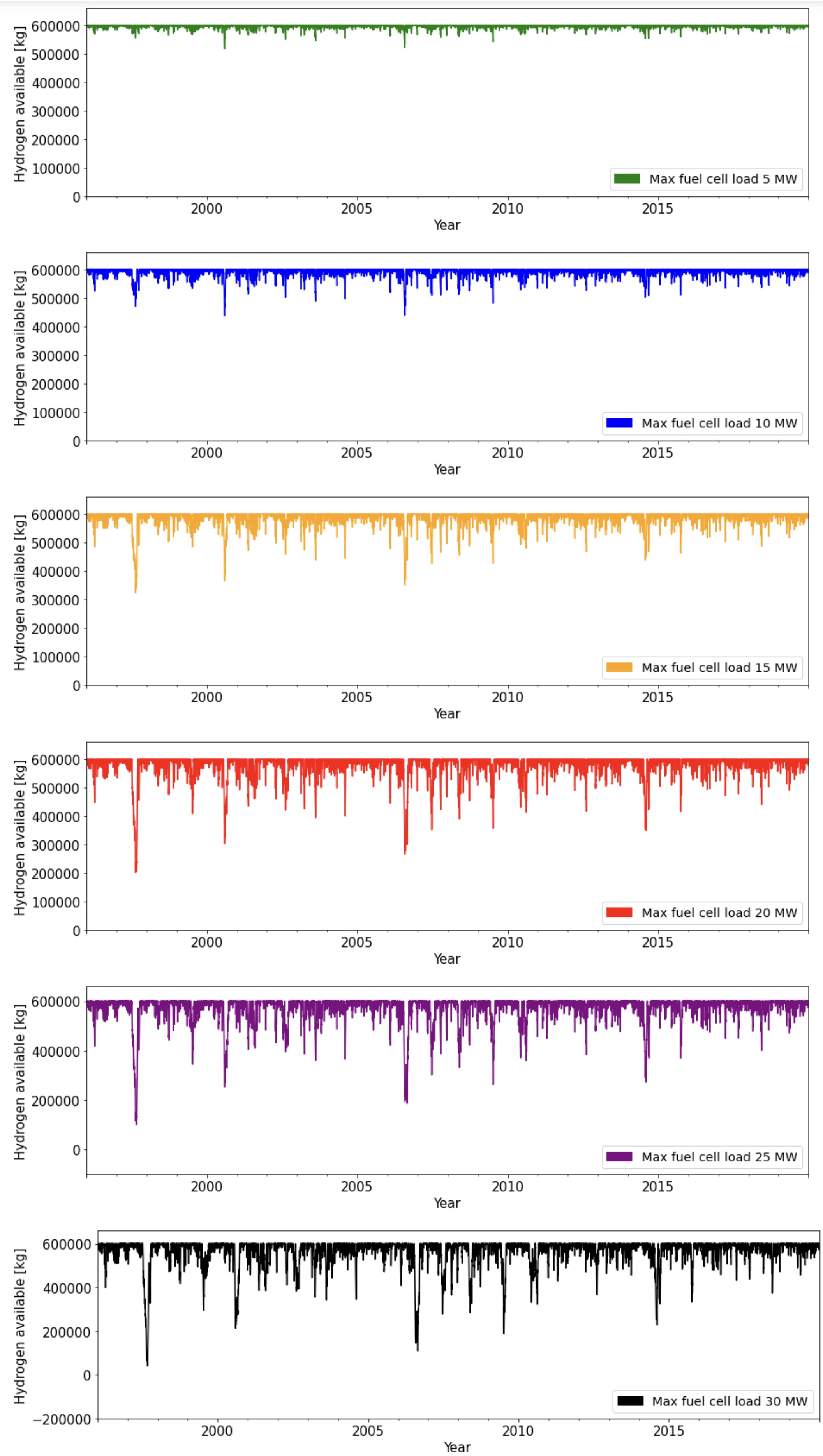

Figure 4.12: Available hydrogen in hybrid backup system with a varying amount of fuel cell capacity.

Figure 4.12 shows the tank volume over 23 years with varying amounts of fuel cell usage. In the bottom right corner of each plot there is a colour and a description which correlates with the plots. Calculations show that the lowest amount of hydrogen available during the 23 years for the configuration with 5 MW of fuel cells is around 517 tonnes. For the other configurations the lowest tank volume is around 438, 322, 201, 100 and 40 tonnes in descending order. These results points to a large decrease in needed storage, given that the capacity of the hydrogen storage have been decided by the lowest amount of hydrogen available. The results also point to a larger reduction in hydrogen storage when going from 20 to 10 MW of fuel cells than when going from 30 to 20 MW of fuel cells. The reduction is also smaller when going from 10 to 5 MW of fuel cells than going from 20 to 15 MW.

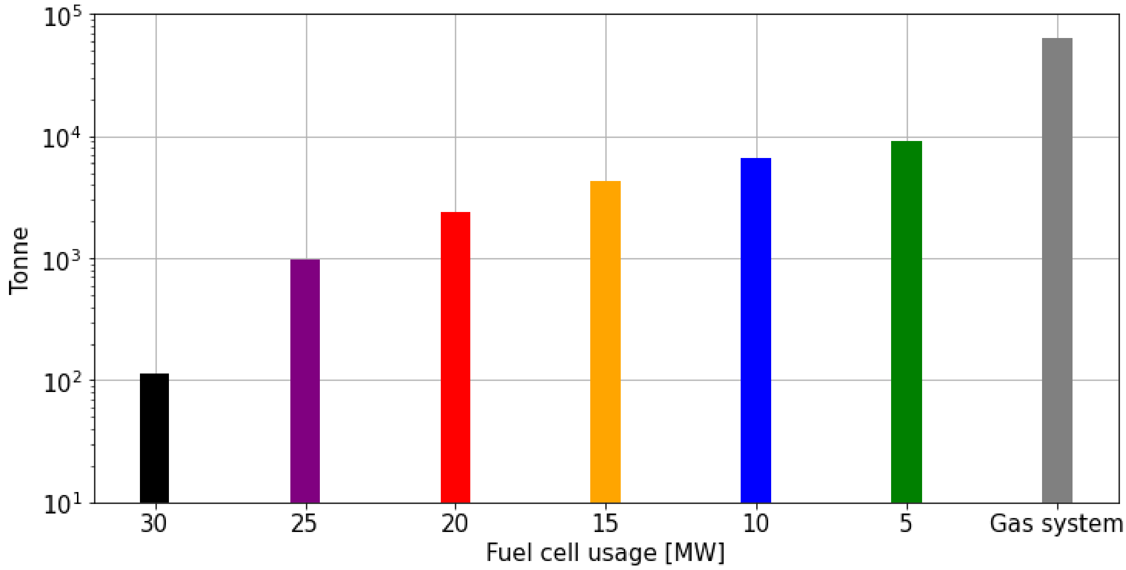

Figure 4.13: Annual natural gas usage with a varying max fuel cell load versus 100 % natural gas usage. Y-axis plotted as log-scale.

The annual amount of natural gas usage in tonnes is plotted in Figure 4.13 with the colours corresponding to the results in Figure 4.12. The results are plotted with a logarithmic y-axis. The grey bar at the right side of the plot illustrates the annual natural gas usage if a platform with the consumption of the one in this thesis were ran entirely on natural gas. Calculations show that if the platform were run entirely on natural gas, it would consume around 64362 tonnes on average every year. For the hybrid systems the annual natural gas use is calculated to be 9159, 6558, 4292, 2403, 971 and 113 tonnes from right to left. This further means that the hybrid systems use 14.2, 10.2, 6.7, 3.7, 1.5 and 0.2 % of the amount of natural gas used in the system entirely run on natural gas, respectively. As explained above, there is a larger reduction in needed hydrogen storage when going from 20 to 10 MW of fuel cells than going from 30 to 20 MW. Figure 4.13 shows the effects of this with the gas usage increasing with 4155 tonnes annually when going from 20 to 10 MW. In contrast the use of natural gas has an increase of 2290 tonnes annually when going from 30 to 20 MW of fuel cells.

4.5 Comparison of wind farm locations

In this part of the chapter, wind data from two of the 15 areas listed by NVE as suitable for offshore wind power have been used to calculate the needed capacity of the energy system. In section 3.6 the locations used in the comparisons are described, together with explanations of the different parameters used. In this section of the thesis the plots of the hydrogen tank contents at Utsira Nord and Gimsøy Nord are shown. Both examples have a 600 tonne hydrogen tank capacity as well as eight, 15 MW wind turbines.

4.5.1 Utsira Nord

The gross capacity factor at Utsira Nord is calculated to be 59.4 %, and the net capacity factor is calculated to be 53.5 %. The calculated hydrogen tank contents are shown in Figure 4.14.

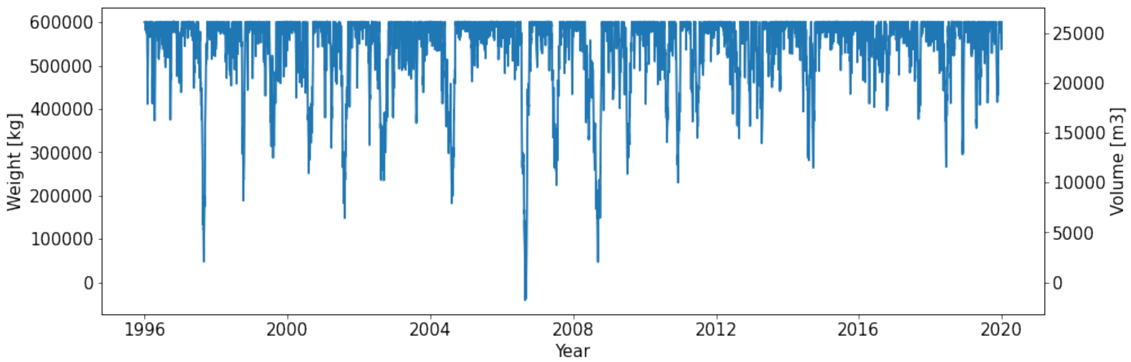

Figure 4.14: Hydrogen volume over 23 years at Utsira Nord with a 120 MW wind farm capacity and 600 tonnes of hydrogen storage.

As shown, there is a dip in the hydrogen tank contents which goes below zero and indicates that the energy storage is not sufficient with the available wind data. The lowest point shows a shortage of hydrogen of 41.3 tonnes, or 1796 m^3. However, from the graph it can be seen that the tank volume is at the max limit for a large period of time. Further analyses show that by increasing the number of wind turbines from 8 to 9, the hydrogen available would have a minimum value of 43.4 tonnes, which then points to the energy storage being sufficient.

4.5.2 Gimsøy Nord

The gross capacity factor at Gimsøy Nord is calculated to be 46.8 % with the net capacity factor calculated to be 42.1 %. Figure 4.15 shows the plotted hydrogen volume available.

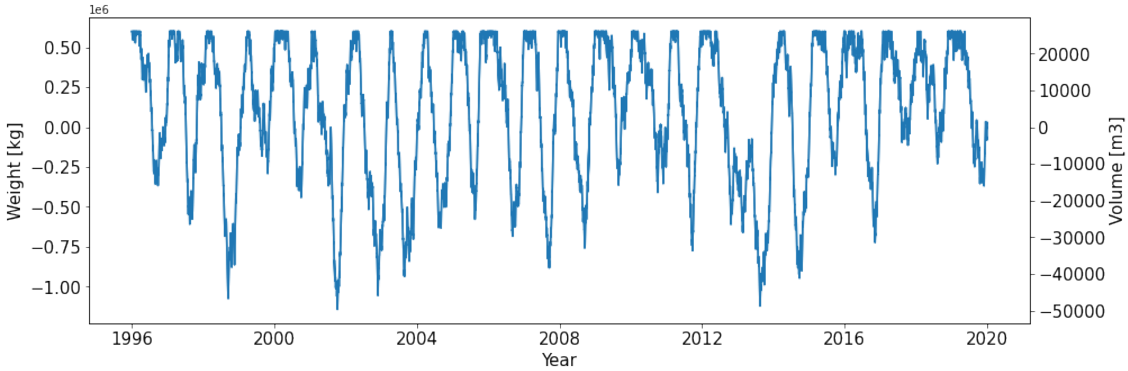

Figure 4.15: Hydrogen volume over 23 years at Gimsøy Nord with a 105 MW wind farm capacity and 750 tonnes of hydrogen storage. Left y-axis is 1e6.

The figure points to the hydrogen system being clearly insufficient. Large dips are in long periods below zero. The lowest point in the graph is at negative 1142 tonnes, or 49652 m^3. Unlike in Figure 4.14 where the hydrogen volume is mostly at max, the hydrogen volume in Figure 4.15 is rarely at the maximum level. Further analyses show that for there to always be hydrogen available with a 600 tonne tank capacity, 16 wind turbines is necessary. With 16 wind turbines the minimum hydrogen amount available is 7.4 tonnes of hydrogen.

Chapter 5

Discussion

As explained in the introduction in chapter 1, oil and gas platforms on Norwegian soil are one of the largest emitters of climate gases in the country. The emissions equate to around 27% of the total climate gas emissions in Norway. Due to this, plans are being worked on to use electricity to power these platforms instead of the natural gas turbines which are used today. The way many of the platforms are intended to be electrified are with power cables from the grid at mainland. The projected increase in electricity cost coming from this electrification has made it interesting to look at other ways of electrifying the platforms. One of the theoretical ways this could be done is by utilising wind power and some sort of energy storage. This thesis has looked at possibilities of utilising offshore wind power together with hydrogen to power these platforms. The goals of this thesis have been to investigate:

1. if it is possible to power oil and gas platforms with wind power and hydrogen, and to find out what capacity for both the wind farm and hydrogen system is needed to do so.
2. how different efficiency values as well as wind park losses affect the capacity requirements.
3. what the total investment cost and net present value is for the power system.
4. if it is possible to utilise a hybrid backup system to reduce size and cost of the hydrogen system.
5. how different locations, with different capacity factors at the wind park, affect the results and feasibility of such a project.

In this chapter of the thesis all the key findings will be displayed and interpreted. The limitations of the research will also be discussed as well as how the research can be implemented and worked on in the future.

5.1 Interpretation of key findings

5.1.1 Capacity calculations for wind farm and hydrogen system

In section 4.1 the capacity of the wind farm and hydrogen system were displayed with the location of the wind farm being the Gullfaks field in the northern part of the North Sea. Two different configurations of wind and hydrogen systems were made, which both proved to be sufficient. Configuration 1 utilised 8, 15 MW, wind turbines as well as a 600 tonne storage capacity. Configuration 2 utilised 7, 15 MW, wind turbines combined with an increased storage capacity of 750 tonnes. Lowest amount of hydrogen available for the two configurations were calculated to be 26.7 and 33.8 tonnes, respectively. The capacity for the electrolysers and fuel cells were then calculated for configuration 1. The results pointed to a capacity of 108 MW for the electrolysers and 34 MW for the fuel cells being necessary.

The capacity of the wind farm and hydrogen system have been decided by looking at the amount of hydrogen available at all times during the 23 year period. The total energy system including the wind farm and hydrogen system is rated as sufficient if there is available hydrogen at all times. If the hydrogen level goes below zero at some point, it means that there is insufficient energy in the system at that point, which again means that the energy backup system is insufficient. However, this thesis utilises wind data from 23 years to assess the needed capacity. It is uncertain how the calculations would look if a larger period of time was used, but it is not regarded as unlikely that there could be periods were the dips in the available hydrogen are even deeper. Due to this it is not possible to determine with absolute certainty that the capacity of the energy system used in this thesis would be sufficient. Furthermore, the capacity of the wind farm and hydrogen storage system is then to a large degree decided by the dips in the hydrogen volume, since there needs to be hydrogen available at all times. This could lead to an excessive hydrogen tank volume, which will be utilised ineffectively as the large dips only account for a small part of the time. Given that both the system configurations mentioned above proved to be sufficient, a clear answer on the most favourable configuration could be hard to determine. The favourable configuration could rather depend on factors such as price of components, effect on surrounding environment, footprint and so on. The capacity for the electrolysers are a result of the maximum surplus of energy calculated. This is because it ensures that all of the surplus power is utilised in order to reduce the storage needs. The capacity of the fuel cells is 34 MW because this is the peak consumption at the platform. The fuel cells need to be able to power the platform on their own in periods were there are no wind, and the wind park does not produce any power. Given that this thesis uses hourly data it is assumed that the fuel cells could deliver necessary power at all times. However, the fuel cells have a ramp up time which will vary depending on the technology used. It is therefore possible that batteries or capacitors would be needed for instant power in case of sudden drops in wind speed and quick alterations in produced power.

Given the large capacity of the hydrogen storage, it was of interest to find out the percentage of time the hydrogen volume is below certain tank limits. Calculations were made for configuration 1 which has a 120 MW wind farm capacity and 600 tonne hydrogen storage. Results showed that in configuration 1 the hydrogen volume was below 500, 400, 300, 200 and 100 tonnes for 10.7, 3.69, 1.53, 0.55 and 0.19 % of the time, respectively. This further implies that the tank volume generally will be between 500 tonnes and max capacity at 600 tonnes.

As mentioned previously, the tank volume could be excessive for most of the time if it is to be decided based on the major dips in the hydrogen volume. The results above further illustrate this with calculations showing that the hydrogen volume is between 500 tonnes and the max limit of 600 tonnes for 89.3 % of the time. Given the price of hydrogen storage of 772,100,00 NOK/100 tonnes, this means that an extra storage tank capacity of 500 tonnes, costing 3.86 billion NOK is not necessary for 89.3 % of the time.

As shown, the hydrogen volume will often be close to the max limit. In periods where the hydrogen volume is at max limit and the wind conditions are good enough to have a surplus of energy, the energy will be wasted. Calculations were made to investigate how much energy is wasted on average annually due to this. The results showed that 0.28 TWh were wasted. If this wasted energy was used to produce hydrogen it would be possible to produce 5173 tonnes of hydrogen on average annually. Furthermore, if the hydrogen were to be sold for 45 NOK/kg, that could give a yearly income of 232.8 MNOK.

These results indicate that to increase the feasibility of a project like this, the hydrogen infrastructure both onshore, and offshore, would need to improve. Given that there are few ways of selling the hydrogen which could be produced, a large source of income is not utilised. As shown, the major dips in available hydrogen occurs around the summer period. If a system was implemented for selling hydrogen when there is a large surplus, and buying hydrogen in the periods where the wind conditions are poor, the feasibility of the project could improve. Ways of selling and buying hydrogen could potentially include ships or piping to the mainland as mentioned in [9]. Another alternative for better utilisation could be if several platforms in a cluster were electrified using this system like in [8]. This could enable purchase and sale of hydrogen between platforms depending on individual needs. The introduction of hydrogen sales would also reduce the needed storage capacity given that less hydrogen would need to be stored during the periods where the wind conditions are good. This could drastically reduce the cost of the project.

5.1.2 Monte Carlo simulations

Due to the large intervals in the numbers for efficiency and wind park losses it was of interest to investigate how varying the efficiencies and wind park losses would affect the results. Monte Carlo simulations were made to investigate this. The Monte Carlo simulations were conducted by making plots with 1000 graphs, were each graph used random values within an interval for efficiency and wind losses. Both scenarios were plotted both with, and without, a hydrogen tank limit of 600 tonnes. For the calculations with variations in the efficiency values the results pointed to a large variation in hydrogen volume available. The plot without tank limit showed a large spread at the end of the 23 years. For the plot with a tank limit, the results indicated that a total efficiency for the hydrogen system below 30 % would make the energy system insufficient. A total efficiency below 20 % gave a minimum value in the hydrogen volume of below negative 600 tonnes. For the plots with the varying wind park losses there were also a clear separation between the lowest and highest values. When plotted with a 600 tonne tank limit, the results pointed to wind park losses above 12 % giving insufficient hydrogen values.

These results illustrate the dependence on efficiency and wind loss values. In chapter 2 the efficiency of several of the components used were presented with an interval. This is because different technologies for the various components needed have varying efficiency values. Also, the same technologies could have different efficiency values depending on the manufacturer. For the wind park losses, the values depend largely on size of wind farm, location, and weather conditions. The wind park used in this thesis is relatively small and would therefore have relatively small wake losses. For larger wind parks for instance in the region of 1-2 GW the wake losses would be larger. The availability losses would also be affected by weather conditions and placement of wind park as some conditions would make it hard to conduct maintenance and would also ad wear on the wind turbines. Both the varying efficiency values and the varying wind park losses have a significant effect on the necessary capacity for the wind park and hydrogen system. An increase in efficiency and a reduction of wind park losses would reduce the necessary capacity, and a decrease of efficiency and increase of wind park losses would have the opposite effect.

5.1.3 Techno-economic analysis

A techno-economic analysis was conducted to estimate the cost and possible profitability of such a project. Both the investment cost in 2020 and 2030 was calculated, as well as the net present value (NPV) in both years, with 3 different discount rates. Investment costs included the offshore floating wind park, electrolysers, fuel cells, subsea hydrogen storage and an external platform where the electrolysers and fuel cells were to be placed. The investment cost in 2020 were calculated to be 18 billion NOK. From 2020 to 2030 the investment cost were calculated to drop by 24.4 % to a price of 13.6 billion NOK. The calculations also showed that while the wind park was the largest cost driver in 2020, the external platform was the largest cost driver in 2030. The hydrogen storage was the third largest cost driver in 2020, while it was the second largest in 2030. The calculations of net present value showed that all scenarios returned a negative NPV. The highest NPV was for investment in 2030 with a 4 % discount rate. This gave a NPV of negative 3.5 billion NOK. For investment in 2020 with an 8 % discount rate the NPV was calculated to be negative 13.2 billion NOK.

Like for the efficiency values used previously, the cost of the various components varies to a high degree. There are therefore major uncertainties connected with the cost estimates. Some of the cost estimates like the hydrogen storage and the external platform are not presented with two different values for 2020 and 2030 like the other components due to a lack of references. This means that unlike the wind farm, the hydrogen storage does not have a price reduction from 2020 to 2030, which makes it the second largest part of the investment cost in 2030. As mentioned, there is a high level of uncertainty connected with the cost estimates. The external platform is a prime example of this. [38] estimates a price of 1.74 MNOK per MW of electrolysers placed on a floater while [25] estimates a price of 36.9 MNOK per MW of electrolysers placed on a platform. This means that depending on the estimate used, the external platform could either be the largest part of the investment cost in 2030, or a relatively small part. For the electrolysers and fuel cells different prices for 2020 and 2030 were used with both using 2 % of CAPEX as OPEX. In this thesis it is expected that all the components have a lifetime of 30 years. This includes the electrolysers and fuel cells which have a lifetime which varies to a high degree as shown in section 2.4. The lifetime of these components is given as hours of operation. Since the electrolysers only operate when there is a surplus of power, and the tanks are not full they will only operate for relatively small periods of time. The same situation applies for the fuel cells which only operates in periods where there is insufficient wind power. It is therefore uncertain if the electrolysers and fuel cells would need replacement during the 30 years. Further, it is assumed that the electrolysers and fuel cells can operate on 100 % load. Running them on full load will reduce the efficiency, which could make it preferable to have a larger capacity for both components to run them on a lower load. This is however not taken into account in this thesis. The cost estimates also only include the components listed in Table 3.3. Given that additional components are needed for a real life project, the actual price is expected to be higher.

For the net present value, both the sale of the natural gas not used as well as saved expenses regarding CO2 cost were regarded as income. The values for the natural gas price were estimated as a linear increase for the long term using estimates for a shorter term. The values for natural gas are also uncertain given that there are a lot of factors which affect the price. The total CO2 cost is expected to increase to 2000 NOK/kg in Norway in 2030. After 2030 there are no announced plans, which makes it hard to predict. The CO2 tax was therefor made as a linear increase until 2030, with a fixed value of 2000 NOK/kg after 2030. If the tax continues to rise beyond 2030, the savings would be larger, which would increase the NPV. There is also a tax on NOX emissions as mentioned in section 2.5. This is however not taken into account in this thesis but would represent another saving for this project. Another aspect in the NPV calculations is the tax write of mentioned in section 2.5. Since the Hywind Tampen project is regarded as a modification on the existing offshore structure, it gets tax benefits. 78 % of the expenses could be written off the tax bill. If the same conditions apply to a system like the one in this thesis, this could further reduce the cost and improve the NPV. It is however uncertain how these rules would apply given that the system in this thesis is not the same as Hywind Tampen.

5.1.4 Hybrid backup system

As described, calculations show that the hydrogen storage tanks are overdimensioned for most of the time, and the amount of hydrogen is only below 500 tonnes for around 10 % of the time. Due to this, it was of interest to investigate a method for reducing the amount of hydrogen storage needed. The major dips in the hydrogen storage comes as mentioned around the summer periods when there is little wind. However, most often there is some wind, and the fuel cells engage only to fill the gap between the consumption and the production. In the periods where there is close to no wind at all the system uses a lot of hydrogen. Due to this a hybrid backup system was made, where a gas turbine takes the peak load in periods where there is very little wind. The system was tested with 5, 10, 15, 20, 25 and 30 MW of fuel cells, with the remaining shortage being covered by a gas turbine. The amount of natural gas used was calculated to be 14.2, 10.2, 6.7, 3.7, 1.5 and 0.2 % of the amount of gas used if the platform were run entirely on gas. This use of a gas turbine ensured that with a 600 tonne tank capacity, the lowest amount of hydrogen in the tanks were 517, 438, 322, 201, 100 and 40 tonnes. These results points to a major reduction in the need for hydrogen storage, with a relatively small amount of natural gas use.

The hybrid backup system was made so that the fuel cells cover the shortage of energy up to a certain limit. When the shortage goes beyond that limit, the gas turbine covers the remaining shortage. This way of utilising the gas turbine is only one of several ways this could be done. It is likely that the hydrogen storage needs could be further decreased by using the gas turbine in different ways, such as engaging it earlier, or use it combined with the fuel cells immediately when there is a shortage of power. In addition to reducing the need for storage, this solution also reduces the need for fuel cells. This would mean lower CAPEX and OPEX for the fuel cells, but also for the platform where the fuel cells would be located. As shown previously, the platform is the main cost driver with investment in 2030 and it would therefore be beneficial to reduce its size. In this thesis the costs related to the project was calculated for the system which was powered entirely from wind power and hydrogen. Such a system would have zero emissions locally and would therefore not pay a CO2 tax as mentioned previously. By utilising a gas turbine for the peak loads, the system would release CO2 into the atmosphere, which would mean the equivalent CO2 taxes would have to be paid. This would then lead to more expenditures. For the original system, the sale of the natural gas which would have been used, are also listed as income. Using a portion of this natural gas would also lead to lower income. Another aspect is the natural gas turbine used. Depending on the amount of fuel cell capacity in the system, the load on the natural gas turbines would also vary. Since maximum efficiency is usually reached at a certain percentage of load, the natural gas turbines could need to be exchanged for smaller ones with a lower capacity.

5.1.5 Comparison of wind farm locations

Given that a system like the one in this thesis, which is entirely run by wind power and hydrogen, is off grid means that the necessary capacities will be affected by the wind conditions. To understand how much of an impact varying wind conditions and the capacity factor makes, the system was tested at 2 additional locations. The original calculations used, as previously mentioned, wind data from the Gullfaks field with a gross and net wind power capacity factor of 63.6 % and 57.2 % respectively. In this part of the thesis two of the 15 locations presented by NVE as suitable locations for offshore wind power, were used for the calculations. The two locations were Utsira Nord and Gimsøy Nord. Both locations utilised 8, 15 MW wind turbines and 600 tonnes of hydrogen storage. Calculations showed that Utsira Nord had a gross capacity factor of 59.4 %, with the net being 53.5 %. The gross capacity factor was then 4.2 % lower than for the Gullfaks field. When the graph of the hydrogen content was plotted it showed that the energy system was insufficient and that the lowest amount of hydrogen was negative 41.3 tonnes. The calculations also showed that if an extra turbine was added, the system would have been sufficient. Calculations at Gimsøy Nord showed a gross capacity factor of 46.8 % with the net being 42.1 %. This means a gross capacity factor 16.8 % lower than the Gullfaks field. With these conditions the system was insufficient with the lowest point of the hydrogen volume at negative 1142 tonnes. For the system to be sufficient by only adding wind turbines, 8 wind turbines would need to be added, taking the number of turbines from 8 to 16.

The calculations in this part of the thesis shows how vulnerable the system is for varying wind conditions. For Utsira Nord the system would need an extra wind turbine, which with the current price, would mean an increased cost of around 855 MNOK. For Gimsøy Nord the extra cost of wind turbines with today's prices would be around 6840 MNOK. However, as shown in section 4.1, a possible solution could also be to increase the hydrogen storage capacity, as opposed to simply increasing the number of turbines. This solution is expected to be the more favourable option for Utsira Nord, as the shortage of available hydrogen was relatively small. However, for Gimsøy Nord the shortage of hydrogen was substantial. Due to this, more wind power would be needed so an increase in both the number of wind turbines and an increase in storage could be a solution. The results above suggests that if platforms are to be electrified, a solution involving wind power and hydrogen could be location dependent. This means that depending on other ways of electrifying a platform such as with power cables from the mainland, this solution could be favourable at certain locations. Another factor in these calculations is that Gimsøy Nord was described by NVE as suitable for bottom-fixed wind turbines. This is opposed to Utsira Nord which is meant for floating wind turbines. Using bottom-fixed wind turbines compared to floating wind turbines gives a large decrease in investment costs as mentioned in chapter 2.

5.2 Limitations of research

During the calculations made in this thesis several assumptions and estimates have been made, which opens up the possibilities for potential errors. One of the potential limitations in this thesis are the datasets. For the wind data for instance, the NORA3 dataset have been used. The dataset contained 23 years of data at the time of writing. This means that even though the system is intended to operate for 30 years, only 23 years have been looked at. Given that the capacity for the wind farm and hydrogen system is largely decided by the amount of hydrogen available at all times this could lead to inaccurate results. As shown in section 4.1 major dips in the available hydrogen appear sporadically during some summer periods. These dips have a significant effect on the needed capacities. As also shown in section 4.1 the biggest dip during the 23 years at Gullfaks came in the summer period of 1997. If fewer years had been included in the calculations, the system would as a consequence appeared to have a lower capacity need. Furthermore, if more years were available and included, it is possible that even larger dips would have been discovered. Due to this, a larger dataset containing more years of data should have been used. Alternatively, extreme value analysis could have been performed to get more solid results and reduce uncertainty regarding the capacity needs. The dataset for platform consumption should also have included more years given that only 13 months of data was available. After conversations with Lundin Energy which provided the data however, it is assumed that the data received is a good representation of a normal consumption year.

Another important aspect with the calculated results is the uncertainty regarding prices. The prices used in this thesis have been picked after presenting information about price intervals in chapter 2. This means that depending on several factors the prices could be different than the ones chosen in this thesis. For the offshore wind park for instance, the price presented are highly uncertain given the low volume of floating wind turbines produced. Hywind Tampen with its relatively modest capacity of 88 MW is intended to be the largest floating wind farm in the world. Given the completion of larger projects in the future these prices could look different. For the NPV calculations, it was assumed that all components had a lifetime of 30 years. It is regarded as unlikely that this would be a realistic assumption with today's technology. As mentioned previously, the tax write of which benefited Hywind Tampen and which was explained in section 2.5 was not taken into account. If this were to be taken into account, it would likely have a substantial effect on the NPV.

Lastly, this thesis assumes that the electricity demand at the platform is the same as it is at present time when it is run on natural gas. However, the natural gas turbine produces a lot of heat which is utilised at the platform. If the platform is to be electrified using wind power and hydrogen this heat will need to be replaced. Given the relatively low operating temperature of the PEM fuel cells and alkaline electrolysers used in this thesis it is unlikely that they can deliver the required heat. As mentioned in section 2.4 SOFC has a much higher operating temperature and could provide a possible solution. It is however likely that the heat must be generated using electricity, which would increase electricity demand and further increase capacity requirements.

5.3 Implementation and future work

As explained in section 2.5, there is a major difference between building a wind farm which is connected to the grid at mainland compared to if it is only connected to a platform. The fact that the need for a licensing round and licensing applications disappears if there is no connection to the grid, means that the implementation of systems like the one in this thesis could be done quicker. As mentioned in section 2.3, further development is needed to reduce prices for offshore wind. If projects like this could be implemented quicker than wind farms connected to the grid, they could potentially be an important factor in reducing prices. Given the beneficial tax arrangements as previously mentioned and potential support from Enova, the financial feasibility could also improve.

Due to the results suggesting that a solution of using only wind power and hydrogen would be inefficient and expensive, the solution using gas turbines for peak shaving should be investigated deeper. Different usage of the gas turbine could further reduce needed hydrogen storage and drive down cost. Another possibility for future work is to investigate export and import of hydrogen as mentioned previously. If the wasted power could be utilised better by selling excess hydrogen this could generate income. Lastly, investigating implementation of a system like this for a cluster of oil and gas platforms should be investigated. Given that the wind park in this thesis has a capacity of 120 MW, it could potentially run up to 4 platforms with a 30 MW rated power usage at peak production.

Chapter 6

Conclusion

Two different configurations for the energy system were presented, with both proving to be sufficient over a 23 year period. The first configuration consisted of 8, 15 MW wind turbines and 600 tonnes of hydrogen storage, while the second configuration consisted of 7, 15 MW wind turbines and 750 tonnes of hydrogen storage. Configuration 1 was chosen as the preferred option for the remaining calculations in the thesis. Necessary electrolyser and fuel cell capacity were 108 and 34 MW respectively. Further calculations showed that 1/6 of the available hydrogen storage capacity was sufficient for 89.3 % of the time, indicating that the storage volume was used ineffectively. Calculations showed 0.28 TWh of electricity was wasted on average annually. This electricity could produce 5173 tonnes of hydrogen, giving 232.8 MNOK in income if sold for 45 NOK/kg.

Monte Carlo simulations were performed for varying efficiency values for the hydrogen components and wind losses at the wind park. Results indicated that a total hydrogen system efficiency below 30 % would lead to the system being insufficient. Simulations also indicated that wind park losses above 12 % would lead to the system being insufficient.

A techno-economic analysis indicated investment costs of 18 and 13.6 billion NOK in 2020 and 2030 respectively. The NPV was also calculated for 2020 and 2030 with discount rates of 4, 6 and 8 % and no tax write off. All scenarios returned negative NPV. The highest NPV was calculated for 2030 with 4 % discount rate, giving negative 3.5 billion NOK.

A natural gas turbine was then used for peak power shaving. 6 configurations were made with a 5, 10, 15, 20, 25 and 30 MW fuel cell capacity. This led to minimum hydrogen available being 517, 438, 322, 201, 100 and 40 tonnes respectively, indicating major reductions in needed hydrogen storage. The systems used 14.2, 10.2, 6.7, 3.7, 1.5 and 0.5 % of the natural gas used if all power was to come from natural gas.

The wind power and hydrogen system were tested with data from Utsira Nord and Gimsøy Nord with the two having gross capacity factors of 59.4 % and 46.8 % respectively. Calculations at both locations showed that using 8, 15 MW wind turbines and 600 tonnes of hydrogen storage were insufficient. If the systems were to be made sufficient by only adding wind turbines, Utsira Nord would need 1, while Gimsøy Nord would need 8. This represents additional costs of 855 and 6840 MNOK respectively.

The results indicate that it is possible to use an off-grid system with offshore wind energy and hydrogen to power a platform. However, the system is utilised ineffectively and comes with major costs making it not profitable with the prices available. Results also show that the system is vulnerable for changes in system efficiency and wind park losses, resulting in small alterations giving an insufficient system. Using a natural gas turbine for peak power shaving is shown to drastically reduce the needed hydrogen capacity. The system is also vulnerable to changes in wind conditions, which can make it less suitable at certain locations.

It is further believed that if a system like this is to be implemented, the hydrogen infrastructure should be improved. Having the possibility of exporting to, and importing from, the mainland would reduce capacity needs for the energy system as well as improve income and thereby improving the NPV. Alternatively, there could be clusters of platforms sharing the energy system to better utilize the capacity. Going forward these points should be investigated. Due to the climate crisis the world is facing, systems like this should be researched further given the major emission cuts they could deliver.

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