# Electrification of platforms using a floating wind farm and hydrogen

- A feasibility study

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Bachelor's thesis in Energy technology

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Høgskulen på Vestlandet

# Electrification of platforms using a floating wind farm and hydrogen

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# Preface

This bachelor thesis was written under the Department of Mechanical and Marine Engineering at the Western Norway University of Applied Sciences (WNUAS) at the energy technology program in cooperation with Aker Solutions. The aim of this thesis has been to explore how we can achieve zero-emission oil or gas platforms with floating wind power and hydrogen or ammonia as a storage medium.

We would like to thank our supervisors, associate professor Velaug Myrseth Oltedal, and Dr. Jim Stian Olsen from Aker Solutions, for exemplary help and guidance through this exiting project. Furthermore, we would like to acknowledge several people with whom we have had interesting discussions with and whom have supplied us with information; Johan Sandberg, Egil Hystad, Marius Bjørn, Jon Eriksen and Jan Bartl. In addition to this, we would like to use the opportunity to present gratitude towards Knut Vassbotn, who started the process that resulted in us having a good collaboration with Aker Solutions. Lastly, we would like to thank our families for their support through this process.

# Abstract

This thesis is a feasibility study which is assigned to investigate the possibilities of using a floating wind farm linked with hydrogen or ammonia to power an offshore platform. The platform in question is a hypothetical platform with a fixed power demand of 40 MW. The floating wind farm will power the platform, and in periods of overproduction the excess power will produce hydrogen or ammonia, which again will power the platform when there is a shortage of wind.

The thesis will analyse what the gaps in technology are and find the cost drivers for such a project.

Calculations showed a need for 170 and 220 MW of wind power, and storage capacity of 1200 and 9500 tonnes for hydrogen and ammonia respectively, with investment costs of NOK 16.8 and NOK 15.9 billion in 2020. The analysis suggests cost reductions of around 50% towards 2030. The Net Present Value (NPV) suggest that the project would not be profitable with a system life expectancy of 20 years but could be profitable when a 30-year life expectancy is assumed. The largest cost driver is the floating wind farm, which constitutes 61% and 83% of the projected cost.

# Sammendrag

Denne avhandlingen er en mulighetsstudie som har til oppgave å undersøke mulighetene for å bruke en flytende vindmøllepark og hydrogen eller ammoniakk til å drive en offshore-plattform. Plattformen det gjelder er en hypotetisk plattform med et konstant effektbehov på 40 MW. Den flytende vindparken vil drive plattformen, og i perioder med overproduksjon vil overskuddsenergien produsere hydrogen eller ammoniakk, noe som igjen vil drive plattformen når det ikke blåser.

Studiet vil analysere hvor teknologigapene er og hva som er kostnadsdrivere for et slikt prosjekt.

Utregninger viste henholdsvis et behov for 170 og 220 MW vindkraft, og en lagringskapasitet på 1200 og 9500 tonn for hydrogen og ammoniakk, med investeringskostnader på 16.8 og 15,9 milliarder i 2020. Analysen viste en kostnadsreduksjon opp mot 50% mot 2030. Nåverdi antyder at prosjektet ikke vil være lønnsomt med en forventet levetid på 20 år, men kan bli lønnsomt dersom en 30 års levetid er medregnet. Den største kostnadsdriveren er vindparken som bidrar med 61% og 83% av kostnadene.

# Table of contents

# 1 Nomenclature

| | |
|---|---|
| Green hydrogen | =Hydrogen made without any $CO_2$ emissions |
| R&D | =Research and Development |
| CapEx | =Capital expenditure |
| OpEx | =Operating expense |
| $Sm^3$ | =Standard cubic meter |
| MW | =Mega watt |
| ICE | =Internal combustion engine |
| H-B process | =Haber-Bosch process |
| NPV | =Net Present Value |
| FC | =Fuel cell |
| Cracking | =Separating ammonia into nitrogen and hydrogen |
| $H^+$ | =Hydron |
| $NO_x$ | =Nitrogen Oxide |
| SWRO | =Saltwater Reverse Osmosis |
| ASU | =Air Separator Unit |
| $CO_2$-equivalents | =Carbon Dioxide Equivalent |
| $\eta$ | =Efficiency |

# 2 Introduction

Ever since the Norwegian production of oil and gas started in the 1970s, Norway has made a fortune and established itself as one of the wealthiest countries in the world per capita. Every year Norway exports large amounts of crude oil and gas worth hundreds of billions of NOK. The Norwegian oil and gas production are located offshore, and platforms powered by either diesel or gas are being used to extract these substances. The platforms emit large amounts of climate gases, due to the use of fossil fuels to generate power. The emissions are so large that oil and gas production is the second largest source of climate gas emissions in Norway and constitutes 27% of the country's total emissions.[18] With an increasing focus on limiting climate gas emissions worldwide in order to slow down climate change, new sources of energy are needed. Even major income sources such as the oil and gas industry will have to adapt. The use of wind power worldwide is increasing, and it presents a renewable way of producing energy. If the wind power is combined with environmentally friendly energy storage such as hydrogen or ammonia, it will potentially be possible to run a platform without the large climate gas emissions.

This thesis is a feasibility study intended to investigate the possibilities of using a system based on wind power combined with hydrogen or ammonia to power an offshore platform. The platform in question is a hypothetical platform with a constant power demand of 40 MW. The wind farm will power the platform, and in periods of overproduction the excess power will power electrolysers to produce hydrogen or ammonia. In periods where the wind power is not enough to power the platform, the stored hydrogen or ammonia will be used to produce power.

The purpose of a study like this is to envision how this kind of system would work, as well as determine if it is economically profitable. During this study, the needed capacity of the wind farm and the entire hydrogen or ammonia system will be calculated. In addition to this, a techno-economic study will be carried out in order to get a perception of what systems like these would cost. These main parts of the project will culminate into an answer to the following questions: What are the cost drivers and where are the gaps in technology when using wind power and hydrogen or ammonia to run an oil or gas platform?

# 3 Method

In this thesis, there have been conducted literature studies, various interviews, techno-economic-, wind- and sensitivity-analyses. A challenge this thesis encountered was that there were not many scientific publications on the subject of electrification of platforms using a floating wind farm and hydrogen or ammonia. It was therefore important to strengthen the quantitative findings by obtaining greater insight into the perspective of relevant companies. This insight was achieved through several in-depth interviews.

As mentioned, it was not many scientific publications on the field of total electrification of oil platforms with floating wind power. The literature study therefore had its main focus on two areas: technical reports researching isolated production of hydrogen or ammonia, or studies on a specific component of the systems, such as fuel cells and storage possibilities.

Two methods were implemented to increase the validity of the project: cross-checking sources and sensitivity analyses. Cross-checking of the sources happened in two ways. First, we started by comparing the different data sources such as websites, reports and books. Afterwards these data were compared to what the industry had explained in the interviews. This was a greater challenge than presumed, as there is a great deal of uncertainty in the various numbers. It was therefore made some estimates in collaboration with industry and academia.

For further validation of the thesis there were made several sensitivity analyses. This was done to get a better understanding of how the different parameters would change the outcome and showcase how big the differences are in the estimates.

The field of this project is in its infancy, and this suggests that the data will change frequently. It is therefore uncertain if a new study would conclude similarly.

# 4 Background

## 4.1 Wind Power

As mentioned at the beginning of this report, offshore platforms usually get their electricity from diesel generators or gas turbines. By replacing these sources of electricity with wind turbines it is possible to cut the climate gas emissions and run the platforms on green energy. In this section of the report, wind power will be explained as well as key aspects related to wind power will be discussed.

Wind power works by using turbines that convert the kinetic energy in wind into electric energy. The efficiency of this process varies depending on the type of turbine. All wind turbines have a theoretical maximum efficiency of 59% due to Betz limit, although the most common efficiencies are 35-45%.[19] A turbine´s rated power is its theoretical maximum power output. Combined with the capacity factor it can give an estimate of the expected power production from the wind turbine. The capacity factor is the result of taking the yearly power production from the wind turbine and dividing it on the rated power multiplied with hours per year.

It is important to know the cut-in wind speed, rated wind speed, and cut-out wind speed of a turbine. These numbers show at which wind speed the turbine starts producing power, where it produces its rated power, and at what wind speed it stops producing power respectively. The figures will vary from one turbine to another. When the turbine measures wind speeds surpassing the cut-out wind speed it turns its blades to reduce the surface area towards the wind and shuts down the production to reduce strain on the rotor.

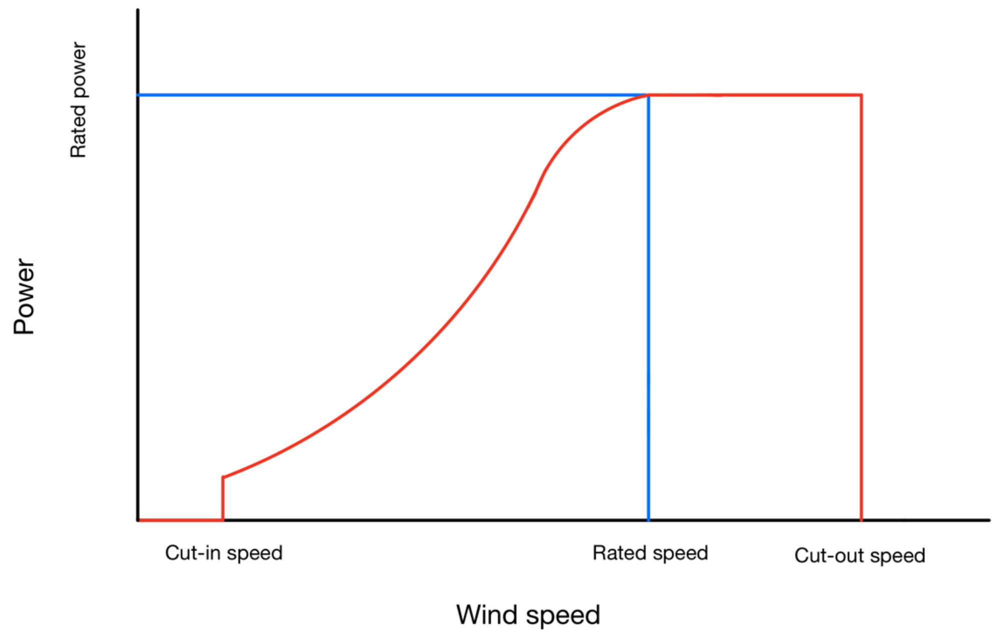


*Figure 1 Power Curve*

Cut-in wind speed, rated wind speed, and cut-out wind speed are as mentioned important features to understand, and they are key elements in the power curve. An example of a standard power curve is illustrated in figure 1 and shows the power output from a given turbine at any given wind speed. This is used to calculate power output at varying wind speeds to determine the total production. Some of the problems related to wind power, and often renewable energy generally, is also clearly illustrated. The fact that the production stops when the wind speed is either lower than the cut-in wind speed or higher than the cut-out wind speed, leads to a significant intermittency. This leads to the need for an energy storage solution, for example hydrogen or ammonia, to store energy when there is an overproduction of wind power and to supply energy when there is a shortage of wind power.

The market for wind power is growing and the global cumulative installed capacity has risen from 121 GW in 2008 to 591 GW in 2018 as shown in figure 2 [5]

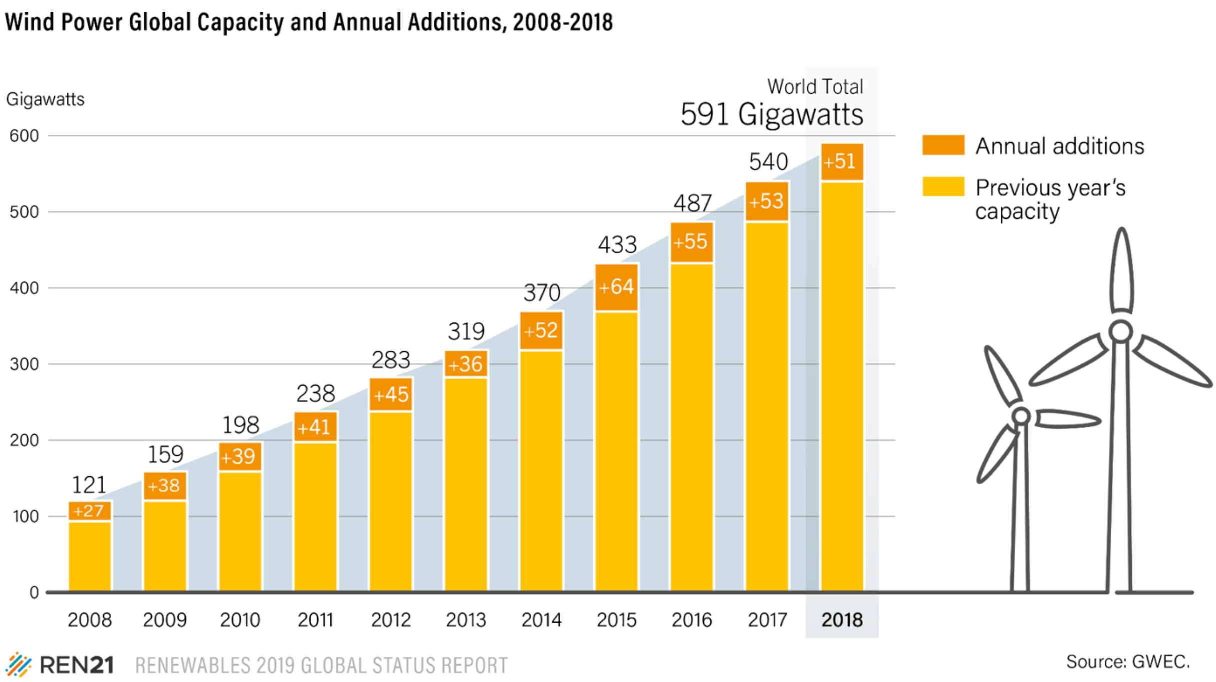


*Figure 2 Wind Power Global Capacity and Annual Additions [5]*

The continued increase in capacity is expected to lead to a decrease in cost in years to come. Depending on the wind resources and the financing of any particular project, land-based wind power is one of the cheapest energy sources available.[20] However, floating offshore wind turbines are still considered as a far less mature technology. The result of this is a higher price, and the current cost of floating offshore wind turbines is estimated to be above NOK 60 million/MW.[17] As mentioned, the cost is expected to decrease. With the expected scale increase as well as increased maturity and continued research and development (R&D), the prices are expected to decrease by over 50% and come down to around NOK

26 million/MW in 2030.[17] Although the decrease in price is significant, the cost of the wind farm is still expected to be the biggest part of the total CapEx for this project.

## 4.2 Hydrogen

### 4.2.1 Production of hydrogen

Since hydrogen is a substance that is not found in its natural state in nature, it is necessary to produce it chemically. There are several ways of producing hydrogen, with steam reforming as the current frontrunner. Since this thesis is focusing on green hydrogen, an electrolyser will be used, and therefore the hydrogen will be produced from separation of water.

There are several types of electrolysers available on the market, with alkaline electrolysers as the most common. This section of the report will give an overview of the two major types of electrolysers; alkaline and proton exchange membrane (PEM).

The efficiency of hydrogen production shows how much useful energy is left after the process. Because of this, it is important to consistently use either the lower, or higher heating value when calculating energy output. In this section, the lower heating value will be used because this does not take energy in the form of heat into the calculations.

#### *4.2.1.1 Alkaline*

The alkaline electrolyser is as mentioned the most common electrolyser, and the name alkaline comes from the use of an alkali electrolyte. This type of electrolyser often uses a water solution with 25-30% potassium hydroxide (KOH). The efficiency of the alkaline electrolyser is, based on the lower heating value, between 55-69%.[21] This is higher than both PEM and solid oxide electrolysers. Since alkaline electrolysers are most common, it is a well-developed technology that leads to it having a lower price than its competitors. According to E4Tech and Element Energy the price of an alkaline electrolyser-system will drop to 370-800 €/kW in 2030 from a price of 1,000-1,200 €/kW in 2014.[22]

#### *4.2.1.2 Proton exchange membrane*

Like all electrolysers, the PEM electrolyser gets its name from its electrolyte, which in this case is nafion. The efficiency of this kind of electrolyser is between 55-66%, which makes it slightly lower than alkaline electrolysers.[21] PEM is also a quite mature technology and has been used since 1966. Despite this, it is expected that its potential for efficiency increase and cost reduction is higher than alkaline electrolysers. E4Tech and Element Energy estimates that the price of PEM electrolysers will drop to 250-1,270 €/kW in 2030 from 1,900-2,300 €/kW in 2014.[22]

### 4.2.2 Hydrogen for power

There are several ways to produce electricity from hydrogen, all with varying efficiency. Fuel cells are currently the most promising technology and represent an emission free solution. In this section of the report, 3 different variants of fuel cells will be looked at, as well as hydrogen combustion engines, which provide a different solution.

#### *4.2.2.1 Solid oxide fuel cell (SOFC)*

SOFC is a high-temperature fuel cell operating within 700-1,000ºC, and it uses solid ceramic oxide as an electrolyte. SOFC is unique because it can reach an efficiency of up to 70 %, which is the highest in today's market. According to Shell "SOFCs have developed into the second most important fuel cell type after the PEMFC". Furthermore, the technology is mature, and volume is rising. One problem with SOFC is its high temperature which can easily complicate the process. [23]

#### *4.2.2.2 Alkaline fuel cell (AFC)*

The alkaline fuel cell was one of the first commercialized fuel cells. It was used as far back as 1960 when it was on-board power for an Apollo mission. In today's society, it is still used primarily for space travel and submarines. The AFC is in the category of low-temperature fuel cells and operates in 60-90 ºC with an efficiency of 60-70%. Unfortunately, AFC has a particularly low tolerance for carbon dioxide and therefore requires a substantially pure gas. The fuel cell has been in the market for decades, but it is limited to a few applications. [21]

#### *4.2.2.3 PEM fuel cell (PEMFC)*

PEM fuel cells obtain energy from a red-ox reaction where the hydrogen at the anode is oxidized to $H^+$ and $e^-$. The hydrogen flows through electrolytes and the electrons move onwards to the equipment. The reaction rate can be enhanced by applying a higher temperature. It is common to use a catalyst, usually platinum. PEMFC is well suited for small scale applications because it is quite dense. The efficiency of PEMFC is theoretically near 100%, but when tested in real-life applications the realistic efficiency is around 50-60%.[21] In the future, efficiency is expected to increase. Statkraft explained in an interview that in regard to the development of new technology, the efficiency can be expected up to 85%. This is obtained with the utilization of the heat generated in the process, which corresponds to the higher heating value.[24]

#### 4.2.2.4 Subsea fuel cells

CMR Prototech is now developing a Clean Highly Efficient Offshore Power (CHEOP) solution to power offshore platforms. Its intent is to reduce CO2 emissions with 50% of the original values. The CHEOP concept is made up of a 32 MW fuel cell, with a combination of SOFC- and PEM-stacks.[25] While developing this technology they also proved that the fuel cells can be placed subsea.[10] The technology is currently under development and is not ready to be utilized. Figure 3 illustrates Prototech´s vision on subsea fuel cells.

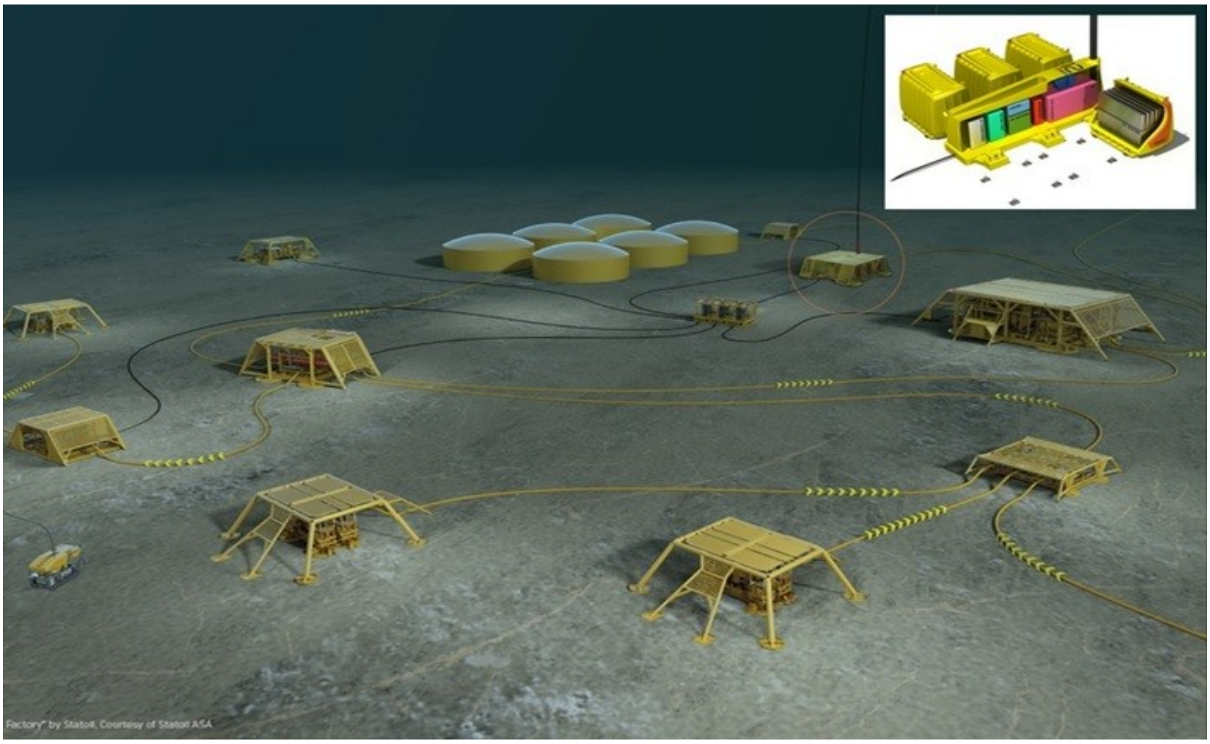

*Figure 3 Prototech Subsea fuel cell system [10]*

#### 4.2.2.5 Combustion engine

As discussed, hydrogen can be used in a fuel cell to produce electricity. Hydrogen can also be used in a combustion engine, similar to gasoline and diesel. When hydrogen is used in a combustion engine, water and heat is produced in this reaction:

$$2H_2 + O_2 = 2H_2O + heat$$

However, there is also a side reaction which occurs due to the high temperature, where nitrogen and oxygen in the air reacts to form Nitrogen Oxide ($NO_x$) in this reaction:

$$H_2 + O_2 + N_2 = H_2O + N_2 + NO_x$$

Even though there are no carbon emissions from this reaction, there are as shown $NO_x$ emissions. $NO_x$ has a global warming potential (GWP) of 30-33 $CO_2$-equivalents, which is comparable to methane.[26] The global warming potential is a way to compare different climate gasses abilities to heat the atmosphere.

It is difficult to name a price for this kind of system because it is not commercialized. However, it is reasonable to assume that it would be cheaper than a fuel cell system because it is possible to use a modified conventional engine.

The main problem however with this system is the efficiency. The efficiency is comparable to that of normal combustion engines running either gasoline or diesel. This means an efficiency of around 20-25%.[27] Meanwhile a hydrogen fuel cell can have efficiencies of up to 60-70%. This lower efficiency means that it takes significantly more hydrogen to produce the same amount of electricity. That means more power to produce more hydrogen and a great increase in the need for storage.

### 4.2.3 Storage

In this report both ammonia and hydrogen are looked at as possible ways to store surplus energy from wind power. This part of the report will focus on storage solutions for hydrogen.

As shown in figure 4, hydrogen has a significantly higher gravimetrical energy density than other fuels such as gasoline and diesel, and an even greater gravimetrical energy density compared to batteries. This is favourable for applications where weight is a decisive factor. On the other hand, hydrogen has a low volumetric energy density, which makes it challenging to store in small areas.

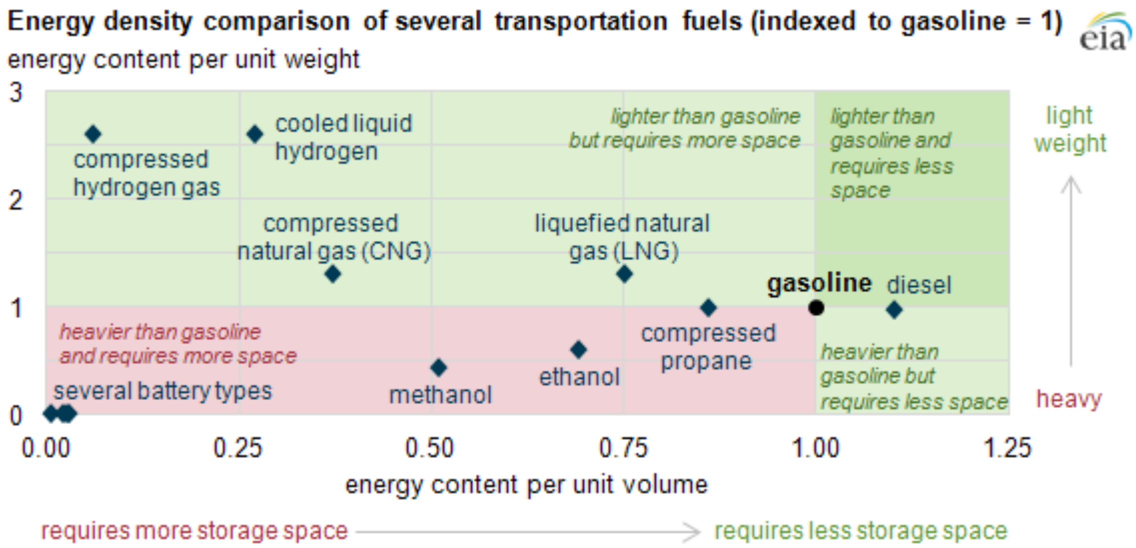


*Figure 4 Energy Density Comparison of Several Transportation fuels*

As shown in figure 5, there are several ways to store hydrogen, and factors such as price, weight, and volume will determine which storage method to use. In this part of the report the three ways of storage, which will be investigated are hydrogen as a compressed gas, as a liquid, and as a metal hydride.

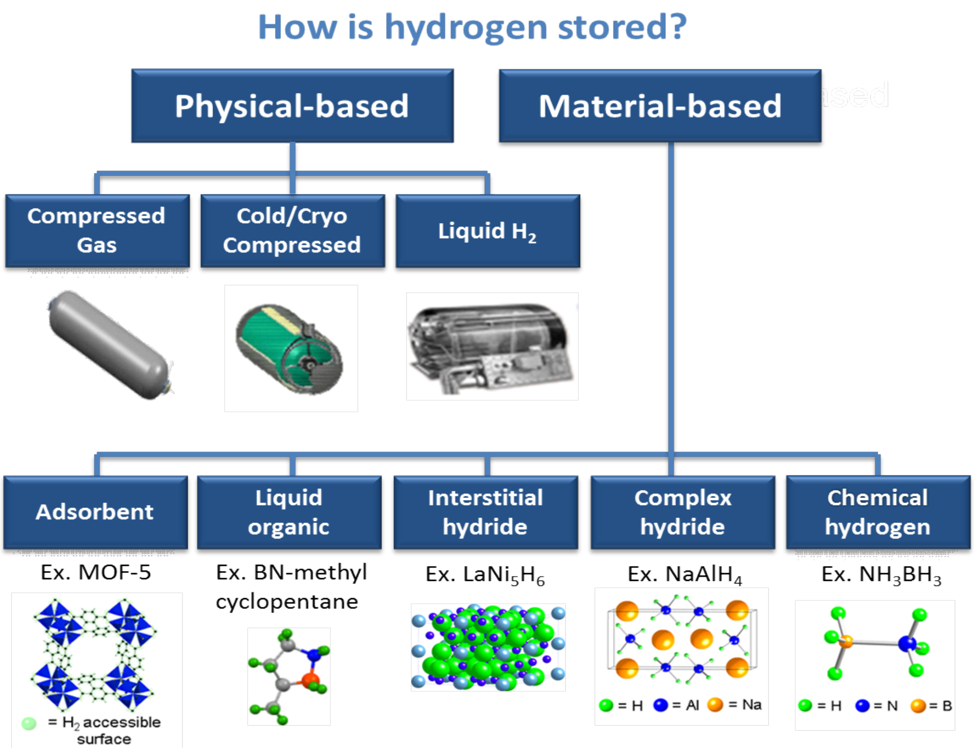


*Figure 5 Different Types of Hydrogen Storage[3]*

### *4.2.3.1 Compressed hydrogen*

The most mature technology for storing hydrogen is in high-pressure tanks, and this technology is often viewed as the most viable near-term option. Today, high-pressure hydrogen tanks are being used for several applications, for instance on-board automotive physical storage. Usually for the automotive industry the hydrogen is stored at either 350 Bar or 700 Bar, depending on what type of vehicle is being used. With larger vehicles, 350 Bar are often chosen because there is more space available. Also, compressing hydrogen at 700 Bar requires more energy. It is furthermore more expensive as the storage tanks have to be more robust, and therefore require the use of more expensive materials. Numbers from the U.S Department of Energy show that the price of storing hydrogen at 700 Bar was $15/kWh in 2016 with a future target price of $8/kWh.[4]

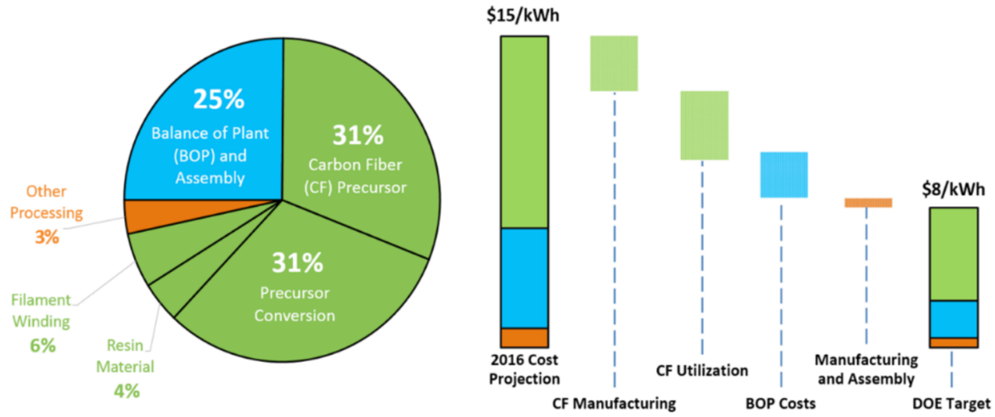


*Figure 6 overview of DOE target price for hydrogen storage[4]*

The storage tanks, especially those at 700 bars, are as mentioned made from costly materials such as carbon fibre. The use of this material helps keeping the weight down and ensures that the tanks have high structural strength. To reach DOE´s target of $8/kWh, the price of carbon fibre will have to decrease, or new materials must be developed.

Compressed hydrogen has a volumetric density of 23 kg/m$^3$ at 350 Bar and 38 kg/m$^3$ at 700 bars.[28] This low volumetric density makes this storage solution less suitable for several applications and takes up significantly more space than a traditional fuel systems does.

#### *4.2.3.2 Liquefied hydrogen*

Another solution for storing hydrogen is cooling it down to form a liquid. To achieve this liquid form, the hydrogen must be cooled down to a temperature of -253°C or 20 Kelvin. This process is energy demanding and can require 20-40% of the total energy contained in the hydrogen.[29] Another issue with storing hydrogen as a liquid is boil-off, which can add a loss to the stored energy.

The reason as to why hydrogen is stored as a liquid, is the fact that liquid hydrogen has a significantly larger volumetric density compared to compressed hydrogen. While compressed hydrogen, as mentioned, has a volumetric density of 23 kg/m$^3$ at 350 Bar and 38 kg/m$^3$ at 700 Bar respectively, liquid hydrogen has a volumetric density of 70 kg/m$^3$. Fewer tanks are required when increasing the volumetric density and this makes it possible to both store and transport more hydrogen.

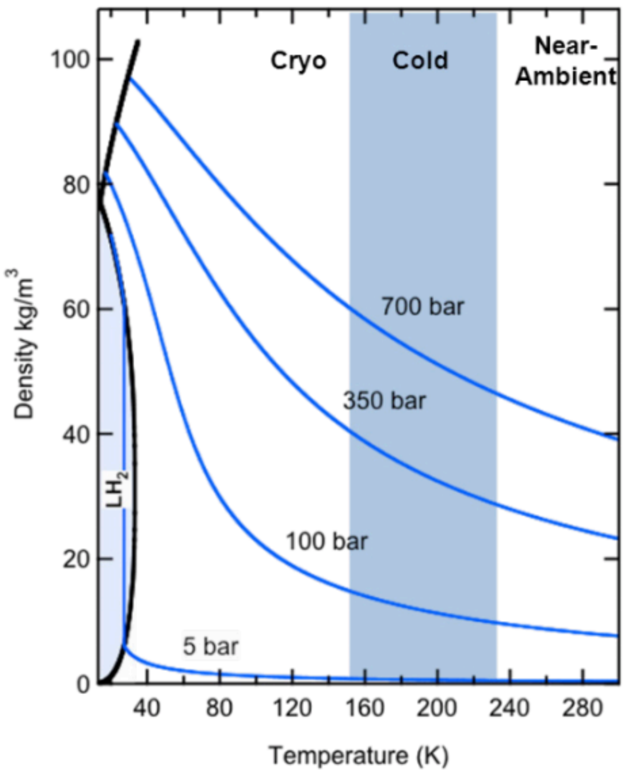


*Figure 7 Density of Different Storage Solutions [4]*

As shown in figure 7 liquid hydrogen requires significantly less pressure than compressed hydrogen when stored. This lack of pressure eliminates concerns regarding high pressure storage but is not without its drawbacks. With liquid hydrogen, there are concerns regarding its behavior in the case of a leak. While compressed hydrogen will quickly rise in the event of a leak, liquid hydrogen can freeze the surrounding air due to its low temperature, and thus form a cloud of hydrogen. The hydrogen will eventually rise when it is heated, but this could become a problem if large quantities of hydrogen collect around the leakage zone.

To store liquid hydrogen, specially designed tanks are needed. The tanks often used are vacuum-isolated tanks, and they are often expensive.

#### *4.2.3.3 Metal hydrides*

Most metals have the ability to react with hydrogen to form metal hydrides. The temperature and pressure in which the metals will absorb the hydrogen will vary from metal to metal. Some metals will absorb hydrogen at room temperature and atmospheric pressure, while others require high temperatures and high pressure. Similarly, the opposite reaction, desorption, requires different temperatures and pressure depending on the choice of metal. The chemical reaction between the metal and the hydrogen can be expressed with the following equation, where x is the number of hydrogen molecules which reacts with the metal:[15]

$$M + \frac{x}{2}H_2 <-> MH_x + Heat$$

One benefit of using metal hydrides are their compactness. While, as mentioned, you can store about 23 kg/m$^3$ and 70 kg/m$^3$ of hydrogen at respectively a pressure of 350 Bar, and as a liquid, the capacity from metal hydrides are higher.[28] Depending on the choice of metals, it is possible to store more than 100 kg/m$^3$ of hydrogen due to the way the hydrogen atoms adsorb to the metal atoms as shown in figure 8.[15] This increase in volumetric density is favourable for applications where space is an issue.

Furthermore, the hydrogen is stored at low pressure when utilizing a metal hydride system, which eliminates safety concerns regarding high pressure storage. The fact that the hydrogen is attached to the metal ensures that there is no hydrogen gas escaping in the event of a leak. Another advantage of the metal hydrides is the fact that it does not require electricity to work, and the absorption and desorption can be controlled by adjusting the temperature.

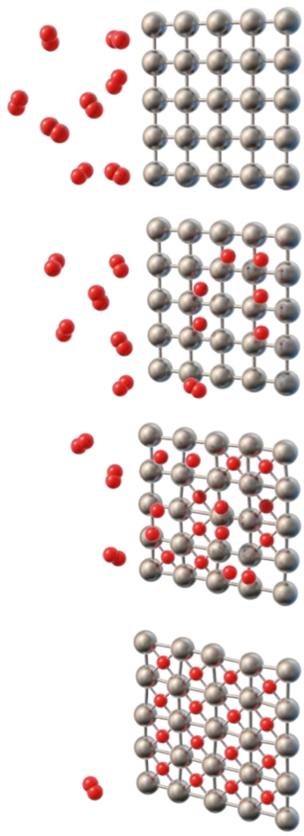

*Figure 8 Metal Hydrid* [15]

Although metal hydrides are a promising technology, they are not without their drawbacks. Since the technology is still at an early stage commercially, the prices are generally high and not competitive with more commercial storage solutions. Another drawback of this technology is its high weight due to the metal required. This weight leads to a low weight percentage of hydrogen, and therefore excludes this technology from being used in several applications. The metal hydrides are best suited for stationary applications, and applications where weight is desirable.

#### *4.2.3.4 Subsea storage*

There is currently no commercialized solution for subsea hydrogen storage, but Umoe is working to change this. Umoe is in the consortium which is developing Deep Purple, where they are responsible for the storage.[1][6] Umoe is looking to store the hydrogen in cylindrical tanks at a pressure of 350 bar. Each tank would hold 1925 liters, or around 40 kg, with a cost of NOK 150000 /tank and Umoe assumes a lifetime of 30 years. [30]

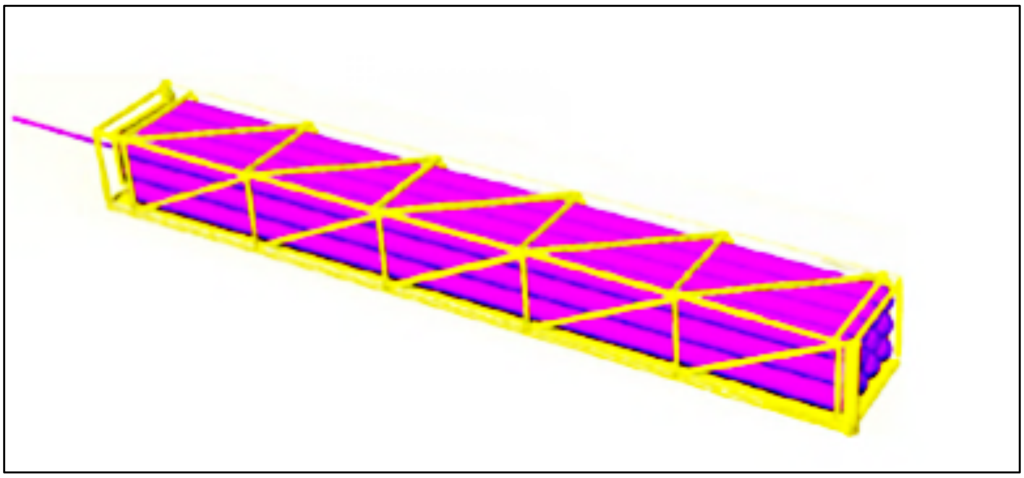

*Figure 9 Umoe subsea storage [6]*

## 4.3 Ammonia

During this shift in the energy market, numerous people look to ammonia as a significant carbon-free energy carrier. Norwegian energy major Equinor has started a project where they look at ammonia to power their ship "Viking Energy" in 2024.[31] Ammonia, the colourless, pungent gas, is an source of high contents of hydrogen in its liquid form. The volumetric hydrogen density is 1.5 times of liquid hydrogen at 10 Bar and -253°C.[32] Contradictory to liquid hydrogen, liquid ammonia does not need to be stored in cryogenic tanks, but can be stored at room temperature if the adequate pressure is upheld. Another benefit of ammonia is that it, like hydrogen, can be manufactured with a complete carbon-free process from renewable power sources. Furthermore, ammonia has a proven infrastructure that transports over 180 million tons per year.[33] Some disadvantages with ammonia is its corrosive nature to copper, brass and zinc alloys, poor flammability limit and its low volumetric density as a gas. [33]

### 4.3.1 Production of ammonia

Production of ammonia is a well known process. Most of the ammonia is synthesized using the Haber-bosch process (H-B process), with hydrogen from natural gas. This process is affordable, but its downside is that it emits a vast amount of $CO_2$, and it is energy consuming. If the hydrogen is made from green electricity, however, the problem with $CO_2$ would disappear.

#### *4.3.1.1 Haber-Bosch Process*

The H-B process begins with hydrogen gas, and nitrogen separated from the air, reacting under high pressure and temperature. The gasses are transported to a compressor where they are subjected to 200 bars. Onwards the pressurized gases are sent to the converter which heats the gases to around 450 °C. The converter uses an iron catalyst to aid the reaction. Throughout this process approximately 15% of the hydrogen and nitrogen become ammonia. The next step is a cooling tank where hydrogen, nitrogen and ammonia are cooled, which causes the ammonia to turn into a liquid. Here the liquid ammonia is collected and stored. Finally, the remaining nitrogen and hydrogen flows back into the converter where more ammonia is produced, then cooled and collected. This process is repeated until most of the hydrogen and nitrogen is converted to ammonia.[34]

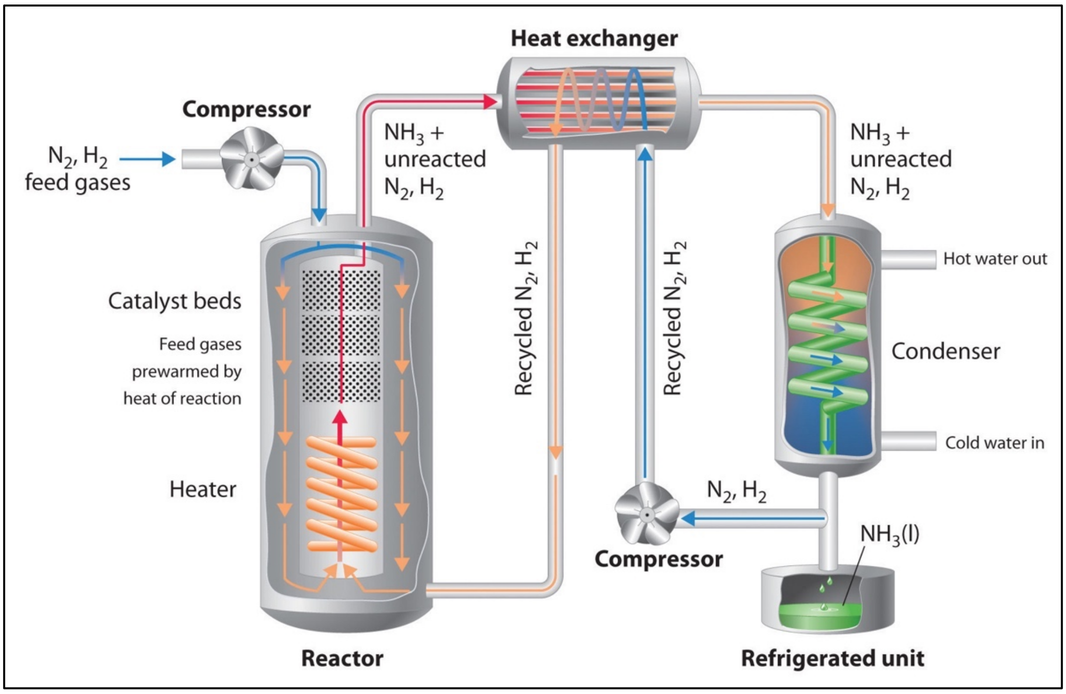


*Figure 10 A Schematic Diagram of an Industrial Plant for the Production of Ammonia via the Haber-Bosch Process[11]*

#### 4.3.1.2 Solid-state ammonia synthesis

Although most of the ammonia today is produced through the H-B process, there has been a technological development in the past two decades, and several alternatives to the H-B process have been proposed. One of these is the Solid-State Ammonia Synthesis (SSAS). This type of production uses a solid-state electrochemical process to produce ammonia from water, electricity and nitrogen. SSAS has higher efficiencies and requires less energy than HB. SSAS consumes 7,000-8,000 kWh/t-$NH_3$. The H-B process in combination with an electrolyser uses 12,000 kWh/t-$NH_3$ [35]

To begin the reaction, a proton-conducting membrane is heated to about 550 ºC. Nitrogen and water vapour are provided to each side of the membrane under pressure. The water vapour separates into hydrogen and oxygen. Applied by external voltage the oxidised hydrogen ($H^+$) are transported through the membrane as shown in figure 11. On the other side of the membrane, $NH_3$ is being produced as an outcome of nitrogen and $H^+$ reacting. Because the SSAS process requires less energy than HB, it will enable the production of ammonia at a lower $/kWh. Also, the SSAS does not require $H_2$ to be produced, and therefore can be produced without natural gas separation or electrolysis. This makes it very suitable for renewable energy sources, which can result in a financial and environmental advantage.[36]

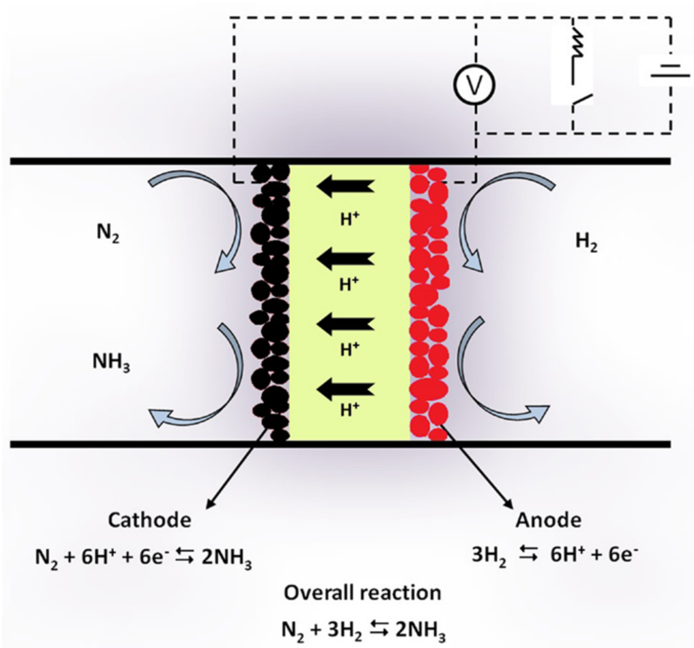


*Figure 11 Schematic Diagram of a Solid State H+ Conducting Cell Used for NH3.[16]*

SSAS is still not commercialized. In order to scale up and compete with the H-B process, SSAS must overcome some challenges. First, it needs to improve the proton conductivity of the cells and secondly the catalytic activity of the cathodic electrode.[16] If SSAS overcomes these challenges, it could be a prominent production method in the future.

### 4.3.2 Power from ammonia

#### *4.3.2.1 Combustion engine*

Internal combustion engines (ICE) have been tested with ammonia as a fuel, where both combustion ignition (CI) and spark ignition (SI) have been examined. This has discovered that ammonia as a fuel in an ICE is possible, but it has some disadvantages. One dilemma is that it has a conservative flammability limit and moderate flame speed which results in incomplete combustion.[37] In a CI-engine the high condensation rate causes a decline in gas temperature at the time of injection, which complicates the process even further.[38] Recently ICE fuelled by ammonia has considerable recognition commercially from different companies, most notably Wärtsilä, as they look to have an engine ready in the coming years.[14]

Studies indicate, based on system effectiveness, thermodynamic performance, and fuel tank compactness, that ammonia needs to be combined with additional fuels to be a sustainable fuel in an ICE.[33] This is expected since ammonia holds a low flame speed and high resistance to auto-ignition, which was proved in recent studies. These studies also illustrated that blending ammonia with other carbon fuels, like gasoline, is the most reliable means to improve combustion.[39, 40]

The study "Ammonia for power" concluded that for commercialisation of an ammonia internal combustion engine, additional analysis is profoundly important. The research pointed out that the most significant challenge is the emissions. The problem with reducing $NO_x$ and unburned ammonia remains at the heart of this research and technological field. Although direct injection of gaseous ammonia with multiple fuels has emissions challenges, it was proven to be attainable in a combustion engine. [33]

Although there are not any ICE currently running on ammonia, this could change soon. In a press release, Wärtsilä said that their company's goal was to "develop a complete ammonia fuel solution comprising engines, fuel supply, and storage".[41] Wärtsilä is studying both dual-fuel and spark-ignited gas engines. Wärtsilä is not new to the ammonia market since they are already developing an ammonia storage and supply system as part of the Eidesvik Offshore's supply vessel Viking Energy.[14] Wärtsilä is also saying that "The modularity of modern engines means that conversions can be made with a very limited exchange of component".[14] If successful, this would mean that there could come a major shift in the shipping industry, where several ships would switch from diesel to ammonia.

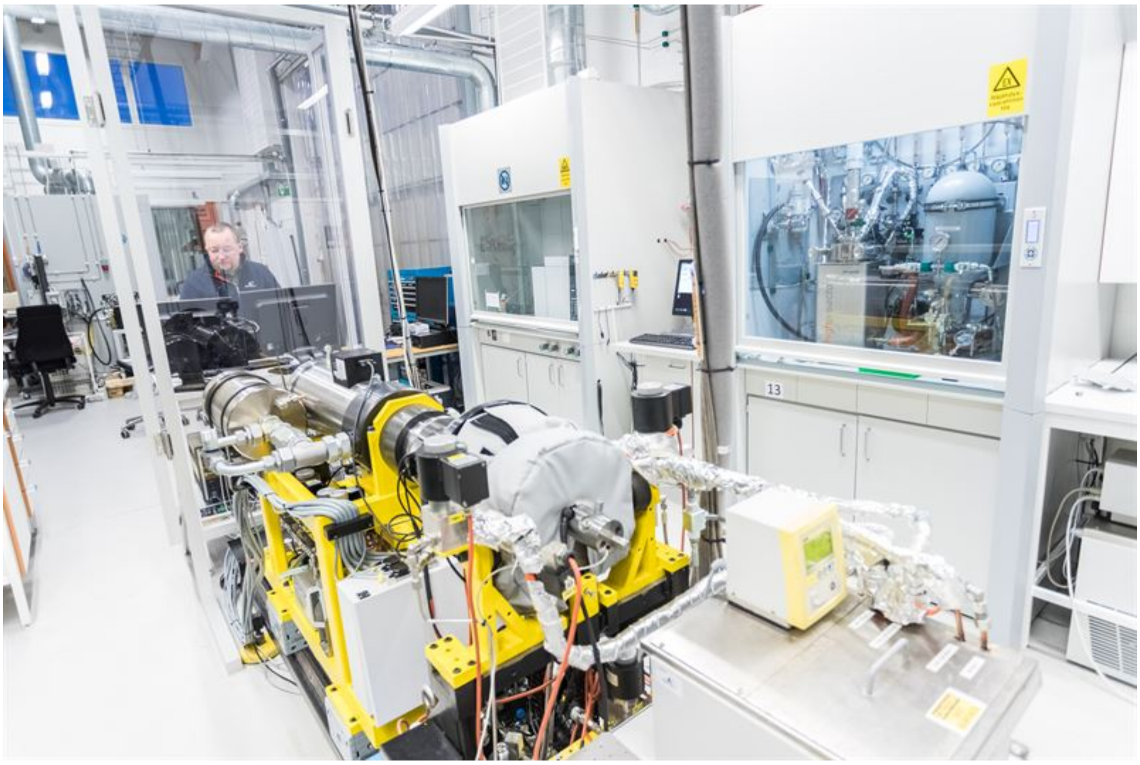

*Figure 12 Wärtsilä advances future fuel capabilities with first ammonia tests[14]*

#### 4.3.2.2 Fuel cells

There are two ways to use a fuel cell to generate electricity from ammonia; an ammonia fuel cell, or crack ammonia into nitrogen and hydrogen and use a normal hydrogen fuel cell.

It's quite simple to generate electricity from ammonia with a hydrogen fuel cell, assuming that the ammonia is stored as a liquid. At room temperature, ammonia gas can form naturally inside the storage tank with a change in pressure. The gas moves into the cracker where hydrogen and nitrogen come in contact with the catalyst and is separated. Onwards the atoms flow inside the fuel cell where the nitrogen atoms rush upwards and are released harmlessly into the air. Then the hydrogen atoms react with the membrane and creates electricity and water. One challenge with this process is the efficiency. The cracking is an energy consuming process with an efficiency of 76%.[42]

Currently there are not any commercialized ammonia fuel cells, but CMR Prototech has launched a project to change this. As mentioned, Equinor is looking to have the supply ship Viking Energy run on ammonia in 2024. Prototech is working to develop a 2 MW solid oxide fuel cell (SOFC) that can run on ammonia directly. This would enable the ship to sail entirely on the clean fuel for up to 3,000 hours annually. [43] A vital element of CMR Prototech´s project will be to scale up the current 100 KW fuel cell to 2 MW. Bernt Skeie, CEO of CMR Prototech, said in an interview that they feel confident of reaching the deadline and deliver the 2 MW fuel cell in 2024.[44] The testing of the fuel cell will be completed at the Sustainable Energy Norwegian Catapult Centre at Stord.[43] Studies have suggested that a solid oxide ammonia fuel cell would have an efficiency comparable to a hydrogen fuel cell at 50%.[43, 45]

### 4.3.3 Storage

Ammonia storage is a familiar process that has been utilized for a century. The industry has for a long time applied two fundamentally different types of storage: pressurized and low temperature. As the technology is developing and new business cases emerge, the new storage method subsea storage is on the rise.

#### *4.3.3.1 Pressurized storage*

Pressurized ammonia is contained in the tank at room temperatures with high pressure. Ordinarily, the gas is kept in a container that is spherical or cylindrical. The container is attached with multiple valves and controls to the surrounding components. Pressurized storage has a particularly big advantage since it has no demand for external energy. Furthermore, the system does not evaporate any fuel and can therefore be stored over a lengthy duration. One shortcoming of pressurized storage, however, is its low gravimetrical density.

As described earlier, pressurized ammonia would have some advantages over liquid ammonia. It does not need external energy to ensure that the gas do not evaporate, which means it would be suitable for off-grid locations. One shortcoming is nonetheless that the vessel would not contain as much ammonia per $m^3$ as it would in a liquid state. This suggests that for storage regarding the same quantity of energy, it would require considerably more volume with pressurized ammonia.

#### *4.3.3.2 Low temperature storage*

Ammonia can be stored as a liquid in two ways. One option is near atmospheric pressure, but this assumes that a sufficient temperature of -33 °C is maintained using a cryogenic container that includes a cooling system.[46] Without this system, the ammonia would automatically evaporate. In addition, the ammonia can be stored as a liquid if sufficient pressure of approximately 7,5 Bar in room temperature is upheld.[47]

A prominent advantage regarding low-temperature systems is that the container is only designed to resist the static pressure of the liquid. This indicates that the vessel would need less steel content compared to pressure storage.

#### *4.3.3.3 Subsea storage*

Paramount to understanding how ammonia can be stored subsea, is knowing how ammonia behaves with different pressure and temperatures. As mentioned, there are two ways to convert ammonia into a liquid. It can be cooled to -33 ºC at ambient pressure, or it can be subjected to 7-10 Bar at below 10 ºC. For every 10 meters underwater, there is approximately 1 bar pressure, it can therefore be assumed that from a depth of 70 meters ammonia will stay as a liquid.

There are not many companies that are developing this technology, but the company NOV is one exception. NOV is currently developing subsea storage for oil, but has explained that the technology can be used for ammonia and they are testing the solutions in the fall of 2020. The solution is to store the ammonia in bags instead of in solid tanks as hydrogen is stored. This solution is also how ZEEDS look to store their ammonia.[48] Figure 13 shows how the ammonia would be stored in bags, inside a container. Early assumptions suggest that the solutions could store 10,000 $m^3$ of ammonia, which holds approximately 36,000 MWh to a cost of NOK 300 million, which is around 1/10 of the cost for subsea hydrogen storage.[9] These numbers are estimates and are not guaranteed to be accurate. 10,000 $m^3$ of hydrogen would store 14,000 MWh at 700 Bar, and only 7,600 MWh at 350 Bar.

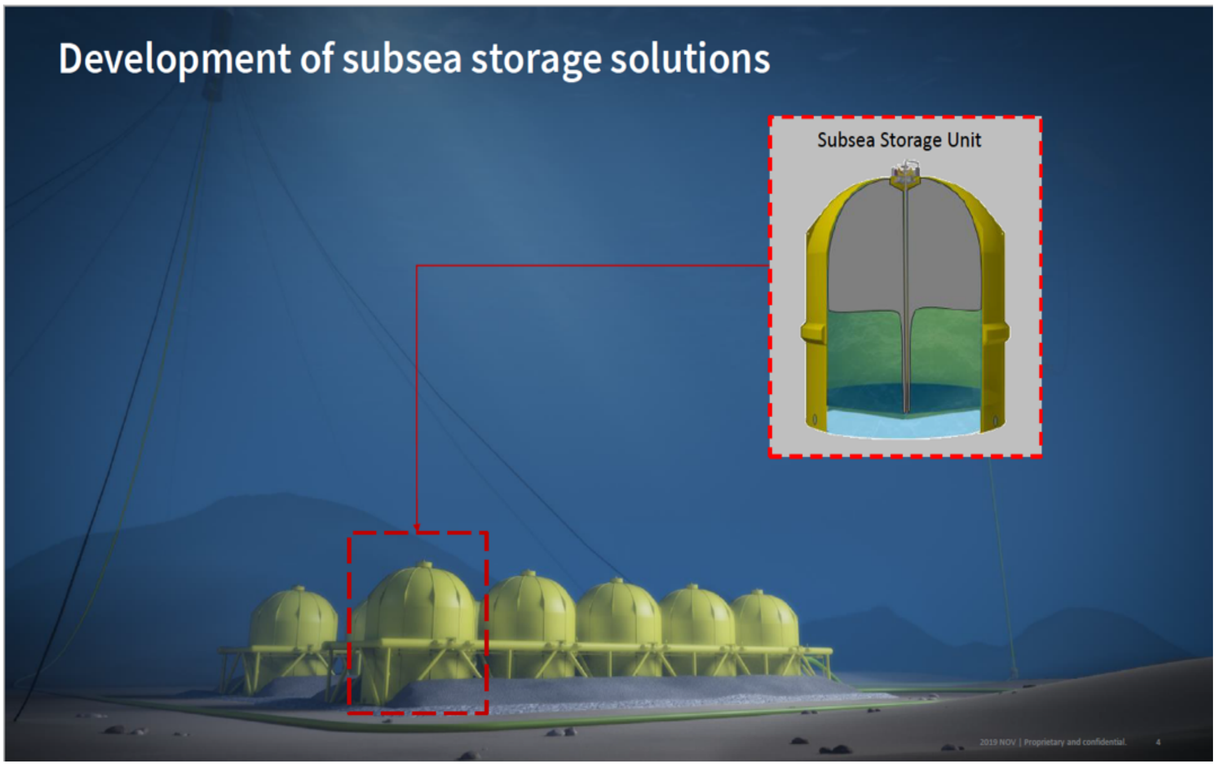


*Figure 13 Development of Subsea Storage Solutions by NOV [9]*

## 4.4 Related research projects

There are currently no commercialised solutions for the total electrification of a platform with floating wind and hydrogen or ammonia as a backup system. Although there have been some case studies for similar challenges. This section will attempt to establish an overview over the current solutions.

### 4.4.1 Deep purple

Deep purple is a joint venture including various companies where Technip FMC is the project leader. The project aims to produce hydrogen from floating windfarms with subsea hydrogen storage, either for electrification of a platform or to produce hydrogen as a fuel for ships as figure 14 shows. [6]

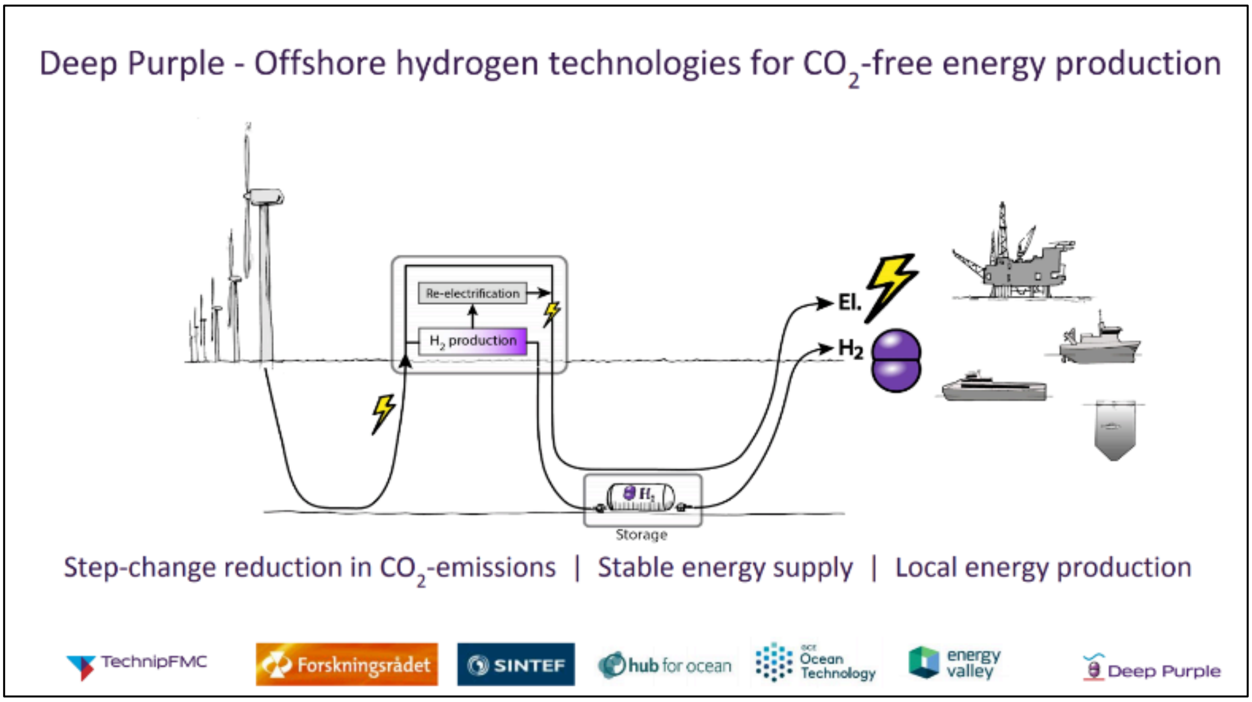


*Figure 14 Deep Purple [6]*

The project has an interesting vision for offshore hydrogen production. Some projects aim to have a separate platform with production and storage of hydrogen, Deep Purple is studying the possibility to have the electrolysers, fuel cells and saltwater desalination inside the windmill. This means that an external platform would not be necessary, which in turn may lead to cost reduction.

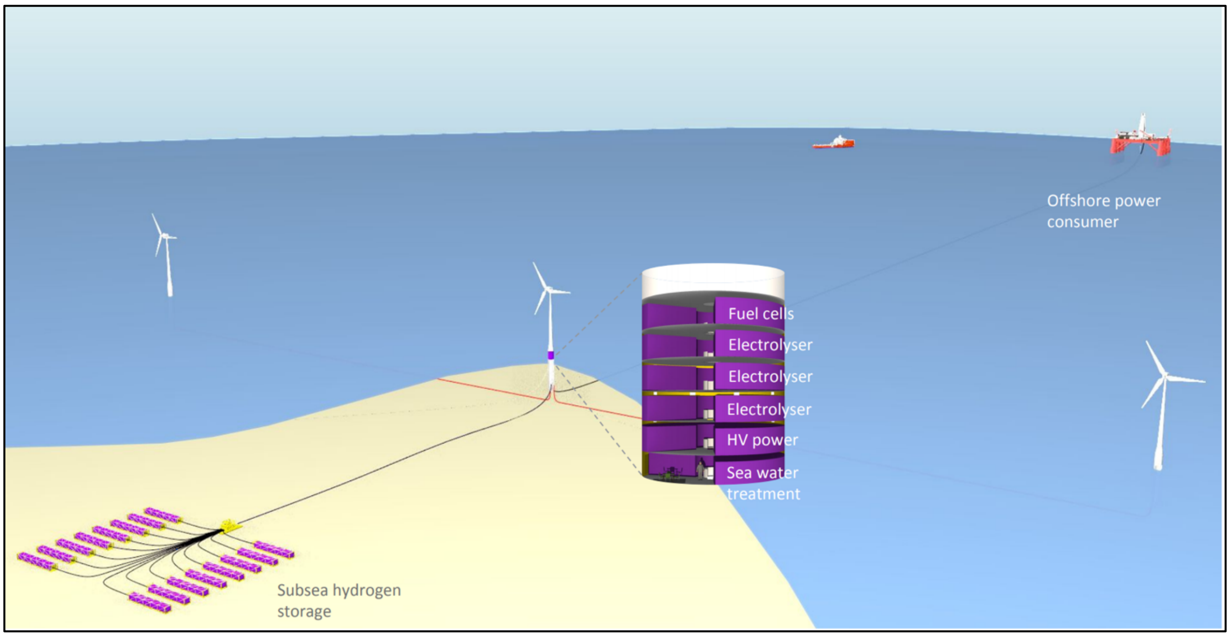


*Figure 15 Deep Purple [6]*

### 4.4.2 ZEEDS

ZEEDS is a joint venture with Aker Solutions, Equinor, Kværner, Grieg Star, DFDS and Wärtsilä.[48] ZEEDS is working to make zero-emissions shipping possible by making energy hubs in the North Sea. ZEEDS has some similarities to Deep purple, as they both explore the possibility of subsea storage and floating wind turbines. However, contradictory to Deep purple, ZEEDS produces ammonia and not hydrogen. This is largely due to the fact that ZEEDS aims to produce zero-emission fuel for vessels, and they assume that ammonia would be the favourable fuel.

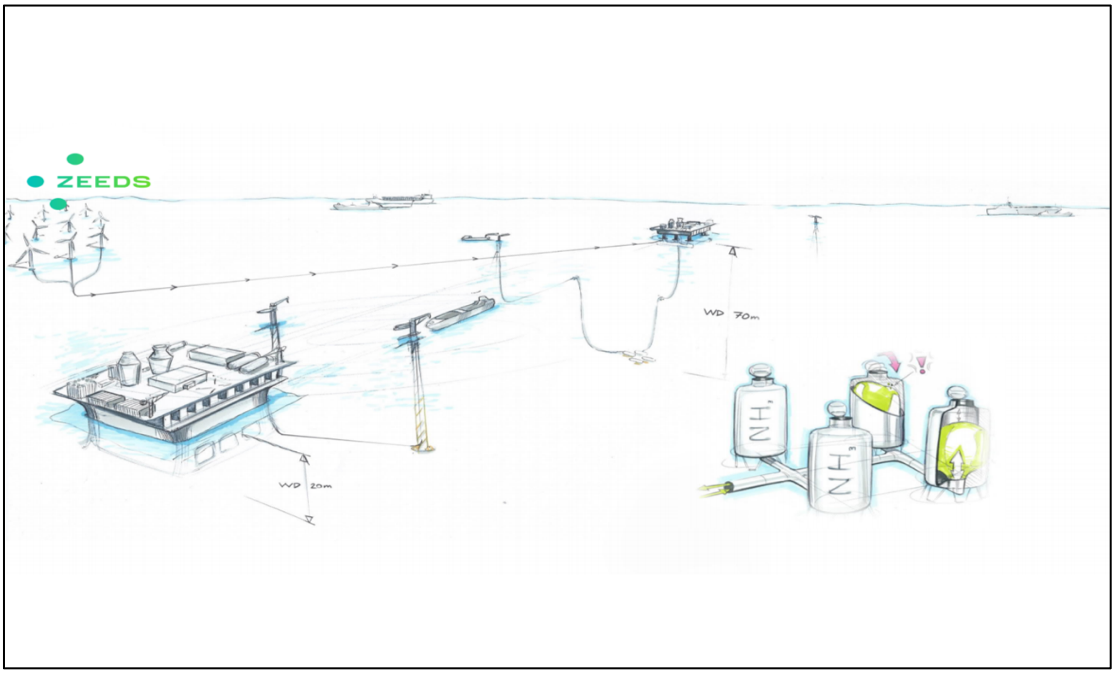


*Figure 16 ZEEDS [1]*

### 4.4.3 DNV GL

In 2015 the students in DNV GL summer project made a solution for hydrogen from floating wind. Their task was to offer a solution for offshore production, storage and transportation of green hydrogen. The result was "Jidai", which contrary to the other projects listed, looks to have storage topside on the production platform.[8]

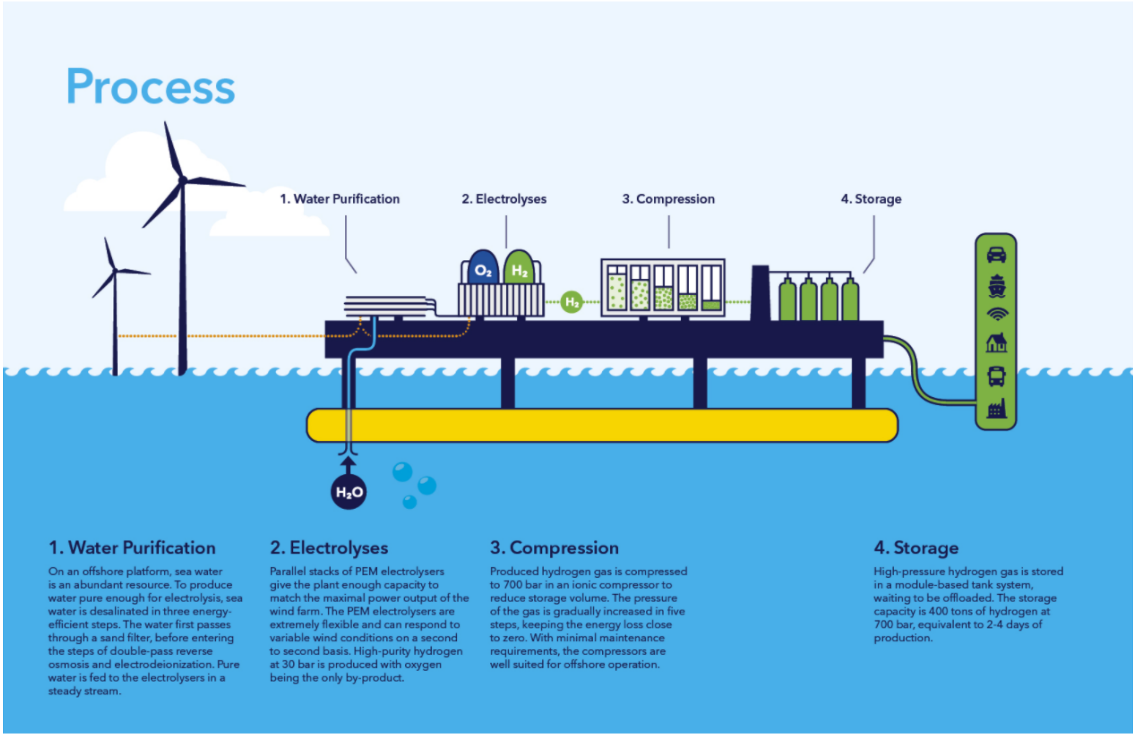


Figure 17 *DNV GL .[8]*

# 5 Results of wind- and energy storage calculations

## 5.1 Determining energy backup system

When designing a system like the one in this project, one can choose several different solutions. As listed in the background chapter there are different ways to produce, store, and utilize both hydrogen and ammonia. There are some factors to take into consideration when choosing the individual components to use, with price and space as some of them. Due to limited time and resources for this project, 4 different cases were assessed before 2 was chosen to be examined more in-depth. The different cases are presented in the next subsection of this report.

### 5.1.1 Case 1: hydrogen stored at 700 Bar

Case 1 uses hydrogen as energy storage. The production of hydrogen comes from an alkaline electrolyser, and the hydrogen is then compressed to 700 Bar before it is stored in high pressure tanks subsea. The power production from hydrogen comes from a PEM fuel cell, which delivers power to the platform.

### 5.1.2 Case 2: hydrogen stored at 350 Bar

Case 2 uses the same system as case 1 with an alkaline electrolyser and a PEM fuel cell. The difference between the two cases, is the fact that in case 2 the hydrogen is compressed to, and stored at, 350 Bar instead of 700 Bar.

### 5.1.3 Case 3: ammonia in internal combustion engine

Case 3 uses ammonia as energy storage. Firstly, hydrogen is produced as in the examples above before it goes through the H-B process to produce ammonia. The ammonia is then stored subsea, and it is assumed that the subsea storage would be 70 m below sea level or more. It is therefore presumed that the ammonia would be a liquid. To produce electricity from the stored ammonia, an internal combustion engine is being used, and it is assumed that it runs on 100% ammonia. The ICE powers a generator that produces electricity, which is being sent to the platform.

### 5.1.4 Case 4: ammonia in a fuel cell

Case 4 uses ammonia similar to case 3. The ammonia is produced in the same way through an H-B process and is then stored as a liquid subsea. The difference between the 2 cases is that instead of using an ICE as in case 3, a fuel cell is being used. The fuel cell uses ammonia and directly produces electricity without an external generator. As mentioned in chapter 4.3.3.2, there are no ammonia fuel cells on the market, but this thesis assumes the use of CMR Prototech´s proposed solution

### 5.1.5 Comparison

When deciding which of the 4 cases to use, several calculations were made. There are several steps to all 4 cases, and each step has its own efficiency. These steps include saltwater desalination, electrolysis, compression, storage, fuel cell or ICE with a generator for electricity production as well as the H-B process for the ammonia. All these efficiencies combine to form a total efficiency for the entire hydrogen or ammonia system. The total efficiency has a direct effect on how many wind turbines which is needed in the wind farm to produce enough hydrogen or ammonia. Given the high cost per wind turbine, it is favourable to reduce the number of wind turbines as much as possible. As shown in table 1, the two cases where hydrogen is used have higher total efficiencies than the two cases with ammonia, which leads to a need of fewer wind turbines.

*Table 1 Total efficiency*

| Case | Total efficiency (see appendix 6) | Number of wind turbines |
|---|---|---|
| **Hydrogen at 700 Bar** | 35.2 % | 17 |
| **Hydrogen at 350 Bar** | 37.1 % | 17 |
| **Ammonia ICE** | 22.3 % | 22 |
| **Ammonia FC** | 25.5 % | 21 |

When deciding between Case 1 and Case 2, with storage at 700 Bar and 350 Bar respectively, there are several factors to consider. As mentioned, table 1 shows that the two cases using hydrogen have a higher total efficiency than the two cases with ammonia. It also shows that a system where hydrogen is stored at 350 Bar has a slightly higher efficiency than a system where the hydrogen is stored at 700 Bar. This can be explained by the lower compression efficiency when compressing to 700 Bar compared to 350 Bar. In addition, both price and space are key factors when deciding between the two alternatives. By compressing the hydrogen to 700 Bar, it gets a higher density as mentioned in chapter 4, and therefore requires less space when stored. On the other hand, an increase in pressure requires tanks made from more costly materials as mentioned in chapter 4. This will lead to higher investment costs. It is assumed that the combination of lower storage costs and potentially using fewer wind turbines due to the higher efficiency in case 2 outweigh the benefits of saving space by using higher pressure. The next section of this report will therefore focus on hydrogen stored at 350 Bar. Furthermore, calculations will be made for ammonia ICE as well to illustrate differences in storage needs and cost.

## 5.2 Power from wind

In the process of making an overview of this kind of system, it is necessary to know how much power wind generates, and when it is generated. As discussed earlier, it is intended that wind turbines will power a platform, and in periods of too low or too high wind speeds the power will come from stored hydrogen or ammonia. By using gathered wind speeds from an entire year and a power curve from a chosen wind turbine it is possible to calculate the power output at any given time.

### 5.2.1 Wind measurements

To gather information on the wind speeds, “Norsk klimaservicesenter” is used.[49] The location that is chosen for the wind measurements is the gas platform Troll A, which is as shown in figure 18, located in the northern parts of the North Sea. The data gathered from “Norsk klimaservicesenter” shows the wind speeds through 2019 with one-hour intervals. A program called Windographer is then used to utilize the wind data.[50]


*Figure 18 Overview of continental shelf [2]*

### 5.2.2 Windographer

Windographer is a program which is used to analyse wind data. The data is imported into the program as an Excel file. Windographer has several use cases, however in this project the hourly power production from a wind farm is a necessity for further calculations. As mentioned earlier, it is necessary to have both wind speeds and a power curve from a wind turbine to calculate power output. Inside

Windographer there is a wind turbine library with several different turbines with different power outputs. The largest turbine in the library is a 10 MW turbine called Windtec Seatitan. It is assumed that a project of this size will use 12 or 15 MW turbines but given that the Windtec Seatitan is the largest turbine in the library, this is used.

### 5.2.3 Windtec Seatitan

The Windtec Seatitan is a 125-meter-high wind turbine with a rotor diameter of 190 meters. The cut-in wind speed is between 3 and 4 m/s, the rated wind speed is around 11 m/s and the cut-out speed is 25 m/s[51] as shown in figure 19 The turbine has, as mentioned, a rated power of 10 MW. When the power curve is applied to the measured wind speeds inside Windographer, a gross capacity factor of 45% is calculated. The program adds a loss factor of around 16% where wake effect, availability losses, turbine performance losses and electrical losses is included. This results in a net capacity factor of approximately 38%. The loss factor therefore also results in maximum power output being reduced to 8,4 MW.

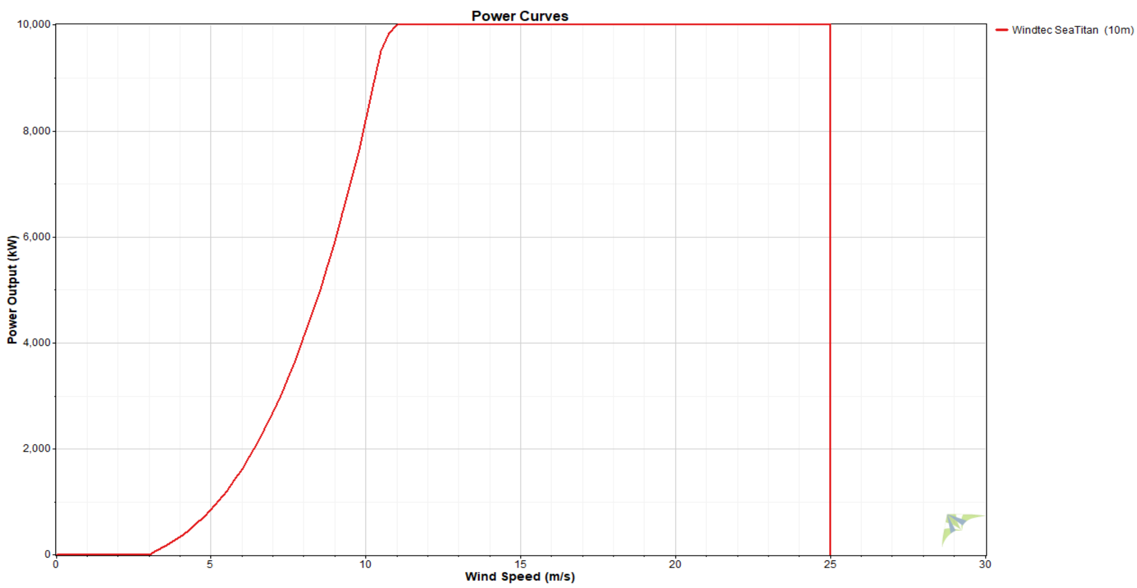


*Figure 19 Power curve*

## 5.3 Power from hydrogen

The purpose of obtaining the hourly power production from the wind farm is to calculate the amount of stored hydrogen which is necessary to power the platform at times where the wind power is not sufficient, as well as the required capacity of the wind farm. In situations where the wind speed is either lower than the cut-in speed or higher than the cut-out speed, the power output will be zero, and the platform will be 100% powered from hydrogen. At times where there is insufficient power delivery from the wind farm and it can only deliver a certain percentage of the power demand, the rest will be provided from the hydrogen.

The hourly production which is calculated in Windographer is imported back into Excel. By multiplying the power output from one turbine by the number of turbines in the wind farm, the total power output is calculated. The platform in this project is a 40 MW installation, and it is assumed that the power demand is consistent due to a lack of accurate data. Because of this, 40 MW is deducted from the total power output each hour. The result of this is a delta wind power which shows hourly surplus and shortage of wind power as illustrated in figure 20.

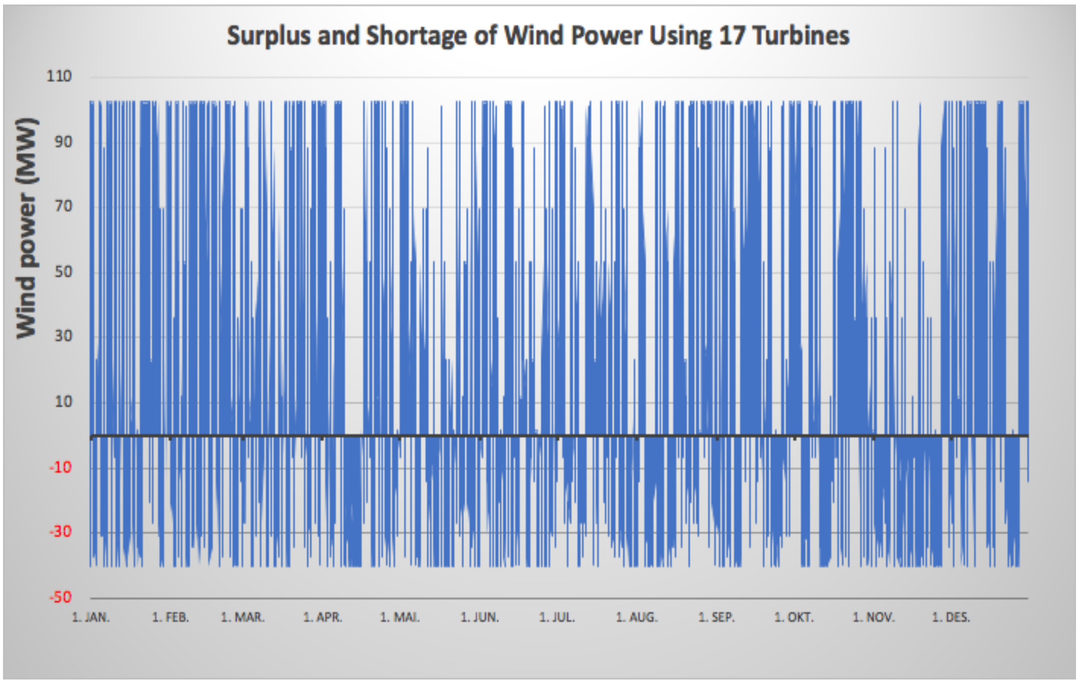


*Figure 20 Surplus and Shortage of Wind Power Using 17 Turbines*

The next step is to use the surplus and shortage of wind power, the efficiencies for production and usage of hydrogen, and the gravimetrical energy density to calculate either produced or used hydrogen per hour. The efficiencies for production and usage are calculated from the point where the power comes out of the wind turbine, and to the point when the hydrogen has been converted to usable electricity. The efficiencies of the individual processes are shown in table 2, together with the total energy efficiency for the hydrogen system. For this scenario it is assumed that the gravimetrical energy density is 33,33 kW/kg and the density for hydrogen at 350 Bar is 21 kg/m$^3$.

*Table 2 Hydrogen Efficiency*

| Part | Efficiency |
|---|---|
| Seawater desalination | 0,99 [52] |
| Electrolysis | 0,7 [21] |
| Compression | 0,94 [29] |
| **Efficiency hydrogen production 350 bar** | **0,65** |
| | |
| Fuel cell | 0,6 [21] |
| DC/AC inverter | 0,95[53] |
| **Efficiency hydrogen usage** | **0,57** |
| | |
| **Total system efficiency** | **37,1 %** |

To be able to determine the needed capacity of the hydrogen storage, as well as the production- and usage facilities for hydrogen, it is necessary to know how much hydrogen is stored at any given time. By taking the amount of produced, and used, hydrogen per hour and putting these into a cumulative table, it is possible to get a visualization of the amount of stored hydrogen throughout the year. This cumulative table is then visualized as two line charts, where one chart shows weight, and the other shows volume of the stored hydrogen, as shown in figure 21 and 22 respectively. Both graphs show a scenario of year one, where the storage tanks start empty. It is then assumed that the amount of stored hydrogen at the end of year one represents the amount of stored hydrogen at the start of year two.

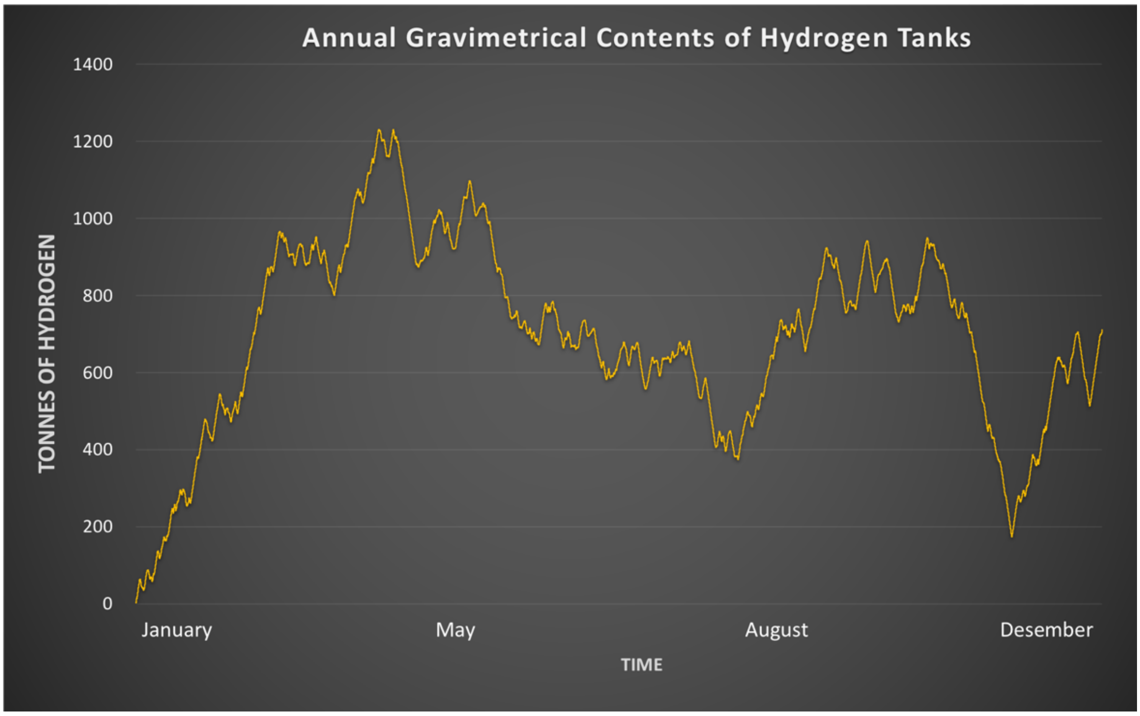


*Figure 21 Annual Gravimetric Contents of Hydrogen Tanks*

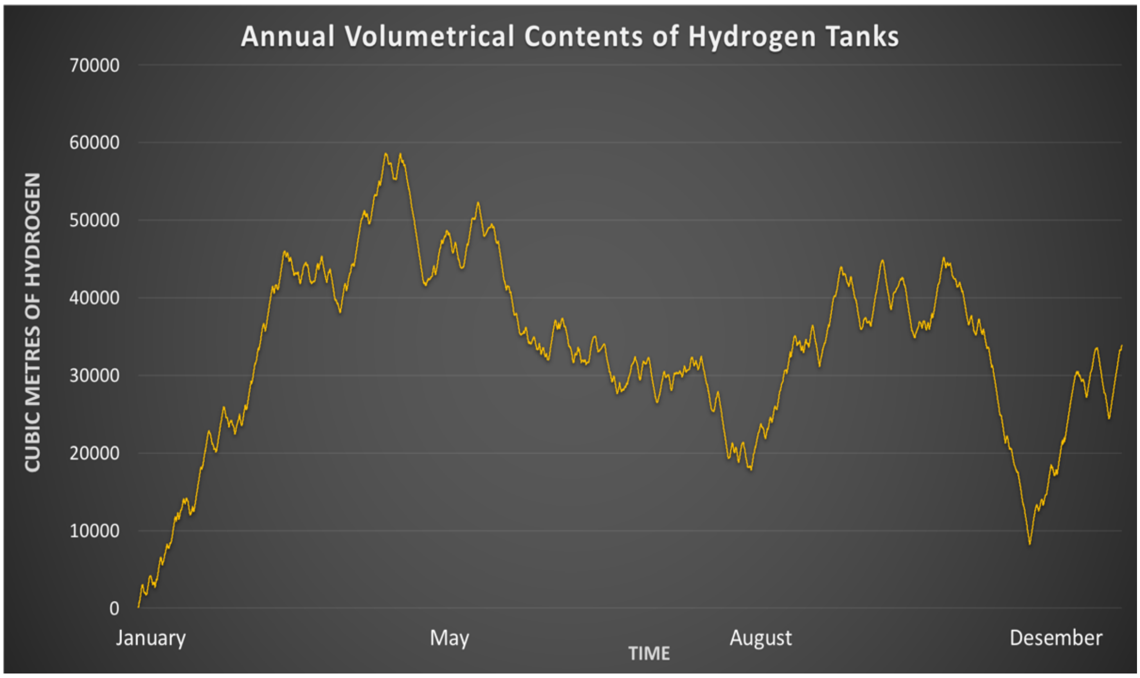


*Figure 22 Annual Volumetric Contents of Hydrogen Tanks*

By taking the highest number in the cumulative table it is possible to estimate the amount of storage capacity which is needed. In this case the maximum amount of stored hydrogen is around 1,200 tons, as shown in figure 21, which corresponds to a volume of around 60,000 cubic meters as shown in figure 22. Further, this means a need for around 30,000 storage tanks supplied by Umoe as described in the background chapter. This is as mentioned a year one scenario, and since it is assumed that the stored amount of hydrogen at the end of the year will represent the starting amount in year two, the excess hydrogen can then be sold, or more tanks can be installed. Further, the required capacity of electrolysers and fuel cells are calculated. By taking the number of produced kilograms of hydrogen per hour at peak power output from the turbines, it is possible to get an estimation of the required production. As shown in table 3, the required production from the electrolysers in this case is 2,009 kg/h of hydrogen. This further corresponds to an electrolysers capacity of 96 MW if an electrolysers efficiency of 70% is used. When deciding the capacity of the fuel cell it is assumed 100% power from the fuel cell in periods when there is zero output from the wind farm. It is further assumed that the fuel cells will operate at an 80% load due to this being assumed to give the highest efficiency. The required capacity can then be calculated by the following equation where 40,000 kW is the required power to the platform, 0,8 is the load factor on the fuel cell and 0.95 is the efficiency of the DC/AC inverter:

$$Required\ capacity\ FC = \frac{40{,}000\ kW}{0.8 * 0.95} = 52{,}632\ kW$$

The required fuel cell capacity is 52,632 kW. As shown in table 3, this corresponds to a hydrogen usage of 2,105 kg/h given the efficiencies used in this case.

*Table 3 Electrolyser and Fuel Cell Capacity*

| **Electrolyser capacity (kg/h)** | **2,009** |
|---|---|
| **Fuel cell capacity (kg/h)** | 2,105 |

The line charts can then help to optimize the system by showing the implications of increasing or decreasing the size of the wind farm, in addition to what implications an increase or decrease in efficiency will give. Given that this is a costly project, it is beneficial to find the right ratio of wind and hydrogen use to limit costs as much as possible. An increase in the size of the wind farm will increase the total power output and reduce the need for hydrogen storage, as well as reducing the required electrolyser and fuel cell capacity. On the other hand, it will increase the cost of the wind farm. As shown in figure 23 the system in this report gets 31 % of its annual power from hydrogen with the remaining power coming directly from the wind farm.

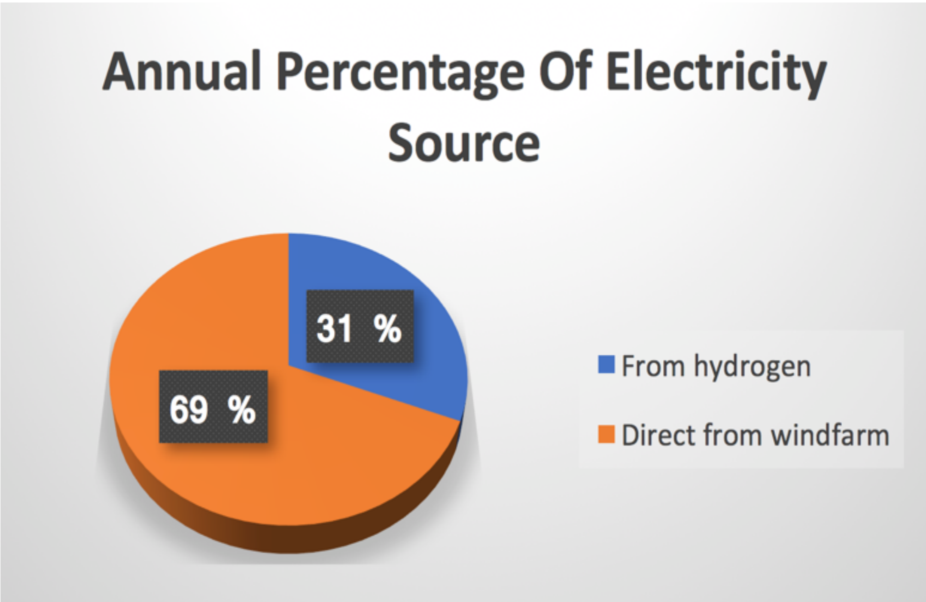


*Figure 23 Annual Percentage of Electricity Source (hydrogen)*

## 5.4 Power from ammonia

Like the scenario in the previous section where hydrogen was used, it is essential to find the surplus and shortage of wind power at any given time when using ammonia. As shown in chapther 5.1.5 this scenario uses 22 wind turbines at 10 MW each compared to the 17 turbines used in the previous section. Like the hydrogen scenario, 40 MW is constantly subtracted from the total output of wind power. This results in the surplus and shortage of wind power as shown in figure 24.

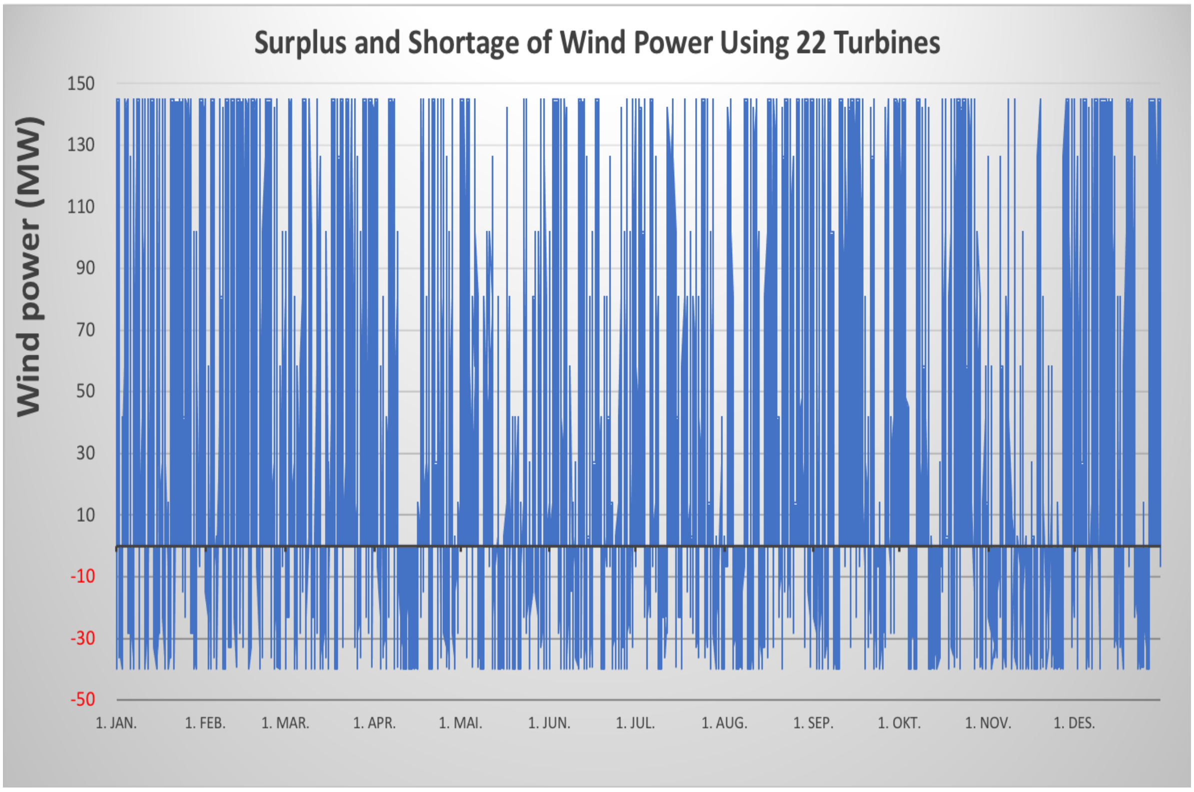


*Figure 24 Surplus and shortage of wind power with 22 turbines*

The next step is to use the surplus and shortage of wind power together with the efficiencies for production and usage, as well as the gravimetrical energy density of ammonia to calculate produced and used ammonia at any given time. The efficiencies of the individual processes are shown in table 4 together with the total energy efficiency for the ammonia system. It is assumed an energy density of 5.22 kwh/kg and a density of 636 kg/m$^3$, the high density is due to the assumption of subsea storage under 70m.[54] The efficiency for compression is uncertain and the only source of loss is assumed to be the pumps which are pumping the ammonia down to the ocean floor. Therefore, a number of 0.97 was assumed after conversation with industry.

*Table 4 Ammonia Efficiency*

| Part | Efficiency |
|---|---|
| Seawater desalination | 0,99 [52] |
| Electrolysis | 0,7[21] |
| Haber-Bosch | 0,8 [42] |
| Compression | 0,97 |
| **Efficiency ammonia production** | 0,54 |
| | |
| ICE | 0,45 [55] |
| Generator | 0,97 [55] |
| DC/AC grid inverter | 0,95 [53] |
| **Efficiency ammonia usage** | 0,415 |
| | |
| **Total system efficiency** | **22,3%** |

As in the previous section it is necessary to know how much ammonia is stored at any given time. The calculated amount of produced and used hydrogen is put into a cumulative table with two graphs showing annual gravimetric and annual volumetric contents. The graphs are shown below with figure 26 illustrating annual gravimetric contents and figure 26 showing annual volumetric contents. Similar to the scenario with hydrogen, both graphs show a year one scenario where the tanks start empty, and the amount of stored ammonia at the end of the year represents the starting point in year 2.

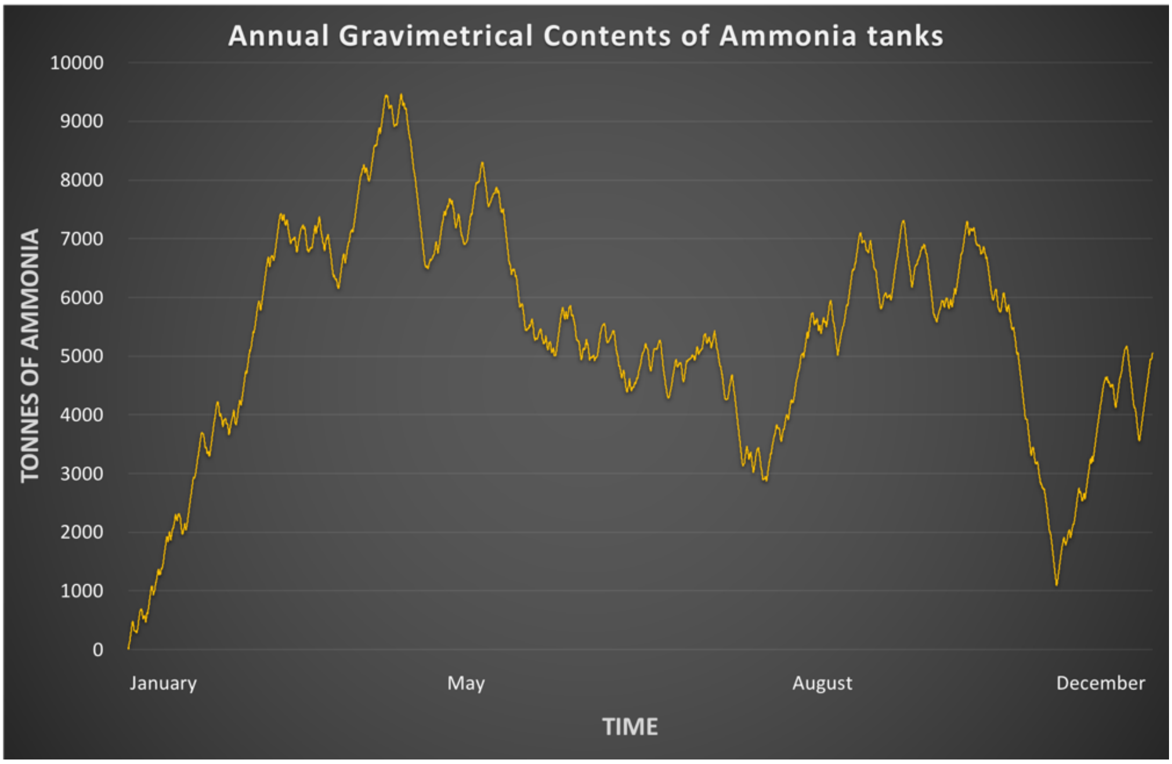


*Figure 25 Annual Gravimetric Contents of Ammonia Tanks*

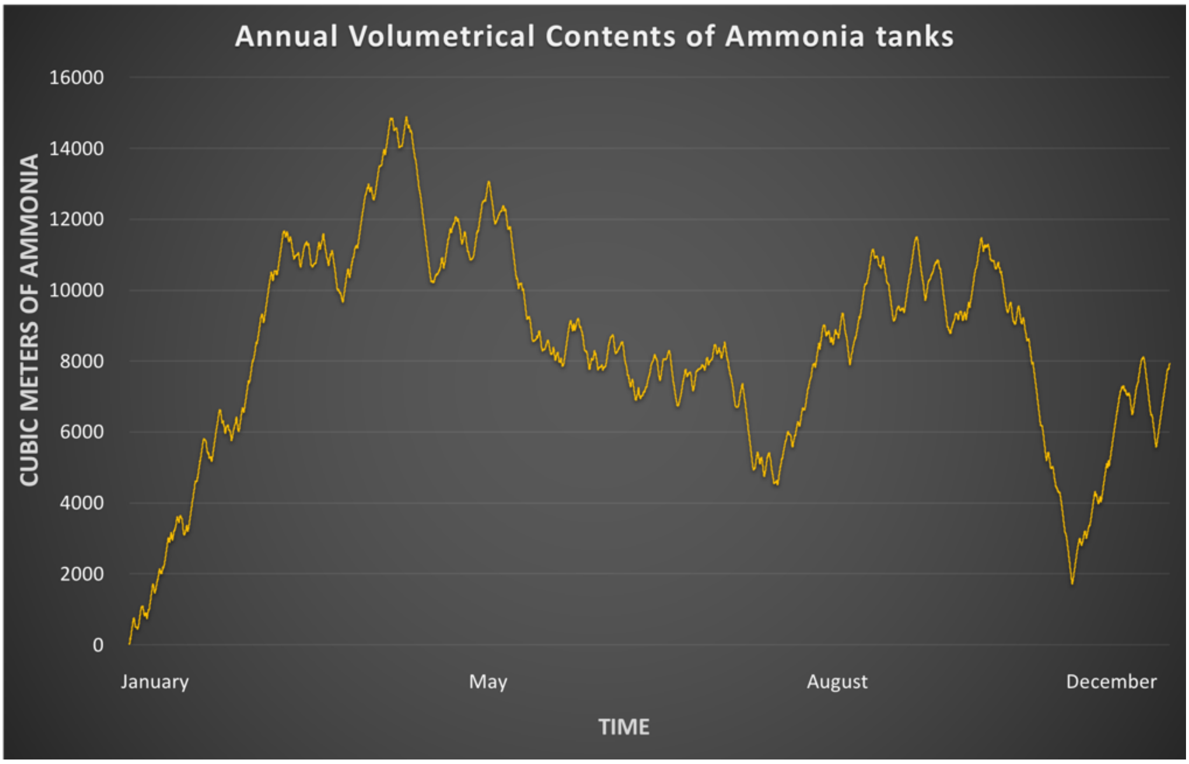


*Figure 26 Annual Volumetric Contents of Ammonia Tanks*

As done in the hydrogen scenario, the highest amount of stored ammonia is found in the graphs above. Based on this it is assumed a necessary storage capacity of around 9,500 tons of ammonia as shown in figure 25. This further corresponds to around 15,000 cubic meters as shown in figure 26. If the ammonia is then stored in NOV´s storage solution, which is described in chapter 4.3.4.3, 1.5 tanks would be required. The required ammonia production and ammonia usage per hour is, as shown in table 5 estimated to be 14,718 kg/h and 18,550 kg/h respectively.

*Table 5 Maximum Ammonia Production and Usage*

| **Maximum ammonia production (kg/h)** | **14,718** |
|---|---|
| **Maximum ammonia usage (kg/h)** | 18,550 |

Given that liquid ammonia has a hydrogen weight fraction of 17.65 weight% and assuming 100% conversion to ammonia, the required electrolyser capacity is a production of 2,598 kg/h. [56] This is calculated below:

$$Required\ hydrogen\ production = 14{,}718.7\frac{kg}{h} * 0.1765 = 2{,}598\frac{kg}{h}$$

The production of 2,598 kg/h correspond to 124 MW of electrolysers if an electrolyser efficiency of 70% is used. Similar to the hydrogen scenario, a 40 MW power output is needed at the platform. The ammonia ICE achieves its highest efficiency, which is listed in the table 4 when running at 85%

load.[55] In addition to this there are efficiency losses in the generator and the AC/DC inverter. The required rated power of the ICE is calculated as following, with 0.97 and 0.95 being the generators and the AC/DC inverters efficiency respectively:

$$Required\ power\ ICE = \frac{40{,}000\ kW}{0.85 * 0.97 * 0.95} = 51{,}068\ kW$$

Like the system with hydrogen, a chart showing the distribution of where the electricity supplied to the platform comes from is made as shown in figure 27. It shows that 72 % of the power comes directly from the windfarm while 28% comes from the use of ammonia.

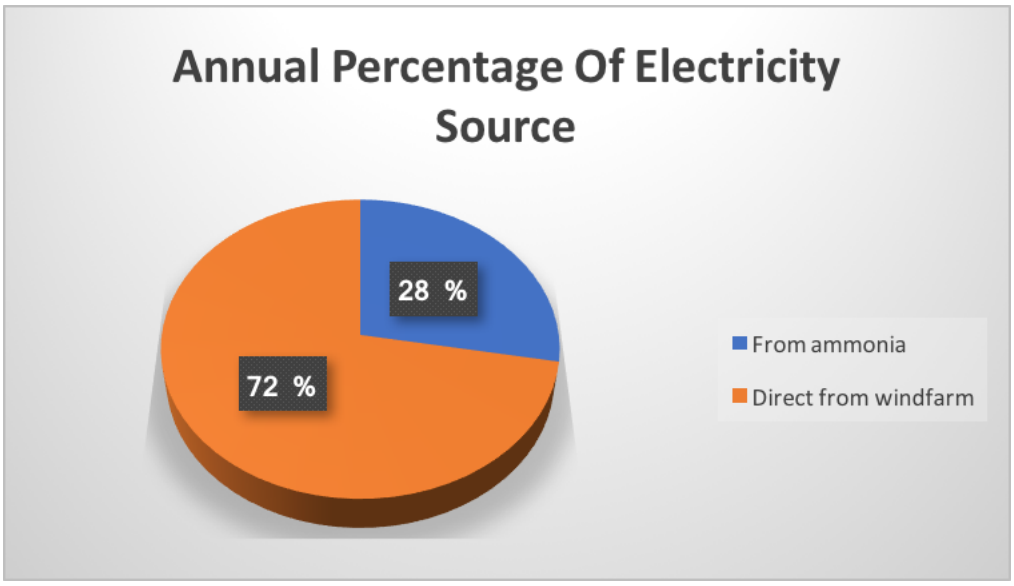


*Figure 27 Annual Precentage of Electricity Source*

## 5.5 Sensitivity analysis hydrogen 350 Bar

As mentioned earlier, the line charts in the previous sections can show the implications of varying the size of the wind farm and altering the efficiencies. To illustrate the effects either increasing or decreasing the efficiencies have, a sensitivity analysis has been made. The baseline for this analysis will be hydrogen storage at 350 Bar, as chosen in chapter 5.1, with an additional low estimate as well as a theoretical maximum scenario where the theoretical maximums for each efficiency are used. In areas where the efficiencies are without an interval or higher/lower estimates cannot be found, the efficiencies will be the same across the three scenarios. All scenarios are set as a year one scenario where the hydrogen tanks start empty, and the number of wind turbines is set so that the contents of the tanks do not reach zero. For all scenarios, it is assumed that the gravimetrical energy density is 33,33 kWh/kg and the density of hydrogen at 350 Bar is 23 kg/m$^3$.

### 5.5.1 Low estimate

Given that most of the efficiencies used have a significant interval between the highest and lowest estimate, it is beneficial to show the implications of this uncertainty. In the low estimate the efficiencies shown in table 6 will be used, and this represents the lower sides of the estimates. The efficiencies combine to a total efficiency of 24,3%.

*Table 6 Low Efficiency Hydrogen*

| Part | Efficiency |
|---|---|
| Seawater desalination | 0,99[52] |
| Electrolysis | 0,6 [21] |
| Compression | 0,91[29] |
| **Efficiency hydrogen production** | **0,54** |
| | |
| Fuel cell | 0,5[21] |
| DC/AC inverter | 0,9[53] |
| **Efficiency hydrogen usage** | **0,45** |
| | |
| **Total system efficiency** | **24,3 %** |

### 5.5.2 High estimate

The estimates in this scenario are the same as in the previous chapter, and as mentioned the estimates of the chosen efficiencies have a significant interval. In this current scenario, the efficiencies used are in the higher parts of the intervals, while they still are assumed to be realistic. The efficiencies shown in table 7 combine to a total efficiency of 37,1%.

*Table 7 High Efficiency Hydrogen*

| Part | Efficiency |
|---|---|
| Seawater desalination | 0,99[52] |
| Electrolysis | 0,7 [21] |
| Compression | 0,94[29] |
| **Efficiency hydrogen production** | 0,65 |
| | |
| Fuel cell | 0,6 [21] |
| DC/AC inverter | 0,95[53] |
| **Efficiency hydrogen usage** | 0,57 |
| | |
| **Total system efficiency** | 37,1 % |

### 5.5.3 Theoretical maximum

In this scenario, the efficiencies used are the theoretical maximums for each part of the system. These efficiencies are not considered to be achievable with today's technology, but this scenario together with the two other scenarios shows the effects altering the efficiencies provide. The efficiency is shown in table 8 combine to a total efficiency of 70,4%.

*Table 8 Theoretical Maximum Hydrogen Efficiency*

| Part | Efficiency |
|---|---|
| Seawater desalination | 0,99[52] |
| Electrolysis | 0,93[57] |
| Compression | 0,97[29] |
| **Efficiency hydrogen production** | 0,89 |
| | |
| Fuel cell | 0,83[58] |
| DC/AC inverter | 0,95[53] |
| **Efficiency hydrogen usage** | 0,79 |
| | |
| **Total system efficiency** | 70,4 % |

### 5.5.4 Comparison

By comparing the total efficiencies together with the number of turbines for each scenario, it is easy to illustrate the effects of increasing or decreasing the efficiencies. As shown in figure 28 the low estimate scenario, the high estimate scenario, and the theoretical maximum scenario utilize 21, 17 and 13 wind turbines respectively, which in this case means a wind farm capacity off 210, 170 and 130 MW.

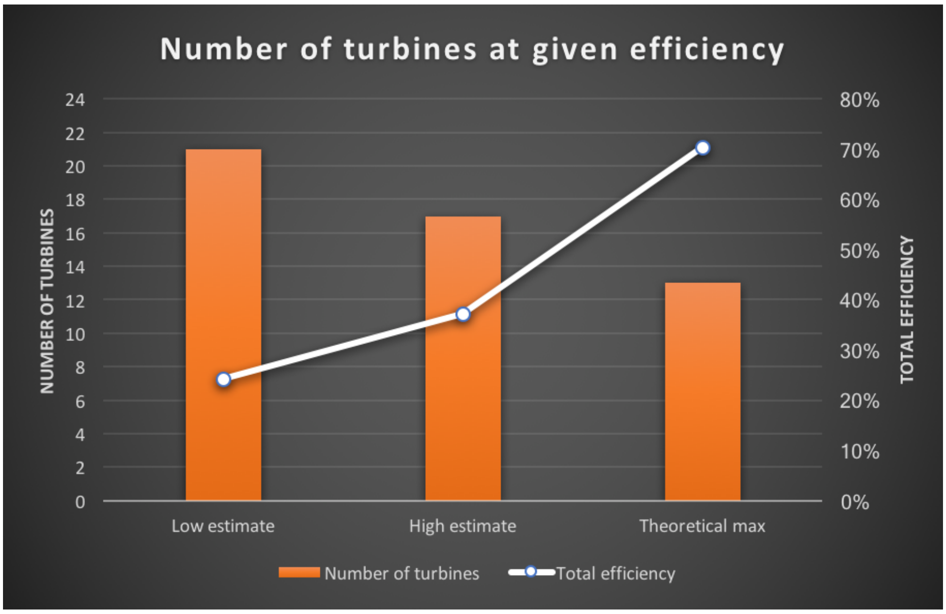


*Figure 28 Number of turbines at given efficiency*

When assuming the calculated net capacity factor of 0.38, it is possible to calculate how many megawatts of wind is needed to cover the power usage of the platform. This will be done by using the following equation where 40,000 kW is the power demand from the platform and 0.38 is the net capacity factor:

$$Power\ demand\ windfarm = \frac{40{,}000\ kW}{0.38} = 105{,}263\ kW \approx 105\ MW$$

This means that to cover the power demand for the platform during year one, the wind farm needs to have a capacity of 105 MW which in this case relates to having 11 wind turbines of 10 MW each. The problem with this kind of calculation, however, is that it doesn't consider intermittency, but only calculates produced power. This leads to the need of some sort of energy storage. This also means that the difference in number between the calculated required capacity above, and the number of wind turbines needed is how many turbines which is needed to produce hydrogen. It is therefore preferable to reduce the number of turbines as much as possible. Furthermore, the increased efficiency leads to lower required storage capacity as shown in figure 29. This is due to a more efficient utilization of the hydrogen. It is also worth mentioning that the three different scenarios have a different amount of hydrogen left in the tanks at the end of the year, which results in the need to sell hydrogen or invest in larger tanks to avoid curtailment.

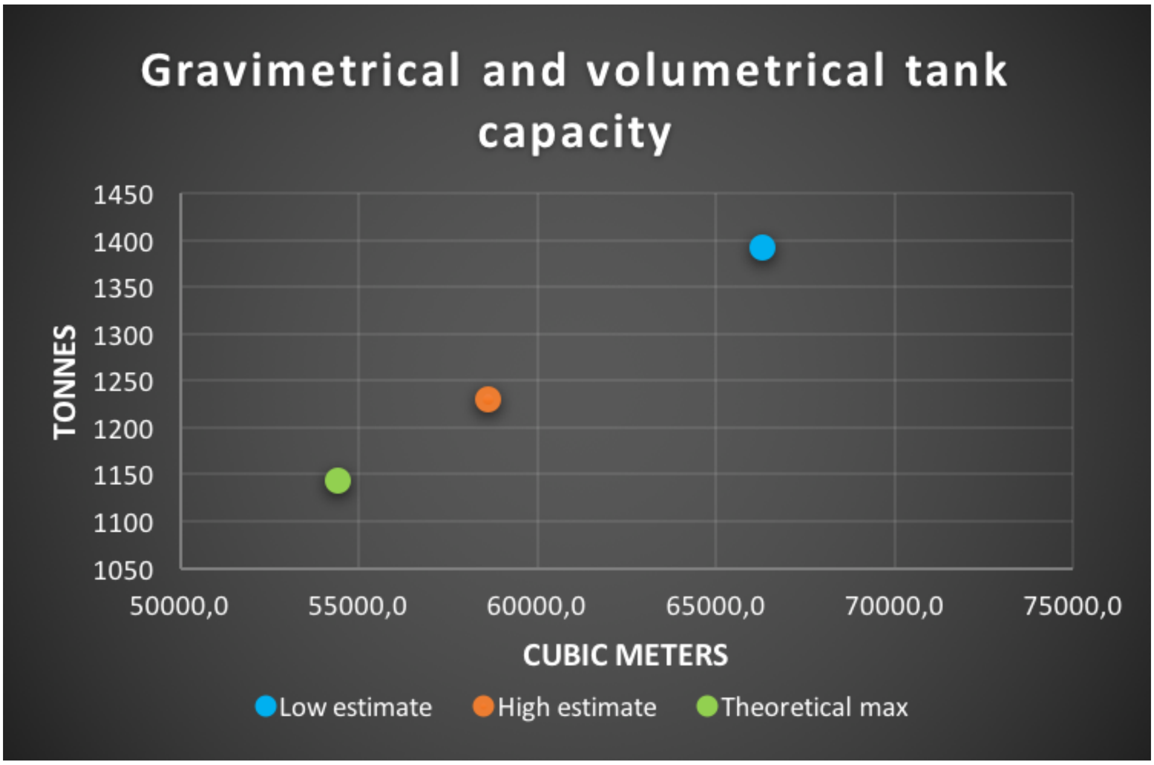


*Figure 29 Gravimetrical and volumetrical tank capacity*

# 6 Results of techno-economic analysis

This chapter is analysing the economics for a total electrification of the 40 MW platform. The section will study the Net Present Value, total investment cost and find the main cost drivers. Given the immaturity of the field of research, some of the costs of the individual components proved hard to find. Consequently, some estimates will be used. Although other similar projects have gained financial support by Enova, this analysis will not take such into account due to the uncertainty regarding if the project would obtain this support.

## 6.1 Investment cost

The analysis has set the investment decision to either in 2020 or 2030 with two different investment scenarios. Either a system with hydrogen and a fuel cell or ammonia and an internal combustion engine. Case 2 and case 3 from the previous chapter.

*Table 9 Investment Cost*

| Investment | 2020 Hydrogen FC | 2020 Ammonia ICE | 2030 Hydrogen FC | 2030 Ammonia ICE |
|---|---|---|---|---|
| Alkaline Electrolyzer | NOK 1 306 250 000 | NOK 1 705 000 000 | NOK 688 750 000 | NOK 899 000 000 |
| Ammonia Combustion Engine | - | NOK 267 948 718 | - | NOK 241 153 846 |
| Ammonia Production; H-B | - | NOK 96 379 163 | - | NOK 86 741 246 |
| Offshore Platform | NOK 162 450 000 | NOK 212 040 000 | NOK 146 205 000 | NOK 190 836 000 |
| PEM Fuel Cell | NOK 1 250 000 000 | - | NOK 750 000 000 | - |
| Salt Water Reverse Osmosis | NOK 6 156 000 | NOK 7 996 644 | NOK 5 848 200 | NOK 7 196 980 |
| Subsea Storage Ammonia | - | NOK 446 500 000 | - | NOK 401 850 000 |
| Subsea Storage Hydrogen | NOK 3 900 000 000 | - | NOK 3 510 000 000 | - |
| Windfarm | NOK 10 200 000 000 | NOK 13 200 000 000 | NOK 4 420 000 000 | NOK 5 720 000 000 |
| ***Total Investment*** | NOK 16 824 856 000 | NOK 15 935 864 524 | NOK 9 520 803 200 | NOK 7 546 778 072 |

Table 9 lists the different components that is needed for these scenarios, as well as their investment cost. Every cost is calculated from the appendix 3. Components that are not regarded as a mature technology and have no clear estimate for price reduction will have 10% reduction until 2030. This includes ammonia ICE, the offshore platform and the Saltwater Reverse Osmosis (SWRO). The rest of the components have a clear cost reduction that is addressed in appendix 3. Removal of the floating wind farm is not included in table 1 since this cost comes at the end of the scenario's lifetime. The cost of removal is set to 10000 NOK/MW [17]. The cost of "floating windfarm" includes: Offshore substation, export cables, onshore cables (supply + installation).[17] "Ammonia production; H-B" includes the capital cost for the H-B plant and Air Separator Unit (ASU). [59] The alkaline electrolysers and PEM fuel cell cost estimates were gathered from different sources listed in the appendix 3. For subsea storage and "ammonia combustion engine" the estimates where gathered from different companies from the industry and they are listed in the appendix 3. It's important to emphasize that the numbers used are estimates from the companies and not something that is tested and verified. Insignificant components without a major impact on the investment cost were excluded.

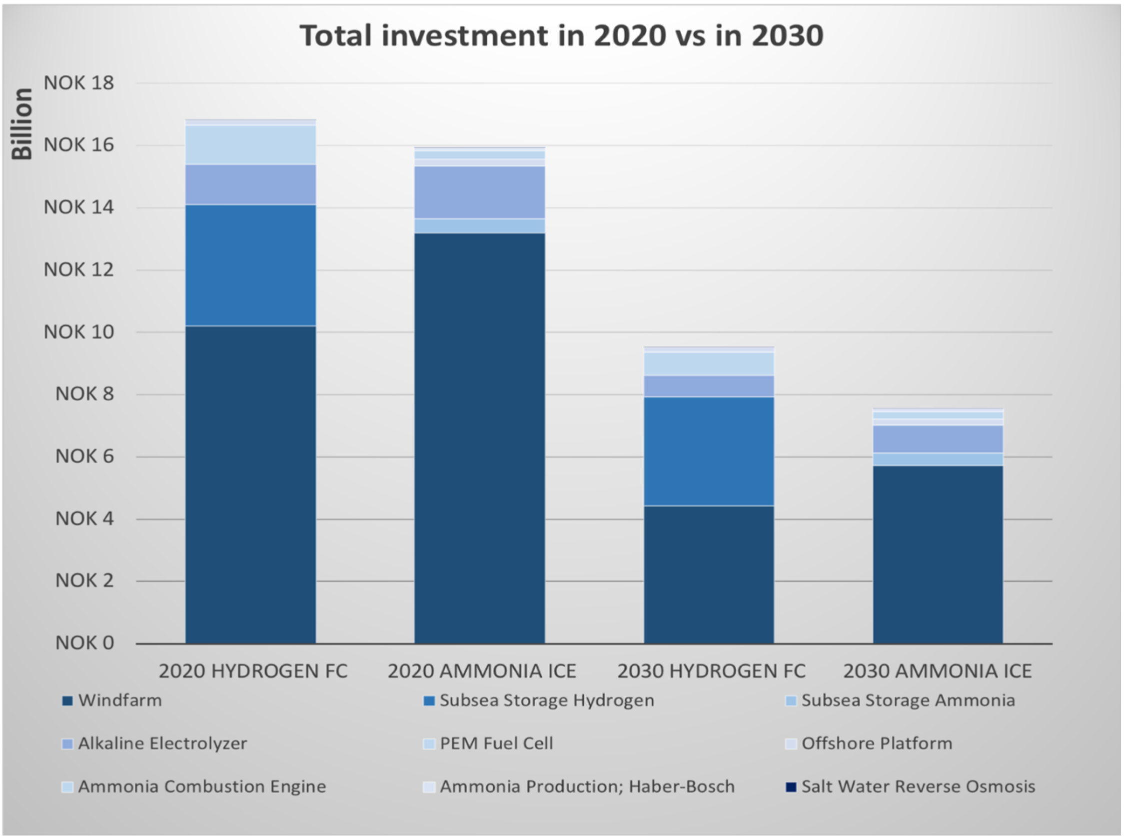


*Figure 30 Total Investment in 2020 vs in 2030*

Figure 30 is based on table 9 and compares the total investment costs of the different scenarios. The graph suggests that an investment in 2020 of an ICE with ammonia storage would cost approximately 16 billion NOK. This estimate would be three times the investment cost of Hywind Tampen.[60] The hydrogen system is calculated to have a cost of 1 billion more. The cost reduction towards 2030 comes mainly from the reduced cost of the floating wind farm, as it is expected a 56% cost reduction of floating wind from 2020 to 2030.[17]

## 6.2 Cost drivers

When studying cost drivers for a project, some components will probably be costlier than others. In this scenario, floating wind turbines is such a component. Graph 31 and 32 showcases clearly that the floating wind farm contributes to 61% and 83% respectively. Moreover, in every “cost drivers” graph the second-costliest component will be highlighted. For hydrogen FC 2020 this is the “subsea storage hydrogen” with 26% and for ammonia ICE 2020 this is the “alkaline electrolyser” with 11%

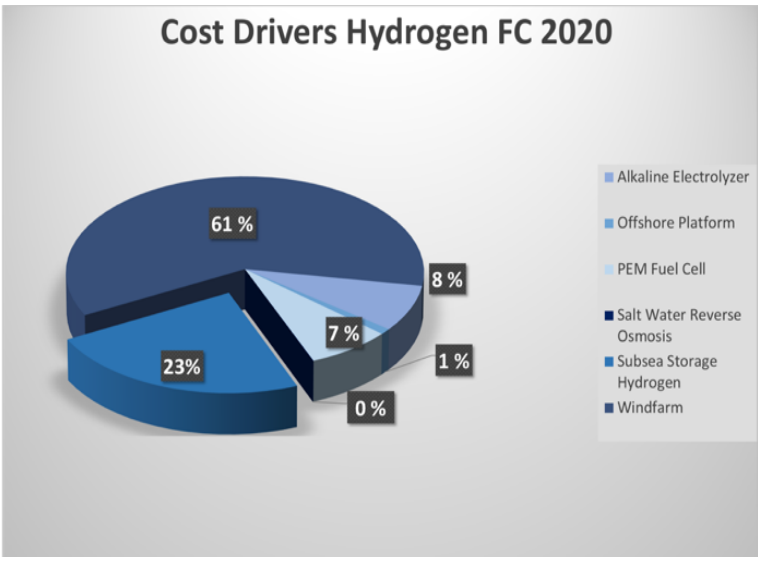


*Figure 32 Cost Drivers Hydrogen FC 2020*

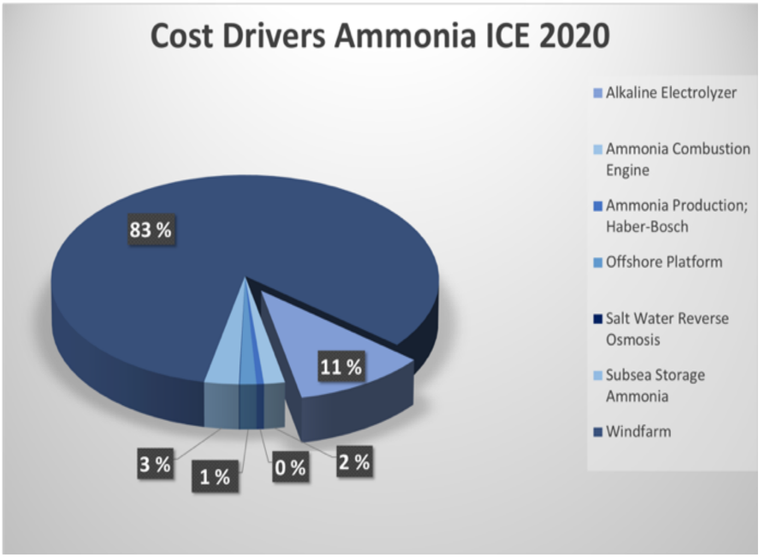


*Figure 31 Cost Drivers Ammonia FC 2020*

In 2030 the outcome is quite similar for ammonia ICE, where the floating wind farm will take the majority of the cost at 76%. The alkaline electrolyser will still be the second costliest component at now 12%. For hydrogen FC the outcome is quite different. This is due to the lack of knowledge regarding the cost reduction of the subsea storage. As mentioned, it is estimated a cost reduction of 10%, but this estimate is assumed to be conservative. The result is showcased in figure 34 and 35.

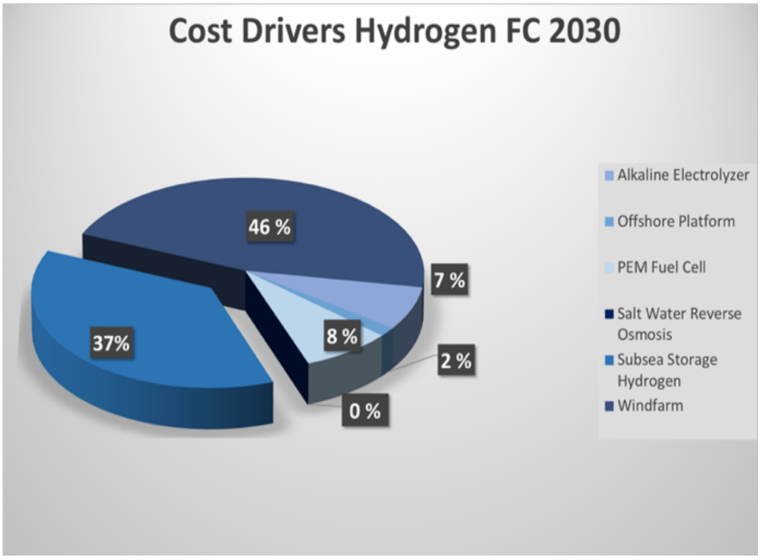


*Figure 34 Cost Drivers Hydrogen 2030*

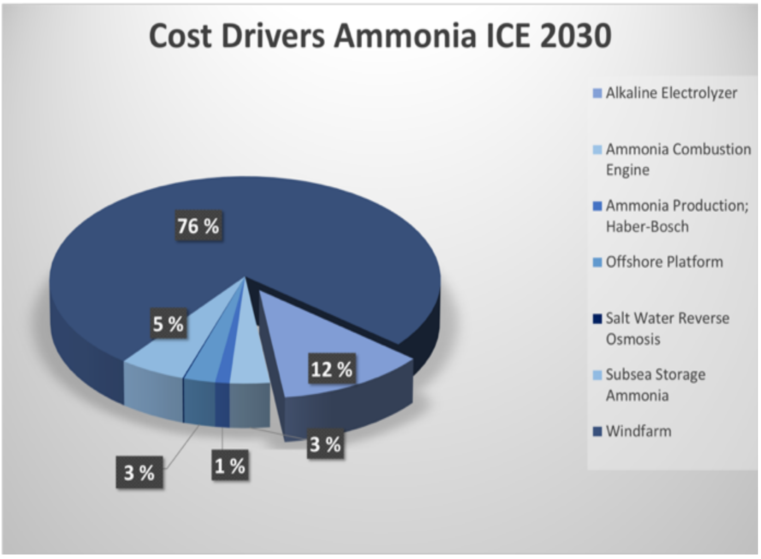


*Figure 33 Cost Drivers Ammonia 2030*

### 6.2.1 Lifetime expectancy

Critical for determining the Net Present Value (NPV) and understanding the economics of this project, is estimating the lifetime expectancy of the different components. The lifetime estimates will be the same in both 2020 and 2030 investment scenarios. In this scenario, it would be reasonable to conclude the project when the wind farm has to be removed, given that this component is the main cost-driver and would be most costly to remove.

The lifetime expectancy of a windmill is debatable. Multiconsult has a conservative estimate of 18 years in their report about Hywind Tampen.[17] Crown Estate Scotland and catapult offshore renewable energy said in the report "*Macroeconomic benefits of floating offshore wind in the UK*" that in 2018 the lifetime expectancy of a floating wind farm was 20 years, and in 2025 at the pre-commercial stage the lifetime expectancy was 25 years.[61] It is therefore, based on these facts, estimated that this floating wind farm will have a lifetime of 20 years.

Other components that needs to be taken into consideration when looking at lifetime expectancy, is the electrolyser and fuel cells. The system lifetime expectancy for both an alkaline electrolyser and a PEMFC is 20 years.[62] Shell estimates that an alkaline electrolyser stack lifetime expectancy is 60,000-90,000 hours, and for a PEM fuel cell stack the lifetime expectancy is 60,000 hours. [63] This suggests that the project will need a new set of stacks for the electrolyser and fuel cells approximately every 7 years for the hydrogen FC scenario. The ammonia ICE scenario would only need a new alkaline electrolyser stack since the scenario does not include a fuel cell. It is expected that the remaining components will endure throughout 20 years.

## 6.3 The economics of $CO_2$ and $NO_x$ emissions

To calculate the NPV, it is necessary to determine how much this scenario saves annually on removing greenhouse emissions. The earning comes from multiplying the saved emissions with the carbon and $NO_x$ price.

Production of electricity on a platform usually happens by burning natural gas in a gas turbine. Appendix 4 calculates the total amount of natural gas used, assuming that the platform is running at full capacity all year with a turbine efficiency of 30%, resulting in a consumption of 113 million $Sm^3$.[64] According to "Norsk olje og gass" the gas turbines on Troll are emitting 56 tons CO2/TJ natural gas. Unfortunately, it did not specify tonnes $NO_x$/TJ.[13] Assuming that natural gas holds 40 MJ/ $Sm^3$ [65] the platform would emit 257 000 tonnes CO2 each year appendix 4. Since "*Norsk olje og gass"* does not specify $NO_x$ emissions from a gas turbine, an estimate was calculated.

**Tabell 7.1: Utslipp til luft fra forbrenningsprosesser på permanent plasserte innretninger**

| Kilde | Mengde flytende brennstoff [tonn] | Mengde brenngass [Sm3] | CO2 [tonn] | NOx [tonn] | nmVOC [tonn] | CH4 [tonn] | SOx [tonn] | PCB [kg] | PAH [kg] | Dioksiner [kg] | Fallout olje ved brønntest [tonn] |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Fakkel | | 9 772 604 | 28 426 | 13,68 | 0,59 | 2,35 | 0,01 | | | | |
| Turbiner (DLE) | | | | 78,54 | | | | | | | |
| Turbiner (SAC) | 2 173 | 268 879 137 | 556 959 | 2 490,32 | 64,60 | 244,68 | 2,43 | | | | |
| Turbiner (WLE) | | | | | | | | | | | |
| Motorer | 98 | | 311 | 4,51 | 0,49 | | 0,10 | | | | |
| Fyrte kjeler | | | | | | | | | | | |
| Brønntest | | | | | | | | | | | |
| Brønnopprenskning | | | | | | | | | | | |
| Avblødning over brennerbom | | | | | | | | | | | |
| Andre kilder | | | | | | | | | | | |
| **Sum alle kilder** | **2 272** | **278 651 741** | **585 697** | **2 587,10** | **65,68** | **247,03** | **2,53** | | | | |

*Figure 35Emissions from Troll [13]*

Figure 35 shows how much the troll platforms emits annually. To find an estimation for $NO_x$ emissions from the platform in this project, the annual $NO_x$ emissions from the Troll field are divided by the fuel gas use. By multiplying this ratio with the fuel gas use from the platform in this project, an annually $NO_x$ emission of 1,050 tonnes are calculated as done below:

$$\frac{2{,}490\ Tonn\ NOx}{268{,}879{,}137\ Sm^3} * 113{,}398{,}058\ Sm^3 = 1{,}050\ Tonn\ NOx$$

The NPV will use a rounded estimate of 1,000 tons $NO_x$ per year.

Most techno-economic analyses, where the scenario affects greenhouse emissions, needs to estimate a carbon price. Because Norwegian regulations does not stipulate a mandatory carbon price for use in public socio-economic analyses, there is a need for an estimate.[66] Former oil and energy minister Kjell-Børge Freiberg told Adresseavisen in 2019 that "*Quotas and CO2 tax will continue to be the main instruments in climate policy on the Norwegian continental shelf*" .[67]

The main problem with estimating a carbon price is that it is unknown if the future price will aim for emission targets of the Paris agreement of 2°C, a more aggressive strategy of 1,5°C or take a conservative course of over 2°C. There is additionally a significant disagreement over the current estimates for a carbon price. The disagreement originates because of separate calculation methods, different technological development estimates and various emission targets.[17] Multiconsult has created a graph displaying the different paths carbon pricing can take. The graph has three different scenarios 2°C, 1.5°C, and a conservative estimate. This graph is in 2018 NOK.

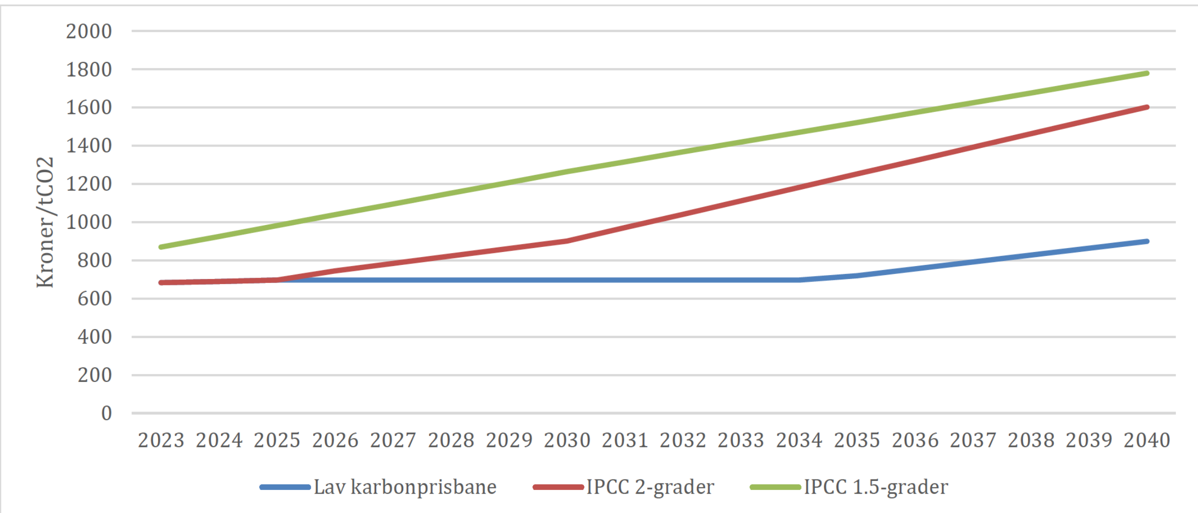


*Figure 36 Low, 1,5 degree and 2 degree carbon price forecast*

The Department of Energy & Climate Change has conducted "A brief guide to the carbon valuation methodology for UK policy appraisal" [12]. In this report, they made a low, medium, and a high estimate of future carbon prices. The graph is based on the assumption that exceeding 2030, a fully operating global carbon market imposing a single carbon value for economic appraisal, which reflects the costs required to achieve the EU long term target of restricting imminent climate change to 2°C. The same report also suggested that from 2050 and onwards, the carbon price would still rise with the same rate for multiple years. This will be taken into account when developing a sensitivity analysis which looks at an NPV that will last to 2060.

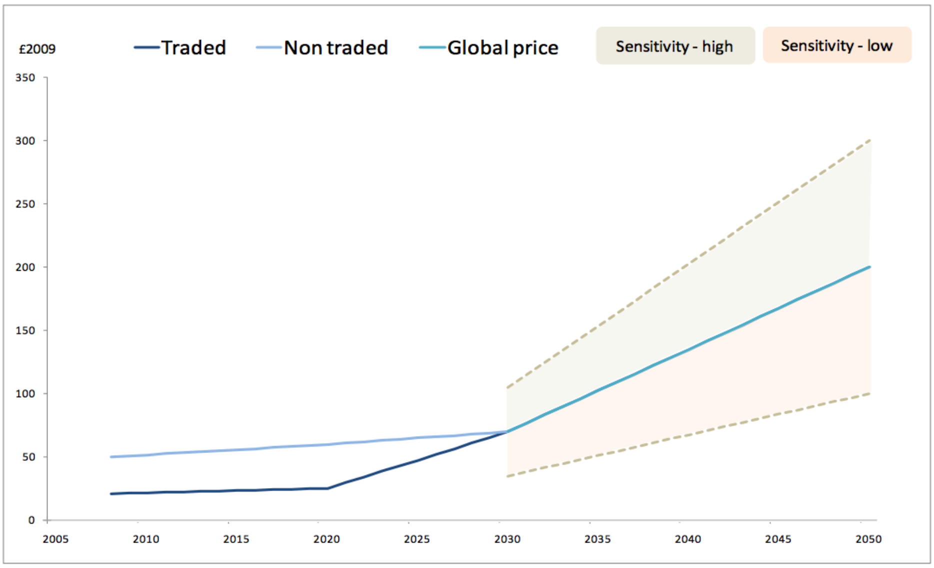


*Figure 37 a low, central, and high estimate of future carbon prices [12]*

Furthermore, Multiconsult also constructed a graph displaying the carbon price they used when calculating NPV for Hywind Tampen.[17] This graph shows the carbon price development of a 2°C target. This carbon price represents an average of 33 separate carbon price studies that are consistent with the two-degree target.

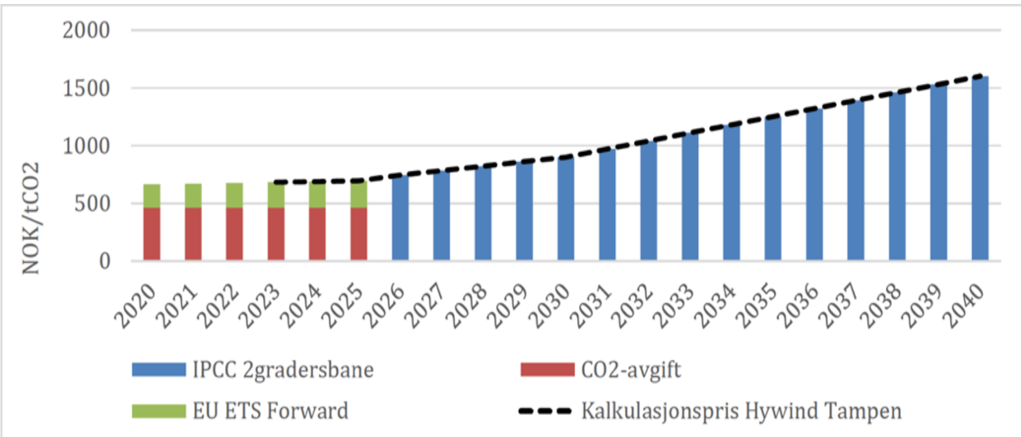


*Figure 38 Carbon Price from Hywind Tampen[17]*

Based on the previous graphs, figure 39 was made. It represents different carbon prices for a low, average, and high estimate for a carbon price. These carbon prices will be used when calculating the NPV for the different scenarios. Furthermore, it will be assumed that the carbon price will have the same trajectory onwards to 2060.

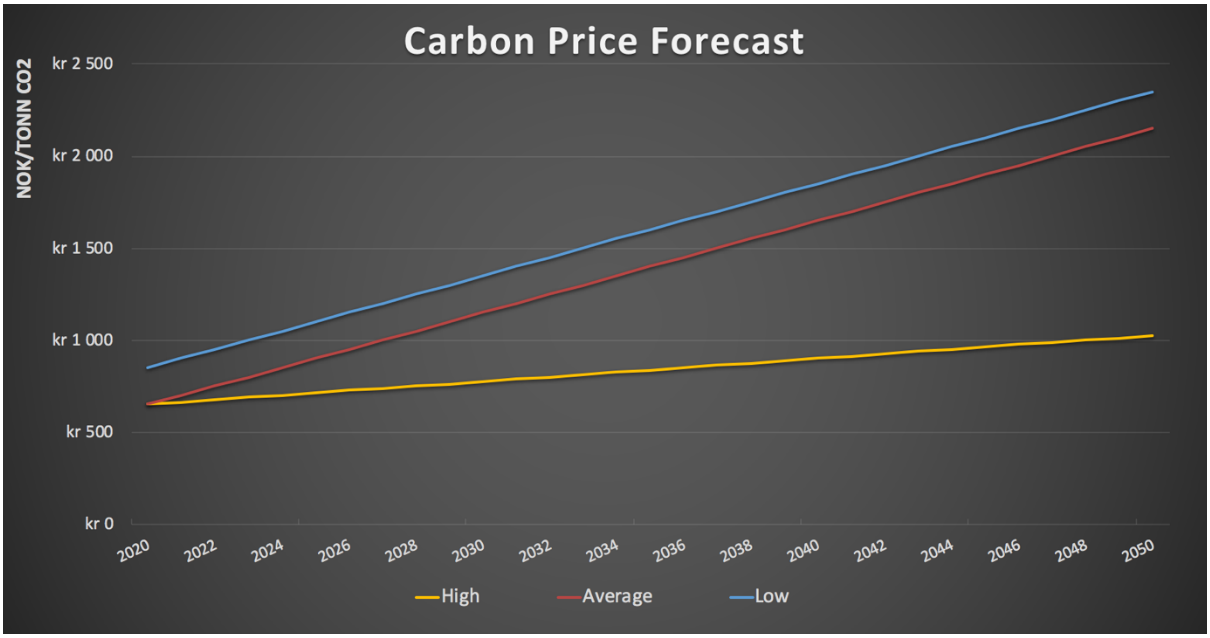


*Figure 39 Carbon Price Forecast*

There are not many studies discussing how the cost of $NO_x$ emissions will increase in the following years, and other studies have set the price as a constant.[17] Accordingly, this thesis will have the $NO_x$ price as a constant at 22 NOK/kg.[68]

### 6.3.1 Savings on natural gas

Since the entire electricity demand of the platform would originate from wind and hydrogen or ammonia, natural gas to generate electricity is not necessary. This opens the possibility to sell the gas that originally would be used for electricity production. Appendix 4 calculates that the platform would need approximately 113,398,000 $Sm^3$ per year as mentioned in the previous section.

The future price of natural gas in Europe is uncertain due to the market's volatility, but several estimates attempt to give a forecast. In 2017 the IEA published a World Energy Outlook, figure 40 is based on this report and shows a natural gas price constant at 20 EUR/MWh.

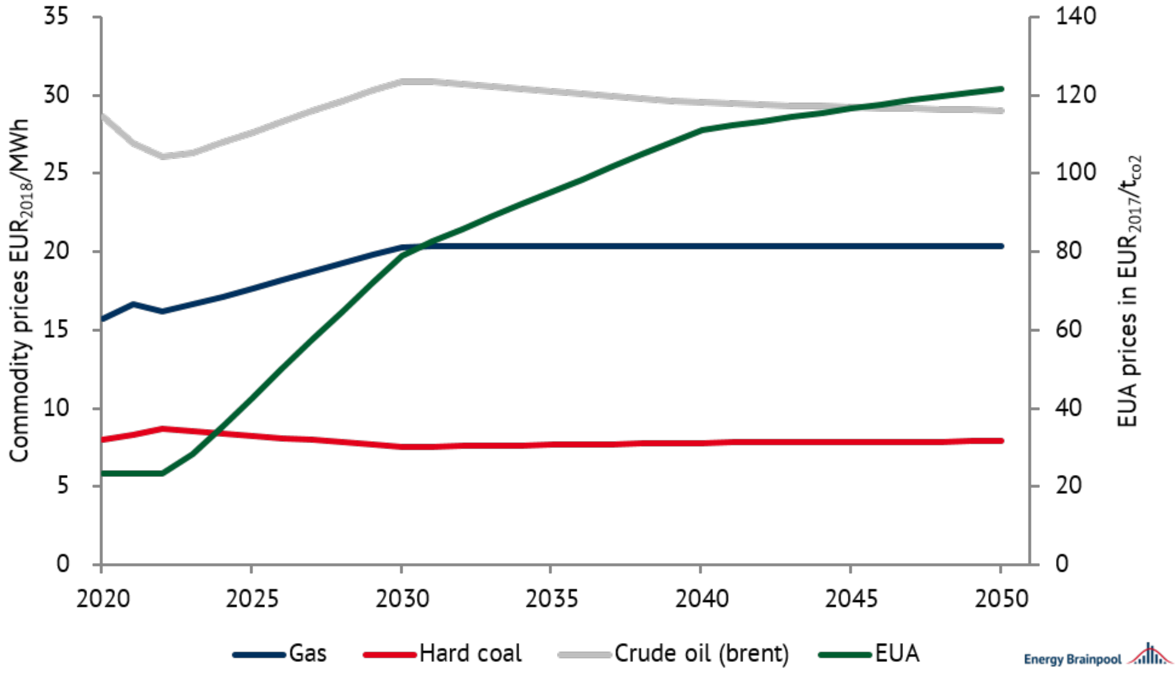


*Figure 40 Natural Gas Price Forecast [7]*

Multiconsult's report regarding Hywind Tampen presents a graph that shows historical prices, and THEMA's price estimates for natural gas delivered on the continent.[17] The gas price forecast is calculated as one of the long-term gas price forecasts for the World Bank and IEA from 2018. Figure 41 shows a gas price that is constant after 2030 at around 28 EUR/MWh.

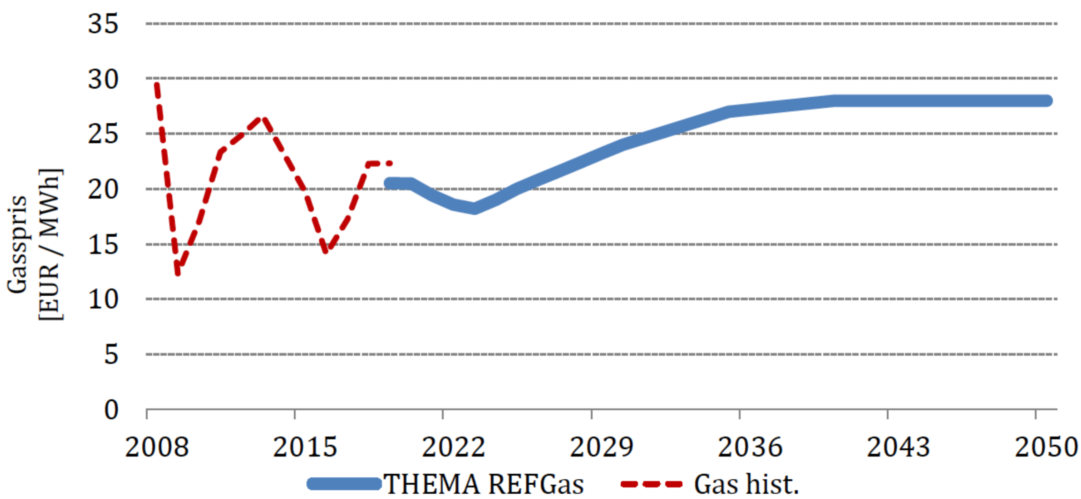


*Figure 41 Natural Gas Prices used in Multiconsults raport[17]*

Lastly, figure 42 is based on historic natural gas prices from 2000-2019, as well as estimates from the world bank from 2020-2030.[69] It was added a linear trend line to see how the prices may evolve onwards to 2050. In this estimate, the price would be constant at around 25 EUR/MWh.

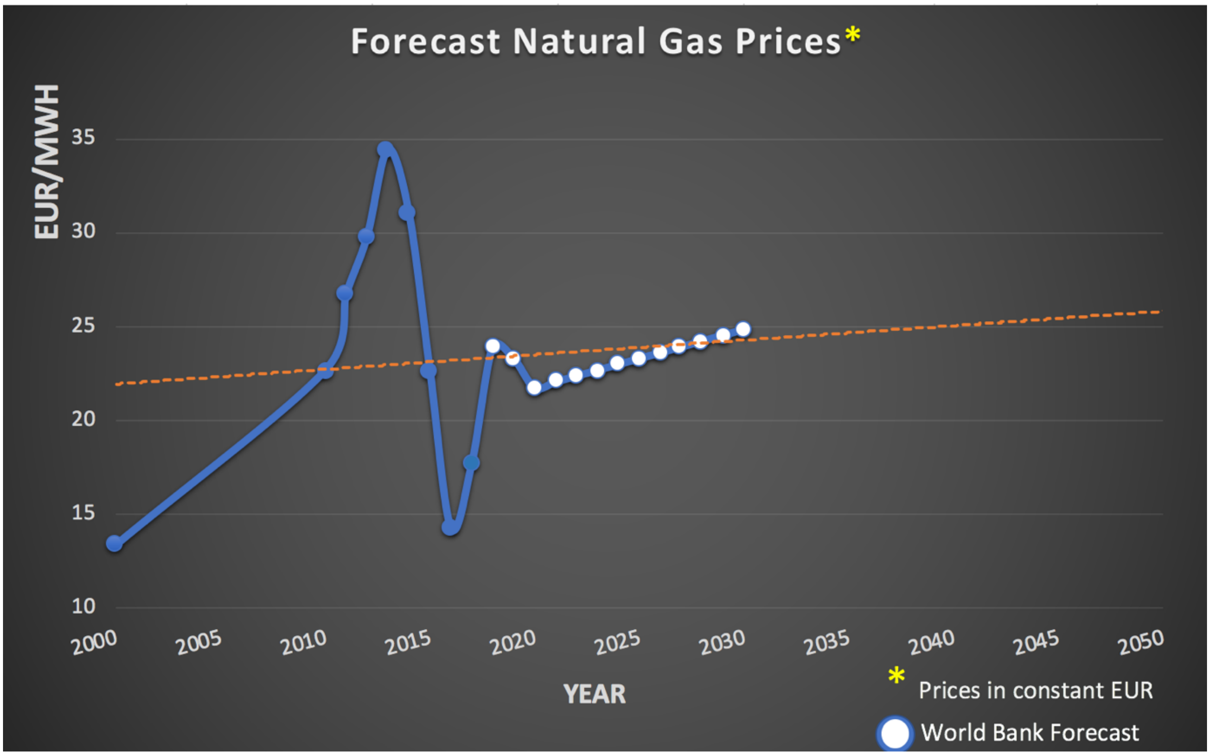


*Figure 42 Forecast Natural Gas Prices*

When using these prices to calculate the NPV an exchange rate of 0,11 $\frac{€/\mathrm{MWh}}{\mathrm{NOK/Sm3}}$ where used, In addition to this, 0,1 NOK/ Sm$^3$ will be removed from the price for transportation costs.[17, 70] When conducting the sensitivity analysis the three prices will be used in the low, average and high estimates. Every scenario will assume a constant price and that the platform will use the same amount of natural gas each year, resulting in the same amount of "saved money" each year. Obtaining the conclusive price of 2,1 NOK/Sm$^3$, 2,6 NOK/ Sm$^3$, and 3 NOK/ Sm$^3$ for the cases respectively.

### 6.3.2 Operational costs and savings

Table 10 and 11 lists the different annual operational costs and savings the NPV analysis uses. For the PEM fuel cell and alkaline electrolyser Shell did not list any OpEx. The usual estimate is 2-5% of CapEx, as OpEx for fuel cells and electrolysers when onshore.[71] Since the project would be offshore, it is reasonable to assume that the OpEx would be higher. Therefore, the OpEx will be set at 5% of CapEx. The same estimate was used for the ammonia ICE because industry had no estimates regarding this. The windfarm OpEx is the same as Multiconsult used when calculating Hywind Tampen[17]. For the H-B system, it was used estimates given in a study.[72] For the OpEx of subsea ammonia storage it was given an estimate of 5 million by NOV, but it's important to emphasize that this is just an estimation and not a number NOV have tested and verified. There was not any estimate by Umoe on OpEx for subsea storage of hydrogen, therefore it was estimated at the same price as for subsea ammonia storage. Since ammonia would use an ICE for power generation it is assumed that it will emit as much $NO_x$ as the original gas turbine, resulting in no saved cost on $NO_x$ emissions. Realistically it is assumed that most of the $NO_x$ will be removed, but given the uncertainty of this, these terms are made.

*Table 10 Operational Cost*

| **Operational Cost** | **2020 Hydrogen FC** | **2020 Ammonia ICE** | **2030 Hydrogen FC** | **2030 Ammonia ICE** |
|---|---|---|---|---|
| Alkaline Electrolyzer | NOK 52 250 000 | NOK 52 250 000 | NOK 27 550 000 | NOK 27 550 000 |
| Ammonia Production; H-B | - | NOK 66 354 840 | - | NOK 66 354 840 |
| Ammonia Combustion Engine | - | NOK 10 450 000 | - | NOK 10 450 000 |
| PEM Fuel Cell | NOK 62 500 000 | - | NOK 37 500 000 | - |
| Salt Water Reverse Osmosis | NOK 748 980 | NOK 972 925 | NOK 748 980 | NOK 972 925 |
| Subsea Storage Ammonia | - | NOK 5 000 000 | - | NOK 5 000 000 |
| Subsea Storage Hydrogen | NOK 5 000 000 | - | NOK 5 000 000 | - |
| Windfarm | NOK 153 000 000 | NOK 198 000 000 | NOK 119 000 000 | NOK 154 000 000 |
| ***Total Yearly Operational Cost (Year 1)*** | NOK 273 498 980 | NOK 333 027 765 | NOK 189 798 980 | NOK 264 327 765 |

*Table 11 Operational Savings*

| **Operational Savings** | **2020 Hydrogen FC** | **2020 Ammonia ICE** | **2030 Hydrogen FC** | **2030 Ammonia ICE** |
|---|---|---|---|---|
| Emissions, CO2-fee | NOK 167 171 417 | NOK 167 171 417 | NOK 295 764 816 | NOK 295 764 816 |
| Emissions, $NO_x$-fee | NOK 22 300 000 | - | NOK 22 300 000 | - |
| Natural Gas | NOK 294 834 951 | NOK 294 834 951 | NOK 294 834 951 | NOK 294 834 951 |
| ***Total Yearly Operational Savings (Year 1)*** | NOK 484 306 369 | NOK 462 006 369 | NOK 612 899 767 | NOK 590 599 767 |

### 6.3.3 Discount rate

The discount rate is used to discount future cash flows for potential projects and estimate their Net Present Value (NPV). The usage of the discount rate is paramount to calculate the NPV. As a project prolongs, the discount rate increases in importance. This is due to the future cash flow being worth less than at the present day. The cost of capital is determined by various factors such as risk, industry and whether the idea competes with other projects.[17]

In the petroleum sector projects normally use a discount rate of 7%.[17] The Norwegian environment agency usually applies a discount rate of 4% for its socio-economic calculations.[17] Furthermore, "Methodology guide techno-economic assessment" writes, "*In typical techno-economic project assessment the discount rate should be set at least two percent above the interest rate of a bank loan.*" [73] Therefore, when calculating the NPV the analysis will use both 4% and 7% discount rates.

## 6.4 Net Present Value

Net Present Value is one of the fundamental terms in investment theory. It calculates the value today, of a future amount. For in and out payment to be comparable at different times, all amounts must be converted to the present value. To convert future value to the present value is called discounting. The NPV analysis looks at a couple of different scenarios. First, it will study the hydrogen FC 2020 and 2030 scenario, and second the ammonia ICE 2020 and 2030 scenario. As mentioned in the lifetime expectancy chapter it will be assumed a lifetime of 20 years for the different components except for electrolyser and fuel cell stack, which is changed every 7 years. The result of the NPV analysis are shown in figure 43 and 44.

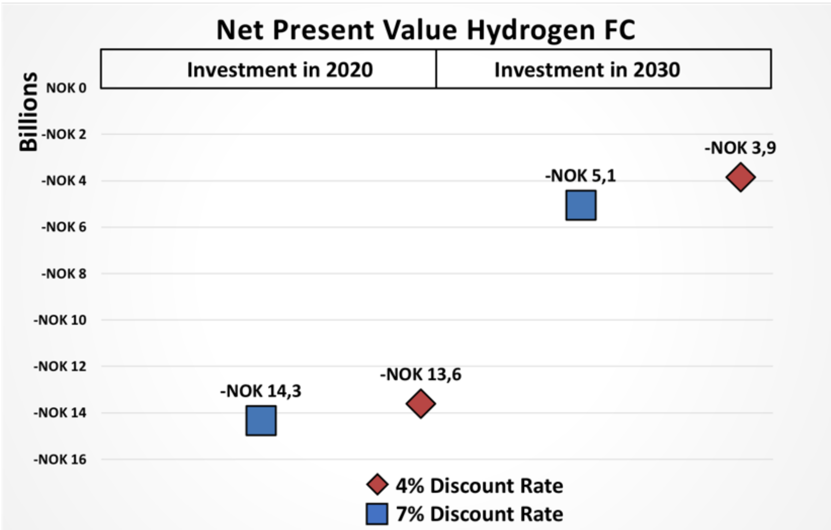


*Figure 43 Net Present Value Hydrogen FC*

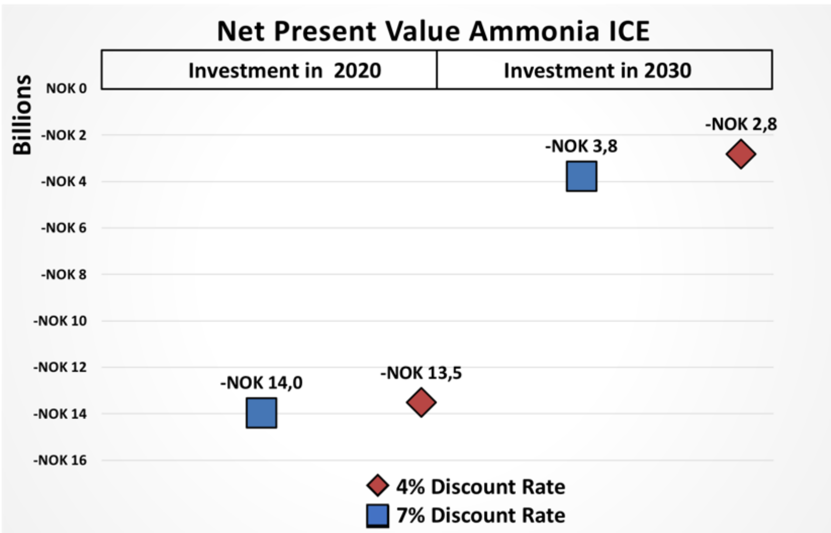


*Figure 44 Net Present Value Ammonia FC*

## 6.5 Sensitivity analysis

Sensitivity analyses will be conducted to obtain a greater understanding of the uncertainties in the techno-economic analyses. First, to understand the uncertainties of the price estimates in the investment cost, low and high estimates are included. These estimates are based on different intervals in the pricing of the components. If there is no interval, the price is set to the price used in table 9. Furthermore, if there is no estimate for cost reduction for the high and low estimate, the cost reduction towards 2030 is estimated at 5% and 15% respectively. This results in figure 45.

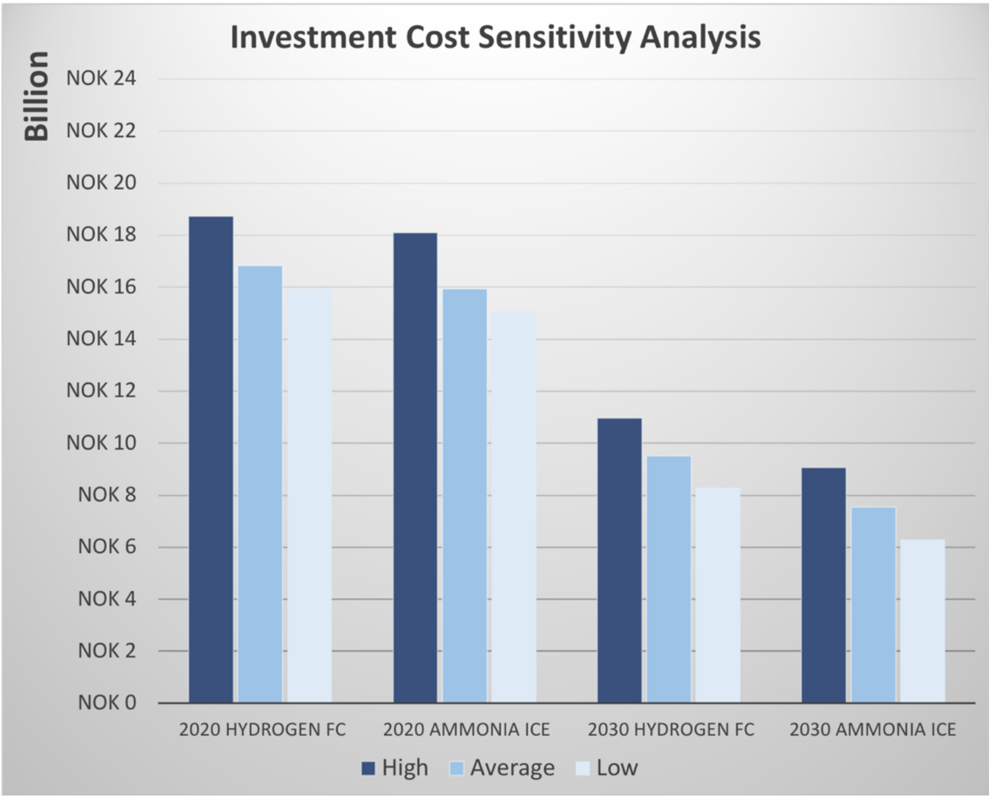


*Figure 45 Investment Cost Sensitivity Analysis*

Furthermore, it is made NPV analyses of low, average and high scenarios for hydrogen FC and ammonia ICE, with both investment decisions in 2020 and 2030. The same conditions are used as for figure 43 and 44, with an assumed lifetime of 20 years for the different components except for electrolyser and fuel cell stack, which changes every 7 years. The result is shown in figure 46 and 47.

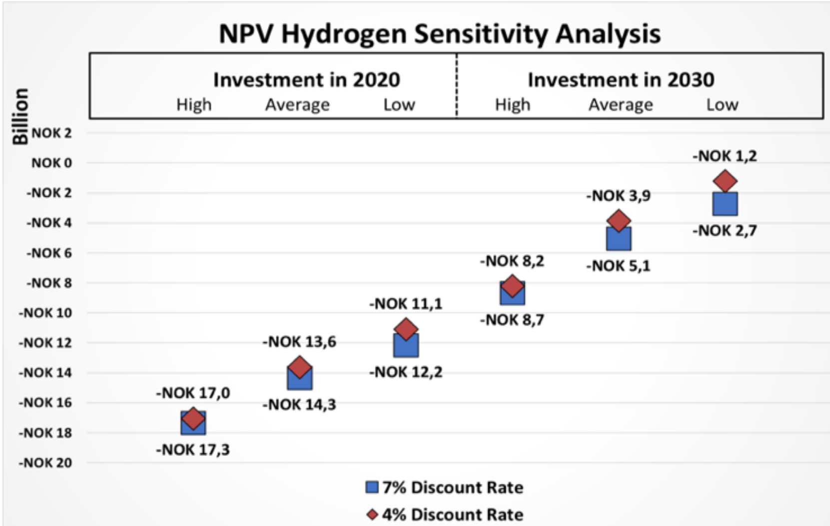


*Figure 46 NPV Hydrogen Sensitivity Analysis*

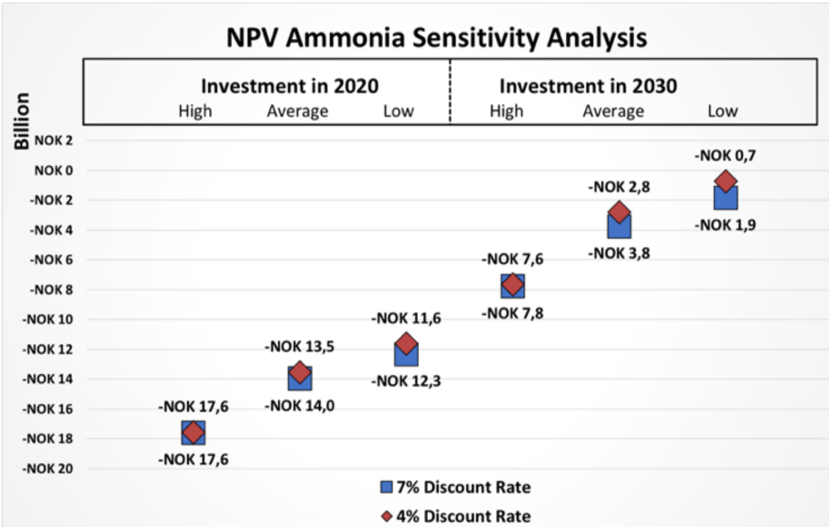


*Figure 47 NPV Ammonia Sensitivity Analysis*

To investigate the effects the life expectancy of the project has on the NPV, a version with 30-year life expectancy is made. This assumption is not unrealistic as Mckinsey said that "*new sites project an operational lifetime of 30 years*".[74] When making this analysis the electrolysers, fuel cells, and ICE systems will be changed in year 20, and the stacks every 7 years. For the remaining components, it is assumed that they will endure throughout the 30 years, which Umoe assumes. [30] The results is shown in figure 48 and 49.

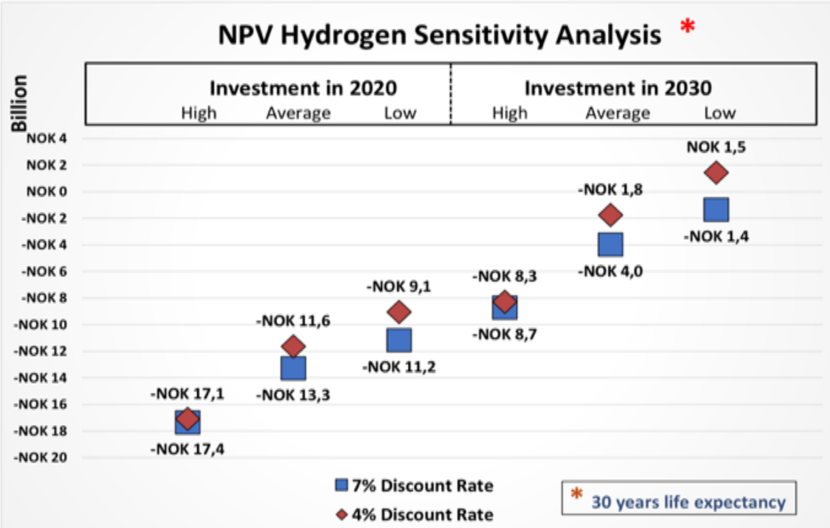


*Figure 49 NPV Hydrogen Sensitivity Analysis **

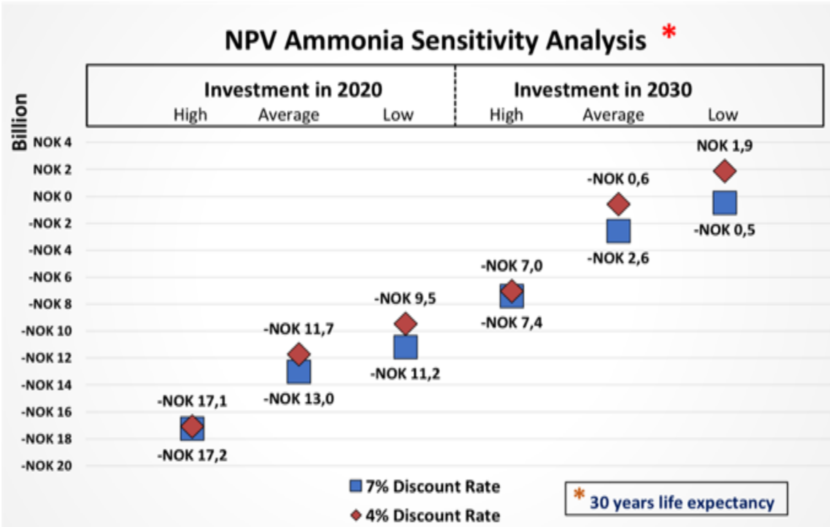


*Figure 48 NPV Ammonia Sensitivity Analysis **

To summarize the NPV, figure 50 and 51 were made. They show the worst and best estimate, and the best case is with a 4% discount rate with a low estimate, and the worst case is a high estimate with a 7% discount rate. The graph showcases quite clear the huge uncertainty in the numbers, as the NPV could differ with several billion NOK.

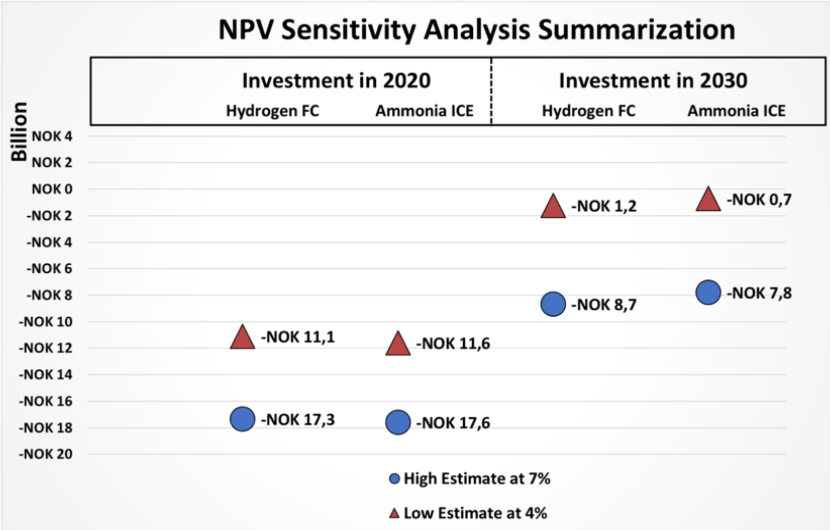


*Figure 51 NPV Sensitivity Analysis Summarization*

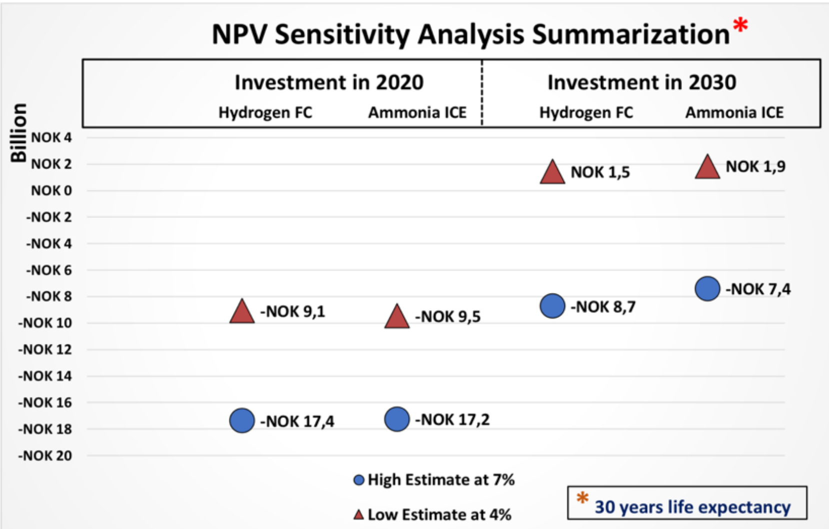


*Figure 50 NPV Sensitivity Analysis Summarization **

## 6.6 Assessment of the project's not priced effects

In the previous section, there have been discussed various segments of the economics for total electrification of an oil platform. What this techno-economic analysis does not take into account, is the future financial benefit for the society, regarding technology improvement and knowledge sharing within similar future projects. Both the wind farm and electrolyser plant are a significant upscaling from previous projects. This implies that although the project is not profitable today, it would most likely help with scale benefits for future projects.

Regardless of when an eventual investment decision for this scenario is, a future project would most likely be for learning and cost reduction regarding fuel cells, electrolysers, subsea storage and floating wind turbines. It is deemed as unlikely that projects like this is profitable in the short term. This project would probably have a learning curve, which would help with a cost reduction of future projects as ZEEDS and Deep Purple. Furthermore, a similar project could have repercussions towards future projects.

Another "not priced effect" is the learning rate. The historical learning rate for wind turbines and associated technology for onshore wind power has been around 18 percent. This indicates that for each doubling of capacity, costs have dropped by 18 percent. For floating wind, Crown Estate Scotland and Catapult assume a learning rate of 13 percent. When Hywind Tampen is completed it will be approximately 118 MW floating wind turbines in the world.[17] For a hydrogen FC system with a 170 MW wind farm, the capacity would rise with around 145%. For an ammonia ICE system with a 220 MW wind farm, the capacity would rise with roughly 190%. This results in nearly 20% and 25% cost reduction respectively for the floating wind sector.

# 7 Discussion

Throughout this thesis several different analyses have been conducted, both related to the technical part and the economical part of the project. Firstly, the necessary size of the windfarm and the required capacity of the energy storage were calculated. During this process, several different ways of producing, storing and utilizing both hydrogen and ammonia have been researched. As mentioned, a lack of time and resources led to the project being narrowed down to two different solutions, one using hydrogen and one using ammonia. The hydrogen system consists of hydrogen stored subsea at 350 Bar and fuel cells to generate power. The ammonia system on the other hand consists of ammonia stored subsea and an ICE paired with generators to produce power. These systems where chosen based on the information supplied in the background chapter and calculations made. On the subject of hydrogen storage, high compression tanks at 350 Bar was chosen over liquid storage, metal hydrides and higher compression storage due to lower prices and higher efficiency. In addition to this the subsea storage provided by Umoe was the only reliable source obtained on subsea storage, and it is still uncertain if the other storage options would be applicable to subsea use. It is important to note that the storage solution provided by Umoe requires 30,000 tanks to store the necessary amount of hydrogen. This high quantity of tanks is assumed to be unrealistic to install. It is therefore assumed that further development is needed to create larger tanks. The solution for ammonia storage was chosen to be NOV´s proposed system. This is also due to this being regarded as the most reliable source on the subject and the most realistic alternative. When deciding the system for electricity generation, PEM fuel cells and ICE were chosen for hydrogen and ammonia respectively. These two alternatives were regarded as the most realistic alternatives short term, with PEM fuel cells as the most efficient.

The techno-economic analyses show that the wind farm and the storage solutions are the largest cost drivers for hydrogen while the wind farm and the electrolysers are the largest cost drivers for ammonia. Storage tanks for hydrogen are estimated to be around 10 times more expensive than ammonia in this project. It is assumed that with further development of hydrogen storage and increased scale this difference will be reduced. The research also showed that the hydrogen system requires 170 MW of wind turbines to produce enough hydrogen to be self-supplied with green energy while the ammonia system requires 220 MW of wind turbines. This is a result of a lower total efficiency for the ammonia system compared to the hydrogen system. The difference in efficiency mainly comes from having to create hydrogen in a H-B process and the fact that the ammonia ICE has a significantly lower efficiency than hydrogen FC. Further the economic analyses show that the ammonia system is assumed to have a lower investment cost both in 2020 and 2030 with the difference being 1 and 2 billion respectively. This further leads to the NPV which have the potential to be positive for both hydrogen and ammonia in 2030, given a 30-year life expectancy, with ammonia assumed to be the most likely. Interestingly the NPV show that in 2020 the hydrogen system has a higher NPV. However, while the wind farm and the electrolysers, which are the two largest cost drivers for ammonia, are expected to have a significant decrease in cost until 2030, this is not the case for hydrogen storage. Due to an uncertainty in the reduction of prices of hydrogen storage the price reduction was estimated to be 5-15%.

While extensive research has been conducted to determine the numbers, which are the baseline of this thesis, several numbers have been estimated due to a lack of sources. Electrification of platforms using wind power and hydrogen, or ammonia have never before been done, which leads to a lack of reliable sources. In addition to this, the sources used are often estimates made by companies and are not tested and verified. It is expected that with continued research and development the prices of all components will drop until 2030. In addition to this both hydrogen and ammonia are applicable to several uses such as ships, cars and planes. This increase in scale are also expected to reduce cost, but it is uncertain if the cost reduction used in this thesis is realistic. Furthermore, there are also uncertainties regarding the wind power in this thesis. As previously explained this project utilizes 10 MW turbines. Given that a project of this size is expected to be several years ahead in time it is reasonable to assume that the turbines used would be significantly larger, and most likely above 15 MW. This increase in size is expected to reduce cost significantly as well as increasing the capacity factor for each turbine. A net capacity factor of 38% were measured for this thesis and is considered as low. The low capacity factor can originate from low efficiency from the turbines as well as the location for the wind measurements being ill-suited for a wind farm due to low wind speeds. An increase in capacity factor would reduce the number of wind turbines needed for a project like this, which would further lead to a reduction in cost. The platform in this thesis is as explained a hypothetical platform with a constant power demand of 40 MW. This power demand was used due to a lack of information regarding power usage on platforms. It is not perceived as realistic that the power demand for a 40 MW platform would stay consistently at 40 MW. It is further assumed that more accurate data on power usage would lead to a total annual electricity demand being lower than in this thesis. This would lead to a lower capacity needed for both the wind farm and the energy storage which would further reduce cost.

When examining a project like this there are factors beyond just the economical part that needs to be assessed. As explained at the start of the thesis, Norwegian oil and gas platforms are the second largest source of climate gas emissions in Norway and constitutes 27% of the total climate gas emissions. This means that if systems like the ones in this thesis where implemented, more than 1/4 of the Norwegian climate gas emissions could be removed. This would make Norway the frontrunners in the world at this subject. Further, projects like this would create jobs and socio-economic advancements. In the techno economical part of this thesis, subsidies were not included in the equation, but it is reasonable to assume that projects like this would get subsidies, which could make the economics more lucrative. An example is the Hywind Tampen project which is mostly covered by subsidies. As explained previously it is estimated that the hydrogen and ammonia tanks will have 700 and 5000 tonnes left in the tanks, respectively, at the end of year one. This excess hydrogen and ammonia can potentially be sold to increase the NPV. Although this is uncertain and is not researched further in this thesis, this can potentially speed up the development of hydrogen and ammonia use in transport.

# 8 Conclusion

During this thesis, the necessary capacity of both hydrogen and ammonia backup systems have been calculated, together with the necessary capacity of the windfarm needed for powering a 40 MW platform. Research indicated that it was necessary with 170 and 220 MW of wind turbines for the hydrogen and ammonia systems respectively. In addition to this, a hydrogen tank capacity of around 1200 tons and an ammonia tank capacity of around 9500 tons was calculated. In the techno-economic analysis it was calculated a total investment cost in 2020 of NOK 16.8 billion for the hydrogen system. and NOK 15.9 billion for the ammonia system. Furthermore, these costs are expected to drop to NOK 9.5 billion, and NOK 7.5 billion for the hydrogen and ammonia respectively in 2030. These investment costs were then used as part of the NPV, which showed potential for both solutions to be profitable in 2030 given a 30-year life expectancy. It is further accepted that none of the solutions would have a positive NPV if investment is set to 2020. The techno-economic analysis also showed that the main cost driver for both systems are the wind farm which constitutes 61% of the hydrogen and 83% of the ammonia investment costs in 2020. Moreover, the subsea storage was found to be the second largest cost driver for hydrogen and constitutes 23% of the investment costs in 2020. It is worth to mention that the cost of the subsea hydrogen storage was assumed to drop by 10% towards 2030 but with increased scale and continued R&D this can most likely be increased. The research also demonstrated the implications of increasing the life expectancy of the wind farm from 20 to 30 years, which led to the NPV increasing, in most cases by several billion NOK.

This thesis discusses the problems regarding the energy demand of the platform. The fact that no data shows the hourly power demand similarly to the hourly production from the wind farm. leads to calculations being inaccurate. Given more time and resources it would be beneficial to gather this information and get more detailed calculations. In addition, wind data from other locations should be compared to those used in this thesis. A more suited location for the wind farm could provide a higher capacity factor which, as discussed, would reduce cost.

Taking all aspects of this thesis into consideration, it is uncertain if it would be economically profitable. However, the socio-economic advantages are not to be discarded. Projects like this could drastically decrease Norway's climate footprint and pave the way for future zero emission projects.

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# 10 List of tables

# 11 List of figures

# 12 Attachments

Appendix 1; Table used for Carbon Price forecast

| Year | High | Average | Low |
|---|---|---|---|
| 2020 | 650 | 650 | 850 |
| 2021 | 662,5 | 700 | 900 |
| 2022 | 675 | 750 | 950 |
| 2023 | 687,5 | 800 | 1000 |
| 2024 | 700 | 850 | 1050 |
| 2025 | 712,5 | 900 | 1100 |
| 2026 | 725 | 950 | 1150 |
| 2027 | 737,5 | 1000 | 1200 |
| 2028 | 750 | 1050 | 1250 |
| 2029 | 762,5 | 1100 | 1300 |
| 2030 | 775 | 1150 | 1350 |
| 2031 | 787,5 | 1200 | 1400 |
| 2032 | 800 | 1250 | 1450 |
| 2033 | 812,5 | 1300 | 1500 |
| 2034 | 825 | 1350 | 1550 |
| 2035 | 837,5 | 1400 | 1600 |
| 2036 | 850 | 1450 | 1650 |
| 2037 | 862,5 | 1500 | 1700 |
| 2038 | 875 | 1550 | 1750 |
| 2039 | 887,5 | 1600 | 1800 |
| 2040 | 900 | 1650 | 1850 |
| 2041 | 912,5 | 1700 | 1900 |
| 2042 | 925 | 1750 | 1950 |
| 2043 | 937,5 | 1800 | 2000 |
| 2044 | 950 | 1850 | 2050 |
| 2045 | 962,5 | 1900 | 2100 |
| 2046 | 975 | 1950 | 2150 |
| 2047 | 987,5 | 2000 | 2200 |
| 2048 | 1000 | 2050 | 2250 |
| 2049 | 1012,5 | 2100 | 2300 |
| 2050 | 1025 | 2150 | 2350 |

Appendix 2; Natural gas price forecast¨

| Year | USD/MMBTU | EUR/MWh |
|---|---|---|
| **2000** | 4,3 | 13,33 |
| **2010** | 7,3 | 22,63 |
| **2011** | 8,6 | 26,66 |
| **2012** | 9,6 | 29,76 |
| **2013** | 11,1 | 34,41 |
| **2014** | 10 | 31 |
| **2015** | 7,3 | 22,63 |
| **2016** | 4,6 | 14,26 |
| **2017** | 5,7 | 17,67 |
| **2018** | 7,7 | 23,87 |
| **2019** | 7,5 | 23,25 |
| **2020** | 7 | 21,7 |
| **2021** | 7,1 | 22,01 |
| **2022** | 7,2 | 22,32 |
| **2023** | 7,3 | 22,63 |
| **2024** | 7,4 | 22,94 |
| **2025** | 7,5 | 23,25 |
| **2026** | 7,6 | 23,56 |
| **2027** | 7,7 | 23,87 |
| **2028** | 7,8 | 24,18 |
| **2029** | 7,9 | 24,49 |
| **2030** | 8 | 24,8 |

Historical gas prices was collected from statista [75] and future estimates was collected from World bank[69]. World bank had no estimates for 2026-2029, so a linear increase from 7,5 to 8 were implanted.

Appendix 3:
This is the numbers used to calculate the NPV and investment cost for the scenario. These tables do not show the different intervals used for the sensitivity analysis.

| Part | Volume | Comment |
|---|---|---|
| Alkaline Electrolyzer 2020 CapEx [kr/kW] | 11 000 | [23] |
| Alkaline Electrolyzer 2020 OpEx [kr/kW] | 550 | 5%  of capex |
| Alkaline Electrolyzer 2030 CapEx [kr/kW] | 5 800 | [76] |
| Alkaline Electrolyzer 2030 OpEx [kr/kW] | 290 | 5,% of capex |
| Ammonia Combustion Engine [kr/kw] | 5 225 | [55] |
| Ammonia combustion Engine OpEx [kr/kw] | 261,25 | 5% of Capex |
| Ammonia Production Haber-bosch (545 mt/day) CapEx [kr/mt] | 485 | [59] |
| Ammonia Production Haber-bosch (545 mt/day) OpEx [kr/mt] | 342 | [59] |
| PEM Fuel Cell 2020 CapEx [kr/kW] | 25 000 | [77] |
| PEM Fuel Cell 2020 OpEx [kr/kW] | 1 250 | 5% av capex et (estimat) |
| PEM Fuel Cell 2030 CapEx [kr/kW] | 15 000 | [77] |
| PEM Fuel Cell 2030 OpEx [kr/kW] | 750 | 2-5% |
| Stack Replacement Capex [kr/kw] replacement | 2100 | [62] |

| Part | Volume | Comment |
|---|---|---|
| Salt Water Reverse Osmosis CapEx [kr/MLD] | 14 250 000 | [78] |
| Salt Water Reverse Osmosis OpEx [kr/m3] | 5 | [78] |
| Daily Consumption Seawater Hydrogen [L] | 432 000 | |
| Daily Consumption Seawater Ammonia [L] | 561 168 | |

| Part | Volume | Comment |
|---|---|---|
| Electrolyser capasity Hydrogen [MW] | 95 | |
| Electrolyser  capasity Ammonia [MW] | 124 | |
| Load Factor Fuel Cell | 0,8 | |
| Load Factor Ammonia ICE $*\eta_{generator} *\eta_{inverter}$ | 0,78 | |
| Platform Power Requierment [kW] | 40 000 | |
| Offshore Platform [USD/Mwelektrolyse] | 180000 | [79] Personal communication |

| Part | Volume | Comment |
|---|---|---|
| Emission CO2-fee [kr/tonn] 2020 | 650 | Appendix1 |
| Emission Co2-fee [kr/tonn] 2030 | 1 150 | Appendix1 |
| Emission Nox-fee [kr/kg] | 22 | [68] |
| Emissions CO2 [Tonnes/TJ] | 57 | [80] |
| Emissions Tonnes (Natural Gas) [Tonnes Co2/year] | 257 187 | Appendix 4 |
| Emissions Tonnes (Natural Gas)[Tonnnes NOx/year] | 1 000 | |

| Part | Volume | Comment |
|---|---|---|
| Exchange Euro [kr/€] | 10 | [81] |
| Exchange US Dollar [kr/$] | 9,5 | [82] |
| Exchange Natural gas prices [(€/MWh)/(NOK/Sm3)] | 0,11 | [70] |

| Part | Volume | Comment |
|---|---|---|
| Natural Gas Price [nok/Sm3] | 2,7 | Appendix 2 |
| Natural Gas Transportation Price [kr/Sm3] | 0,1 | [17] |
| Natural Gas Volume [Sm3] | 113 398 058 | Appendix 4 |

| Part | Volume | Comment |
|---|---|---|
| Subsea Storage Cost Hydrogen [kr/kg h2] | 3 250 | [30] |
| Subsea Storage Cost Ammonia [kr/kg NH3] | 47 | [9] |
| Storage Volume Ammonia [kg] | 9 500 000 | Chapter 4 |
| Storage Volume Hydrogen [kg] | 1 200 000 | Chapter 4 |
| Subsea Storage OpEx [kr] | 5000000 | [9] |

| Part | Volmue | Comment |
|---|---|---|
| Removal of windfarm kr/MW | 10000000 | [17] |
| Windfarm [kW] (hydrogen) | 170 000 | |
| Windfarm [kW] (Ammonia) | 220 000 | |
| Windfarm 2020 CapEx [kr/MW] | 60 000 000 | [17] |
| Windfarm 2020 OpEx [kr/MW] | 900 000 | [17] |
| Windfarm 2030 CapEx [kr/MW] | 26 000 000 | [17] |
| Windfarm 2030 OpEx [kr/MW] | 700 000 | [17] |

Appendix 4

This is the numbers for natural gas assuming a consumption for a constant 40 MW platform, running on a gas turbine, assuming 24/7 power demand for a year.

| Medium | Weigt [kg] | Volume [m3] | Volume [Sm3] | Efficiency | Densety [kg/m3] | kWh/kg | kWh/sm3 | MJ/Sm3 | Tonn CO2/Tj | Tonn CO2 |
|---|---|---|---|---|---|---|---|---|---|---|
| Natural Gas | 85 882 353 | 343 529 | 113 398 058 | 0,3 | 250 | 13,6 | 10,3 | 40 | 56,7 | 257 187 |

Appendix 5; This is an example of how the NVP analysis were made. It has been conducted 50 different types of this analysis.

| Economic analysis 2020 7% | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Cost of capital | 7,00 % | | | | | | | | | | | |
| Initial Cost of Project | kr 16 824 856 000 | | | | | | | | | | | |
| **Cash Inflows** | **Start Year 2020** | | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 |
| Savings CO2-fee | | | kr 167 171 417 | kr 180 030 757 | kr 192 890 097 | kr 205 749 437 | kr 218 608 777 | kr 231 468 117 | kr 244 327 456 | kr 257 186 796 | kr 270 046 136 | kr 282 905 476 |
| Savings Nox-fee | | | kr 22 300 000 | kr 22 300 000 | kr 22 300 000 | kr 22 300 000 | kr 22 300 000 | kr 22 300 000 | kr 22 300 000 | kr 22 300 000 | kr 22 300 000 | kr 22 300 000 |
| Savings Natural Gas | | | kr 294 834 951 | kr 294 834 951 | kr 294 834 951 | kr 294 834 951 | kr 294 834 951 | kr 294 834 951 | kr 294 834 951 | kr 294 834 951 | kr 294 834 951 | kr 294 834 951 |
| **Cash Inflow** | | | **kr 484 306 369** | **kr 497 165 709** | **kr 510 025 049** | **kr 522 884 388** | **kr 535 743 728** | **kr 548 603 068** | **kr 561 462 408** | **kr 574 321 748** | **kr 587 181 087** | **kr 600 040 427** |
| **PV of Cash inflow** | | | kr 452 622 775 | kr 434 243 784 | kr 416 332 364 | kr 398 905 996 | kr 381 977 874 | kr 365 557 388 | kr 349 650 570 | kr 334 260 486 | kr 319 387 606 | kr 305 030 126 |
| Cumulative Cash Inflow | | | **kr 452 622 775** | **kr 886 866 559** | **kr 1 303 198 923** | **kr 1 702 104 920** | **kr 2 084 082 794** | **kr 2 449 640 182** | **kr 2 799 290 751** | **kr 3 133 551 237** | **kr 3 452 938 844** | **kr 3 757 968 970** |
| **Costs** | | | | | | | | | | | | |
| Initial Investment | | kr 16 824 856 000 | | | | | | | | | | |
| New Electrolyzer and fuel cell stack | | | | | | | | | kr 210 000 000 | | | |
| Removal of windfarm | | | | | | | | | | | | |
| Windfarm | | | kr 198 000 000 | kr 198 000 000 | kr 198 000 000 | kr 198 000 000 | kr 198 000 000 | kr 198 000 000 | kr 198 000 000 | kr 198 000 000 | kr 198 000 000 | kr 154 000 000 |
| PEM Fuel Cell | | | kr 62 500 000 | kr 62 500 000 | kr 62 500 000 | kr 62 500 000 | kr 62 500 000 | kr 62 500 000 | kr 62 500 000 | kr 62 500 000 | kr 62 500 000 | kr 37 500 000 |
| Alkiline Electrolyzer | | | kr 52 250 000 | kr 52 250 000 | kr 52 250 000 | kr 52 250 000 | kr 52 250 000 | kr 52 250 000 | kr 52 250 000 | kr 52 250 000 | kr 52 250 000 | kr 27 550 000 |
| Salt Water Reverse Osmosis and Subsea Storage | | | kr 5 748 980 | kr 5 748 980 | kr 5 748 980 | kr 5 748 980 | kr 5 748 980 | kr 5 748 980 | kr 5 748 980 | kr 5 748 980 | kr 5 748 980 | kr 5 748 980 |
| **Cash Outflow** | | | kr 318 498 980 | kr 318 498 980 | kr 318 498 980 | kr 318 498 980 | kr 318 498 980 | kr 318 498 980 | kr 528 498 980 | kr 318 498 980 | kr 318 498 980 | kr 224 798 980 |
| **PV of Cash Outflow** | | kr 16 824 856 000 | kr 297 662 598 | kr 278 189 344 | kr 259 990 041 | kr 242 981 347 | kr 227 085 371 | kr 212 229 319 | kr 329 122 603 | kr 185 369 306 | kr 173 242 342 | kr 114 276 402 |
| Cumulative Cash Outflow | | **kr 16 824 856 000** | **kr 17 122 518 598** | **kr 17 400 707 942** | **kr 17 660 697 983** | **kr 17 903 679 330** | **kr 18 130 764 701** | **kr 18 342 994 020** | **kr 18 672 116 623** | **kr 18 857 485 929** | **kr 19 030 728 272** | **kr 19 145 004 674** |
| | Manual | NPV Fx | | | | | | | | | | |
| NPV of Project | **-kr 14 340 924 319** | **-kr 14 340 924 319** | | | | | | | | | | |
| IRR | **-11,73 %** | | | | | | | | | | | |
| ROI | **-70,06 %** | | | | | | | | | | | |
| **Helper cells for functions:** | | | | | | | | | | | | |
| Cash flow | | -kr 16 824 856 000 | kr 165 807 389 | kr 178 666 729 | kr 191 526 069 | kr 204 385 408 | kr 217 244 748 | kr 230 104 088 | kr 32 963 428 | kr 255 822 768 | kr 268 682 107 | kr 375 241 447 |
| | | | 1 | 2 | 3 | 4 | 5 | 6 | 7 | 8 | 9 | 10 |
| **Break even analysis** | | | | | | | | | | | | |
| PV of cash flow | | -kr 16 824 856 000 | kr 154 960 177 | kr 156 054 440 | kr 156 342 323 | kr 155 924 649 | kr 154 892 503 | kr 153 328 070 | kr 20 527 966 | kr 148 891 180 | kr 146 145 264 | kr 190 753 724 |
| Total cash flow | | -kr 16 824 856 000 | -kr 16 669 895 823 | -kr 16 513 841 383 | -kr 16 357 499 060 | -kr 16 201 574 411 | -kr 16 046 681 908 | -kr 15 893 353 838 | -kr 15 872 825 872 | -kr 15 723 934 692 | -kr 15 577 789 428 | -kr 15 387 035 704 |

| | 11 | 12 | 13 | 14 | 15 | 16 | 17 | 18 | 19 | 20 |
|---|---|---|---|---|---|---|---|---|---|---|
| Savings CO2-fee | kr 295 764 816 | kr 308 624 155 | kr 321 483 495 | kr 334 342 835 | kr 347 202 175 | kr 360 061 515 | kr 372 920 854 | kr 385 780 194 | kr 398 639 534 | kr 411 498 874 |
| Savings Nox-fee | kr 22 300 000 | kr 22 300 000 | kr 22 300 000 | kr 22 300 000 | kr 22 300 000 | kr 22 300 000 | kr 22 300 000 | kr 22 300 000 | kr 22 300 000 | kr 22 300 000 |
| Savings Natural Gas | kr 294 834 951 | kr 294 834 951 | kr 294 834 951 | kr 294 834 951 | kr 294 834 951 | kr 294 834 951 | kr 294 834 951 | kr 294 834 951 | kr 294 834 951 | kr 294 834 951 |
| **Cash Inflow** | **kr 612 899 767** | **kr 625 759 107** | **kr 638 618 447** | **kr 651 477 786** | **kr 664 337 126** | **kr 677 196 466** | **kr 690 055 806** | **kr 702 915 146** | **kr 715 774 485** | **kr 728 633 825** |
| **PV of Cash inflow** | kr 291 184 264 | kr 277 844 527 | kr 265 003 951 | kr 252 654 318 | kr 240 786 347 | kr 229 389 873 | kr 218 453 996 | kr 207 967 228 | kr 197 917 610 | kr 188 292 827 |
| Cumulative Cash Inflow | **kr 4 049 153 235** | **kr 4 326 997 762** | **kr 4 592 001 713** | **kr 4 844 656 030** | **kr 5 085 442 377** | **kr 5 314 832 250** | **kr 5 533 286 246** | **kr 5 741 253 474** | **kr 5 939 171 084** | **kr 6 127 463 910** |
| New Electrolyzer and fuel cell stack | | | | kr 210 000 000 | | | | | | |
| Removal of windfarm | | | | | | | | | | kr 1 700 000 000 |
| Windfarm | kr 154 000 000 | kr 154 000 000 | kr 154 000 000 | kr 154 000 000 | kr 154 000 000 | kr 154 000 000 | kr 154 000 000 | kr 154 000 000 | kr 154 000 000 | kr 154 000 000 |
| PEM Fuel Cell | kr 37 500 000 | kr 37 500 000 | kr 37 500 000 | kr 37 500 000 | kr 37 500 000 | kr 37 500 000 | kr 37 500 000 | kr 37 500 000 | kr 37 500 000 | kr 37 500 000 |
| Alkiline Electrolyzer | kr 27 550 000 | kr 27 550 000 | kr 27 550 000 | kr 27 550 000 | kr 27 550 000 | kr 27 550 000 | kr 27 550 000 | kr 27 550 000 | kr 27 550 000 | kr 27 550 000 |
| Salt Water Reverse Osmosis and Subsea Storage | kr 5 748 980 | kr 5 748 980 | kr 5 748 980 | kr 5 748 980 | kr 5 748 980 | kr 5 748 980 | kr 5 748 980 | kr 5 748 980 | kr 5 748 980 | kr 5 748 980 |
| **Cash Outflow** | kr 224 798 980 | kr 224 798 980 | kr 224 798 980 | kr 434 798 980 | kr 224 798 980 | kr 224 798 980 | kr 224 798 980 | kr 224 798 980 | kr 224 798 980 | kr 1 924 798 980 |
| **PV of Cash Outflow** | kr 106 800 376 | kr 99 813 436 | kr 93 283 585 | kr 168 622 541 | kr 81 477 496 | kr 76 147 192 | kr 71 165 600 | kr 66 509 907 | kr 62 158 791 | kr 497 404 633 |
| Cumulative Cash Outflow | **kr 19 251 805 050** | **kr 19 351 618 485** | **kr 19 444 902 070** | **kr 19 613 524 611** | **kr 19 695 002 106** | **kr 19 771 149 298** | **kr 19 842 314 899** | **kr 19 908 824 805** | **kr 19 970 983 596** | **kr 20 468 388 229** |
| Cash flow | kr 388 100 787 | kr 400 960 127 | kr 413 819 467 | kr 216 678 806 | kr 439 538 146 | kr 452 397 486 | kr 465 256 826 | kr 478 116 166 | kr 490 975 505 | -kr 1 196 165 155 |
| | 11 | 12 | 13 | 14 | 15 | 16 | 17 | 18 | 19 | 20 |
| PV of cash flow | kr 184 383 888 | kr 178 031 091 | kr 171 720 366 | kr 84 031 777 | kr 159 308 852 | kr 153 242 680 | kr 147 288 396 | kr 141 457 321 | kr 135 758 819 | -kr 309 111 806 |
| Total cash flow | -kr 15 202 651 815 | -kr 15 024 620 724 | -kr 14 852 900 357 | -kr 14 768 868 581 | -kr 14 609 559 729 | -kr 14 456 317 048 | -kr 14 309 028 652 | -kr 14 167 571 331 | -kr 14 031 812 513 | -kr 14 340 924 319 |

Appendix 6; overview of the efficiency's to components.

| Part | Efficiency |
|---|---|
| Seawater desalination | 0,99 [52] |
| Electrolysis | 0,7[21] |
| Haber-Bosch | 0,8 [42] |
| Compression | 0,97 |
| **Efficiency ammonia production** | 0,54 |
| | |
| Fuel cell | 0,5 [55] |
| DC/AC grid inverter | 0,95 [53] |
| **Efficiency ammonia usage** | 0,48 |
| | |
| **Total system efficiency** | **25,5%** |
| | |
| **Part** | **Efficiency** |
| Seawater desalination | 0,99[52] |
| Electrolysis | 0,7 [21] |
| Compression | 0,94[29] |
| **Efficiency hydrogen production** | 0,65 |
| | |
| Fuel cell | 0,6 [21] |
| DC/AC inverter | 0,95[53] |
| **Efficiency hydrogen usage** | 0,57 |
| | |
| **Total system efficiency** | 37,1 % |

| Part | Efficiency |
|---|---|
| Seawater desalination | 0,97[52] |
| Electrolysis | 0,7 [21] |
| Compression | 0,91[29] |
| **Efficiency hydrogen production** | 0,62 |
| | |
| Fuel cell | 0,6 [21] |
| DC/AC inverter | 0,95[53] |
| **Efficiency hydrogen usage** | 0,57 |
| | |
| **Total system efficiency** | 35,1 % |

| Part | Efficiency |
|---|---|
| Seawater desalination | 0,99 [52] |
| Electrolysis | 0,7[21] |
| Haber-Bosch | 0,8 [42] |
| Compression | 0,97 |
| **Efficiency ammonia production** | 0,54 |
| | |
| ICE | 0,45 [55] |
| Generator | 0,97 [55] |
| DC/AC grid inverter | 0,95 [53] |
| **Efficiency ammonia usage** | 0,415 |
| | |
| **Total system efficiency** | **22,3%** |