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Optimizing the economic value of offshore wind resources

A bottom-up valuation of an offshore wind farm, coupled with hydrogen production and energy storage

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NORWEGIAN SCHOOL OF ECONOMICS

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Abstract

In this thesis, we analyze a hypothetical offshore wind farm placed off the southwestern coast of Norway. To maximize the economic value, we examine four different scenarios to best use the electricity generated from the wind farm. We have employed a bottom-up approach for revenue and cost inputs to analyze the economic value created from the different scenarios.

We find the offshore wind farm to be a profitable investment without subsidies. Fitting a wind farm with an onshore electrolyzer for a hybrid system switching between hydrogen production and direct electricity sale generates the highest net present value. This option also allows for a higher degree of flexibility in the event of hydrogen or electricity markets experiencing significant shifts in prices.

We find exclusively producing hydrogen to be economically unattractive compared to the sale of electricity at a hydrogen price of \$3.50/kg. We also find that the incremental revenues gained from energy storage do not outweigh capital costs.

Keywords – Offshore wind, Hydrogen, Hydrogen coupling, Grid scale lithium-ion storage, Pumped hydro storage

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1 Introduction

1.1 Introduction

Wind is one of the most promising sources of renewable electricity generation. IEA stated the rise of renewable offshore wind energy as one of the most dominant and crucial shares of their roadmap to a net-zero emission society (IEA, 2021). However, the economic conditions have previously been argued to be unfavorable without governmental subsidies (Buli, 2021). Recently, RWE won a tender to construct and operate an 800-1000MW offshore wind farm in Denmark, with an obligation to pay DKK 2.8bn(Danish Energy Agency, 2021). This development is indicative of future tendering processes as offshore wind must be competitive without subsidies.

The amount of offshore wind in Norway is increasing, with a total capacity of 4.5 GW out for tender in 2020 (NVE, 2021). There are mainly two reasons why offshore wind investment on the Norwegian continental shelf is reasonable. First, the massive areas of suitable offshore wind placement enable significant economies of scale through size and number of farms. Second, the petroleum clusters have developed experience operating facilities in the harsh offshore environment, which could lead to a polished transition to both bottom-fixed and floating offshore wind generation of electricity.

Nevertheless, renewable energy face difficulties in their ability to be stored. Green hydrogen is one potential solution as an energy carrier. Hydrogen could solve the storage issue through chemical storage in ammonia or methanol, or by releasing energy through a fuel cell. Another potential solution is to take advantage of the beneficial geographical typology in Norway through pumped hydro storage. The success of lithium-ion batteries in vehicles has led to a massive amount of R&D to suit the technology for large-scale storage. The volatility in the electricity prices is expected to increase in line with the share of renewable electricity generation. To perform an efficient redistribution of energy to peak hours could potentially increase the profitability of the wind farm.

Through four different scenarios, we intend to investigate the economic viability of an offshore wind farm located off the southwest coast of Norway.

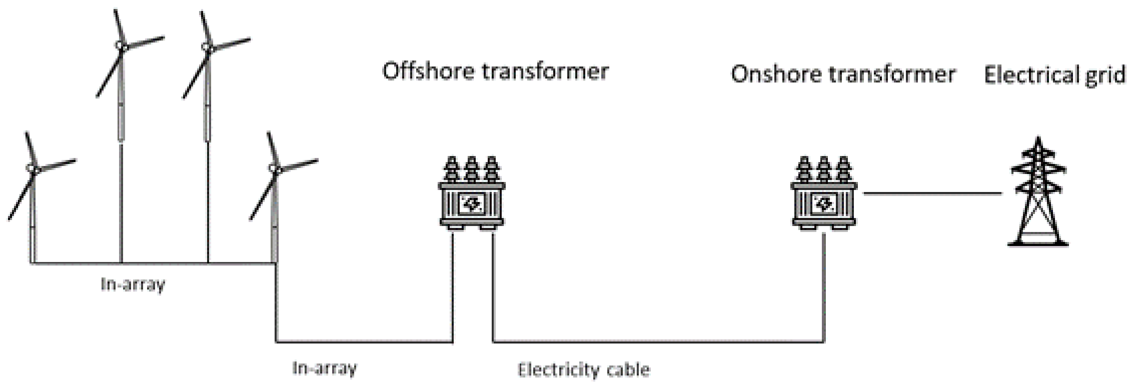
Consequently, we constructed a hypothetical wind farm. The wind farm will consist of

67 Vestas 15MW wind turbines, with a total capacity of approximately 1 GW. By the large capacity and large turbines, we attempt to capture the benefits of economies of scale through two dimensions. The wind farm's location will be 150km from the southwest coast of Norway due to requirements in water depth for the construction of a bottom-fixed offshore wind farm.

1.1.1 Scenario 1

As a baseline for comparison, we analyze an offshore wind farm selling power to the power grid as pictured in Figure 1.1

Figure 1.1: Overview Scenario 1

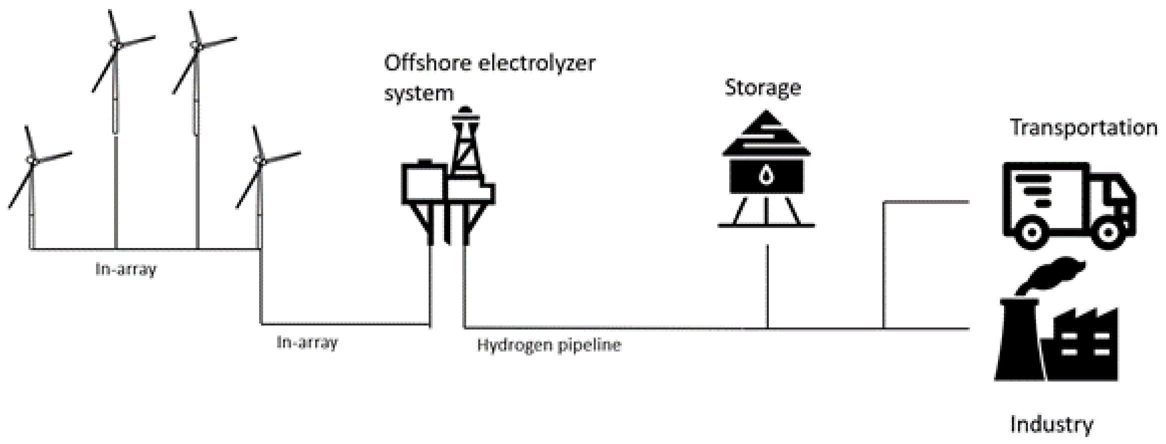


The offshore windfarm is connected to an offshore transformer station, connected to electrical cables. Electricity is then transported through cables to an onshore transformer, before the electricity is connected to the power grid.

1.1.2 Scenario 2

In the second scenario, we investigate the option to produce only hydrogen at an offshore located electrolyzer for sale.

Figure 1.2: Overview Scenario 2

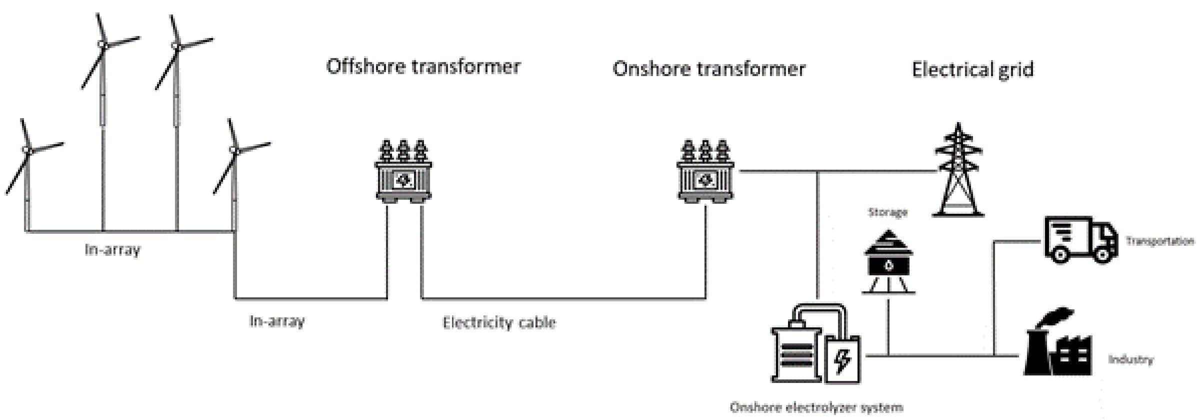


The power produced by the windfarm is converted into hydrogen at an offshore placed electrolyzer. Further, the hydrogen is transported through pipelines as gas to a hub onshore, and consequently sold to potential buyers.

1.1.3 Scenario 3

The third scenario includes a switching option between direct electricity sale and hydrogen production through an onshore located electrolyzer. An economic cut-off between hydrogen production and electricity sale is set, determining the production process to maximize revenue.

Figure 1.3: Overview Scenario 3

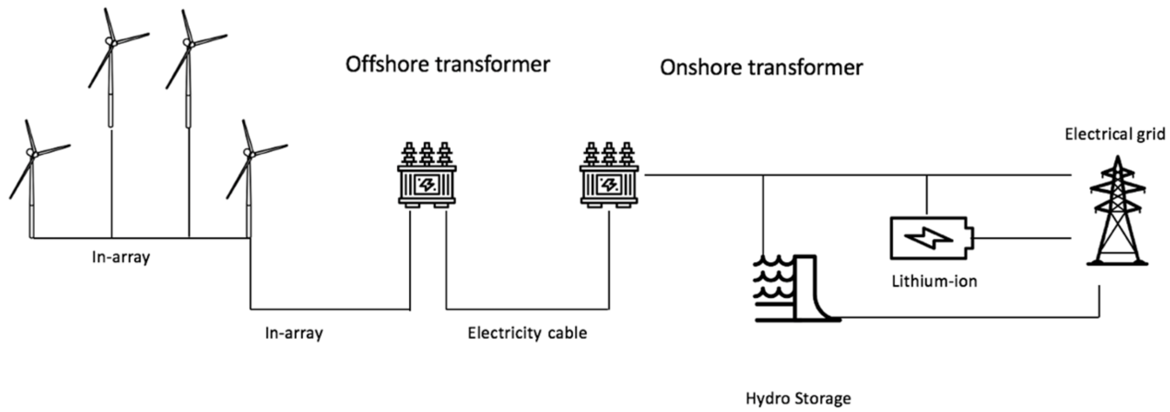


Electricity is produced by the offshore windfarm, and consequently converted through a transformer for transport by electrical cables. The electricity is transformed onshore and connected to both the Norwegian electrical grid, and an onshore electrolyzer system.

1.1.4 Scenario 4

In the fourth scenario, we investigate two alternative storage facilities, lithium-ion batteries and pumped hydro storage. By switching between direct sale and storage, the scenario exploits fluctuations in the electricity price.

Figure 1.4: Overview Scenario 4



The produced electricity follows the same path to shore as previously described in scenarios one and three. At shore, the electricity is sold directly at the power grid in peak-price hours and stored for later sale in off-peak hours.

1.2 Literature review

The offshore wind sector being increasingly examined due to escalating attention to mitigate climate changes. With the fast development in technology, and the expanding utilization of economies of scale, research in the field is struggling to follow along. This leads to gaps in the space of valuation and benefits of economies of scale utilization of large-sized wind farms, including the vast increase in turbine rated power, to be filled. In a thorough valuation case study of the Dogger-bank wind farms, Osmundsen et al. (2021) used a discounted cash flow approach to calculate an internal rate of return of 5.6%.

The report illuminates the uncertainties in estimating costs due to a lack of transparency within the industry. Another aspect of the cost estimation was the recurring tendency for cost overruns, potentially due to an optimistic tender offer design in order to be awarded the contract. Afanasyeva et al. (2016) examine the economic consequences of changes in input variables on the net present value. They emphasized the importance of electricity generation in relation to the turbine power curve and wind speed, to be above the influence of Capex and the cost of capital on profitability. One of the main challenges of renewable non-deployable energy is the ability to be stored. Dinh et al. (2020) examine the option of producing hydrogen in an offshore electrolyzer from electricity generated at a wind farm. They elucidated the potential beneficial impact of using the location of the wind farm as a fulling station for long-haul offshore transportation. Their paper found the option profitable at a hydrogen price of €5/kg. In another examination, McDonagh et al. (2020) investigated an offshore wind farm connected to an electrolyzer with the option to switch between hydrogen production and direct sale of electricity. One of the main benefits of the system was to avoid curtailments with an increasing share of the energy mix being dependant on weather conditions. Another benefit was the effectively floor capped price of electricity produced determined by the difference between the LCOH and the hydrogen price. From an investor's perspective, the attractiveness of the hybrid configuration increased both by the spread previously mentioned, and the amount of curtailments of energy produced. Chen et al., (2021) highlighted crucial variables to account for in estimating the lithium-ions capability of switching the supply from off-peak- to peak hours, in addition to uncertainties in future developments. While Connolly et al., (2011) used an optimization algorithm to evaluate a pumped hydro storage facility. They provided evidence of the sensitivity in profits in relation to the ability to predict next-day prices.

2 Background

In the following chapter we introduce key concepts for understanding the evaluation of the four different scenarios. Electricity generation is relevant for all four scenarios, while understanding of Norwegian electricity markets is relevant for scenario 1,3, and 4. A understanding of hydrogen is key for understanding the potential revenue in scenario 2 and 3.

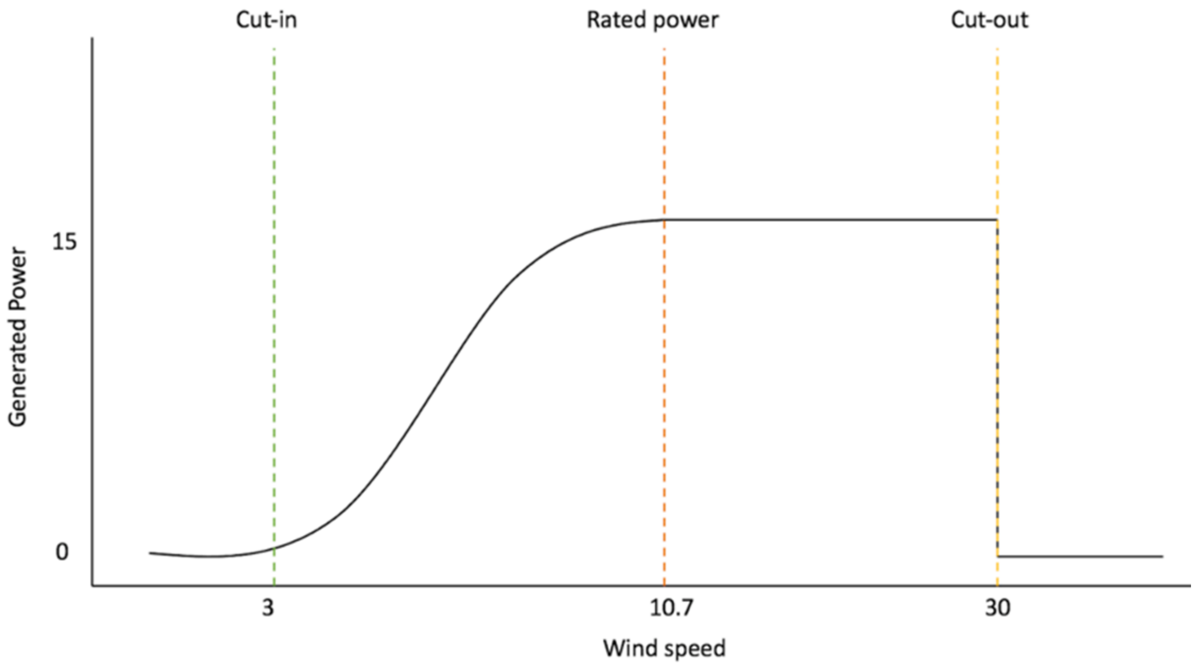
2.1 Offshore wind

The amount of electricity available for further use or direct sale transmitted to shore is a significant part of the revenue calculation in all four scenarios. The following chapter will give an overview of how the amount of electricity generated and transmitted to shore is calculated. In addition, we elucidate the sources of power loss in the two processes.

2.1.1 Electrical generation

Primarily, two factors determine the amount of electricity generated, the available wind energy for conversion, and the power curve. The available wind energy is a relationship between the velocity, air density, and swept area of the turbine, meaning larger turbines generate more electricity at lower wind speeds (Sarkar & Behera, 2012). From the amount of wind energy, the output is determined following the turbine's power curve. The power curve is a non-linear relationship between wind energy and energy output, meaning the marginal electricity output is non-constant along the power curve. Usually, a turbine has a cut-in speed of 3-4 m/s and a cut-out speed of 25-30 m/s. The thresholds for cut-in and cut-out wind speed, represent the levels where the turbine starts generating electricity and stops to mitigate damage to the turbine. Usually, a wind turbine reaches peak electricity production around 12-17 m/s and stays at the level of electricity production until the cut-out speed (Researchhubs, 2015).

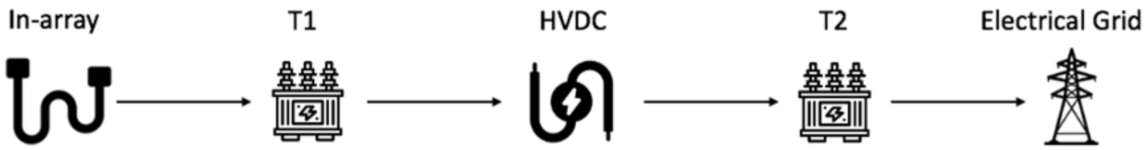
Figure 2.1: Power curve of a Vestas 15MW turbine



2.1.2 Transmission network

Generated electricity for sale into the electric grid necessitates transport through a transmission system. The transmission system consists of all components responsible for efficiently transporting energy captured from each turbine presented in Figure 2.2

Figure 2.2: Overview transmission system



First, individual wind turbines are grouped into a common electric network for cost-efficient transportation to transformer one (T1). In T1, the voltage level of the electricity is increased for more efficient transport in subsea cables back to shore. In the long-distance transmission from T1 to the onshore transformer (T2) through a subsea electricity cable, two options are commonly used: high voltage alternating current (HVAC)- and high voltage direct current (HVDC)- cables. The HVAC cable is beneficial in distances up to

70km, while the HVDC is superior in distances above (Xiang et al., 2016). For this paper we will use HVDC cables due to the distance to shore.

The required voltage level to supply electricity into the grid network is 132 kV (Kjerland, Agder Energi, 2021). The scenarios involving electricity supply into the grid require an additional transformer for voltage regulation. In theory, it is possible to transmit the electricity from the offshore transformer at sufficiently high voltage levels to avoid the need for an onshore transformer. However, this requires a constant amount of energy transmitted, unfeasible for an offshore wind farm. Therefore, an onshore transformer is needed to supply electricity to the grid.

2.1.3 Power loss

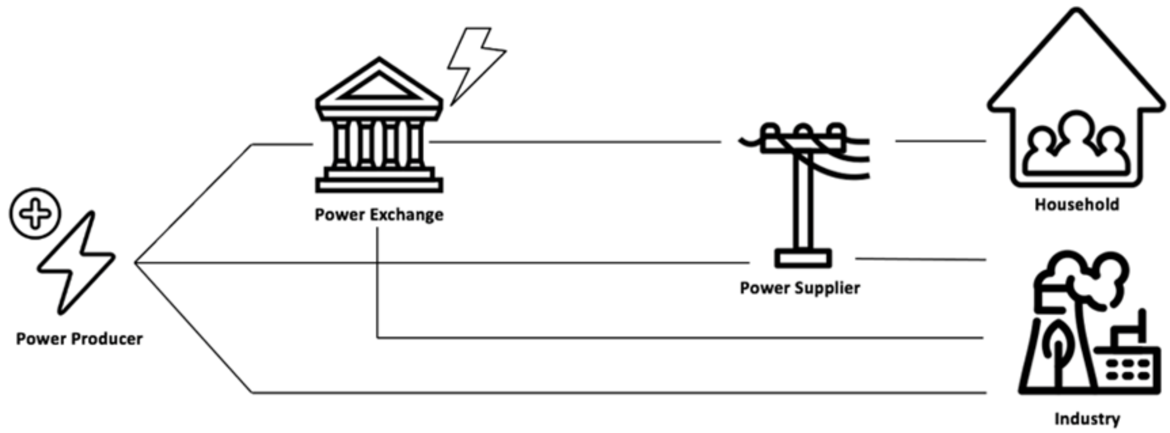
For an offshore wind farms, power loss originates from three sources: wake effects, generator efficiency, and transmission. Each turbine capturing wind energy creates a turbulence effect, causing available wind velocity to decrease for co-located turbines. Wake losses cause the amount of wind to be reduced, meaning the wind speed to reach the rated power is increased. Thus, the effect of wake losses on the power output is differentiated across the power curve. The distance between each turbine is balanced between inter-array cabling cost and wake losses, leading to an optimization to be conducted (Shen et al., 2021). The generator's efficiency is usually denoted in a percentage of energy output in relation to the available wind energy (Sarkar & Behera, 2012). The third source of power loss occurs in the transmission network from regulating the voltage levels in T1 and T2, and through the HVDC subsea cable.

2.2 Electricity power market

2.2.1 Norwegian power market

The Norwegian energy market is built on a free competition principle. The law of energy implemented in 1990 allows anyone to apply for electricity production and distribution in Norway (Energiloven, 1990, §2-1). In Norway, the infrastructure consists of five different bidding zones located in: East (N01), South (N02), Mid (N03), North (N04), and West (N05), operating as an integrated market with some transmission restrictions (NordPool, 2021b). In an elongated country like Norway, a bottleneck for electricity distribution is the integration of the transmission grid between the different regions. The ability to transport from areas with an electricity surplus to areas with a deficit is not always feasible, due to restrictions in the capacity of the transmission network. Thus, the difference in supply and demand across regions leads to variation in electricity prices (EnergiNorge, 2017). For an offshore wind farm, the price of generated electricity is therefore dependent on the wind farm's location.

Figure 2.3: Illustration of the Norwegian electricity market



2.2.2 Price formation

In total, the electricity market consists of two submarkets, where the day-ahead market is the primary market. In addition, we have an intraday market to ensure electricity delivery to end-users. With an increasing share of the energy mix coming from non-deployable renewable resources, the need for an efficient intraday balancing system increases (NordPool, 2021a).

2.2.3 Day-ahead market

The day-ahead market price is determined based on the equilibrium of supply and demand. The electricity producers have a window to determine the amount of power to supply in each specific hour the following day. Accordingly, the demand for electricity from the end-users is estimated and matched against the supply in an algorithm. The system price in each region is then calculated. Each producer and distributor of electricity is respectively obligated to deliver and consume the amount of electricity determined by the Nordpool algorithm, based on price and quantum presented at 12:45 CET for each region for the following day (NordPool, 2021d).

2.2.4 Intraday market

The intraday market works together with the day-ahead market to balance the supply and demand for physical delivery of electricity to end-users. The sub-market allows market participants to manage unexpected changes in supply and demand. Until one hour before the physical delivery, trading is taking place to secure accurate delivery of the amount demanded. The capacity of supplying electricity through the intraday market is limited to the volume spread between supply and demand in each specific hour (NordPool, 2021a).

The volume in the two markets are significantly different. In 2020, the volume of supply and demand in the intraday market was 1% of the amount traded in the day-ahead market (NordPool, 2021c) (NordPool, 2021e). It would not be feasible to provide the amount of electricity generated at the wind farm through the intraday market. In a switching scenario with an option to store electricity or produce hydrogen, the price is unknown in the decision-making movement. Maximizing revenue requires some forecasting to estimate the optimal use of the generated electricity. However, the intraday market enables surplus or deficit in power generation (e.g. unexpected wind velocity) to be handled without any major implications.

2.2.5 Curtailments

Curtailments are a deliberate reduction in power inflow to the electricity network. Curtailments are transmission constraints in periods with oversupply or periods with tail events of weather conditions (Bird et al., 2014). The occurrence of curtailments in the Norwegian power market is a significantly infrequent event (Trading desk, NordPool, 2021). Therefore, it would not affect the amount of electricity supplied and consequently the revenue stream.

2.2.6 Tariffs

The Transmission system operators TSOs are responsible for stable electricity supply and OM of the high-voltage central transmission network. To enable an efficient system, tariffs on various market participants are included. For the supply of produced electricity, the production fees and mark-up for system operation are set to NOK0.0143/KWh (Statnett, 2021).

2.3 Hydrogen

The following section will present what hydrogen is, how it is produced, and the potential future use cases to support hydrogen demand. A key differentiator between hydrogen and electricity is that hydrogen is a form of chemical energy and not just electrons. This differentiator makes hydrogen an attractive solution in meeting future energy needs due to its ability for efficient energy storage.

2.3.1 Hydrogen production

Although hydrogen is the most abundant chemical in the universe, it requires separation from its natural chemical bonds as water or biomass. Hydrogen production can be done through various methods. However, only water electrolysis is relevant for offshore wind production.

Currently, there is around 70 mt of demand worldwide for hydrogen, according to IEA (2019). The current method of meeting this demand is with fossil fuels, with natural gas being the primary production method. Less than 0.7% of hydrogen is produced utilizing renewable energy or fossil fuel facilities equipped with carbon capture, utilization, and storage (CCS). This leads to current hydrogen production producing an estimated 830 $MtCO_2$ per year. Hydrogen has in recent years been in popular literature divided into different groups based on production methods. Green hydrogen is defined as hydrogen produced from renewable power, according to IRENA (2020). Only a minuscule percent of the current output is green hydrogen as production currently stands. Blue hydrogen is hydrogen produced from sources with a high CO2 blueprint but utilizes CCS to reduce its climate footprint. Gray hydrogen is hydrogen produced by coal and natural gas without

CCS. Gray hydrogen is the primary production method currently and accounts for the climate footprint associated with hydrogen.

2.3.2 Water Electrolysis

In this thesis, we will examine the usage of an offshore wind farm as a producer of hydrogen. The most suitable methods that can be used are different water electrolysis configurations. The most common methods are alkaline electrolysis (AE) and polymer electrolyte membrane (PEM). Water electrolysis produces hydrogen by splitting H_2O into H_2 and O_2 using electricity.

2.3.2.1 Alkaline water electrolysis

Alkaline water electrolysis is the process of having an anode and a cathode connected through an external energy source while submerged in an alkaline electrolyte that is mixed with water.

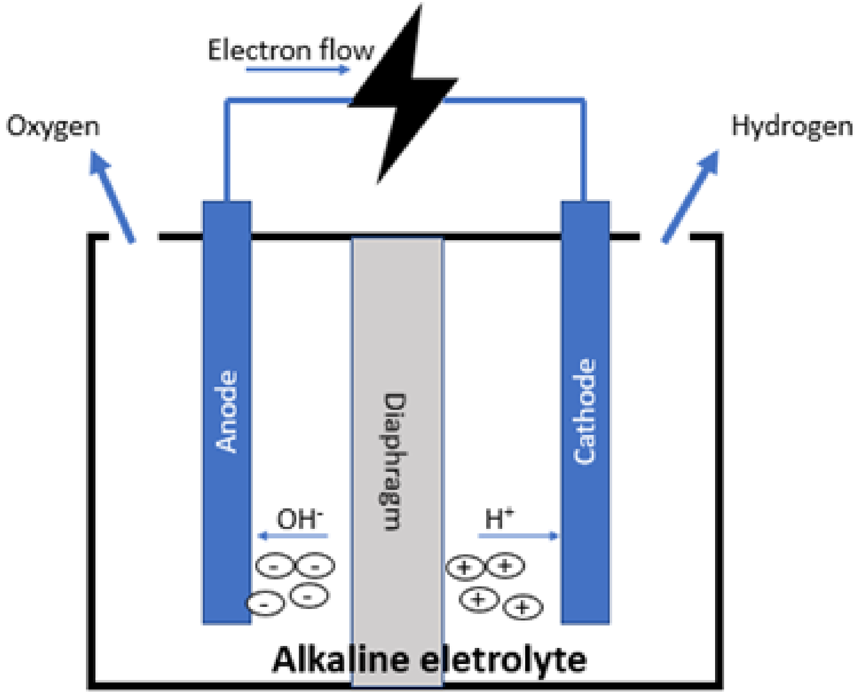
The chemical reactions are:

$$\text{Anode: } 2OH^- \text{ -> } \tfrac{1}{2}\, O_2 + H_2O + 2e^-$$

$$\text{Cathode: } 2H_2O + 2e^- \text{ -> } H_2 + 2OH^-$$

$$\text{Globally: } 2H_2O \text{ -> } 2H_2 + O_2$$

Figure 2.4: Illustration of Alkaline water electrolysis



The flow of electrons leads to a breaking of the H_2O being split into a positively charged hydrogen atom and a negatively charged OH. They pass through the diaphragm to react to the positively(negatively) charged anode(cathode) and produce O2 and H2 gasses that are connected. Nickel is often used for the anode and cathode due to its cost and availability. Potassium hydroxide (KOH), or sodium hydroxide (NaOH), is commonly used for the alkaline solution.

2.3.2.2 Proton exchange membrane electrolysis

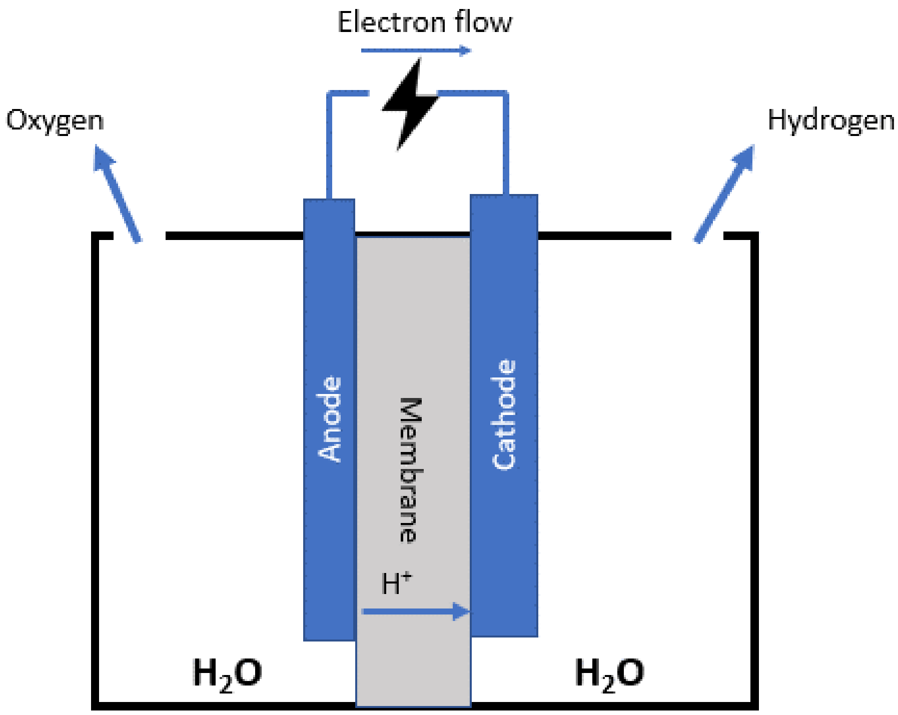
A proton exchange membrane (PEM) utilizes much of the same basic chemistry as alkaline electrolysis. An anode and a cathode are submerged in H_2O, separated by a membrane. An electrical current is run between the anode and the cathode. This produces the chemical reaction:

$$\text{Anode: } 2H_2O \text{ -> } O2 + 4H^+ + 4e^-$$

$$\text{Cathode: } 4H^+ + 4e^- \text{ -> } 2H_2$$

$$\text{Globally: } 2H_2O \text{ -> } H_2 + O_2$$

Figure 2.5: Illustration of Proton exchange membrane electrolysis



The positively charged hydrogen atoms pass through the membrane. The oxygen is evaporated as gas, and the negatively charged electrons pass through as electrical current. The positively charged hydrogen atoms then react in the cathode with the negatively charged electrons to form H_2.

2.3.2.3 Comparison of electrolyzer systems

Both systems have their advantages and disadvantages compared to the other. The advantages of AE are the materials' availability and its proven track record in converting H_2O into hydrogen. The main disadvantage of using AE is that constant power is necessary for full optimization, a potential issue for usage with renewables having variable power outputs. AE requires an alkaline solution that must be swapped out and suffers from corrosion, unfavorable if placed in an offshore environment (Guo et al., 2019). The components used in a PEM are often expensive. The cathode is often Iridium based oxides, and the anode is carbon-supported platinum particles. PEM allows for high variable loads and is particularly suited for coupling with renewable production. PEM is about 1/3 of the size of an alkaline electrolyzer. Its only needed input is water, compared to alkaline electrolyzers, which need water and an alkaline solution for hydrogen production. (Guo et al., 2019). Due to its high operating variability, size, and maintenance qualities, PEM is chosen as the electrolyzer configuration in Scenario 2 and 3.

2.3.3 Hydrogen storage

Hydrogen can be stored in two-unit conditions: gas or liquid. The storage of gas with no changes to pressure or state requires large, confined areas to contain this due to unpressurized hydrogen gas having a low volumetric energy density. Solutions such as pressurizing the gas or converting it to a liquid state are often preferred. The conversion point of hydrogen to a liquid occurs at -252.87C. Comparing this to the conversion point of natural gas, occurring at -162C. This lower temperature requires higher energy inputs to achieve liquefaction. Table 2.1 lists volumetric and gravimetric energy densities of standard fuels.

Table 2.1: Overview of common fuel properties

Material	**Energy per kilogram**	**Energy per liter**
Hydrogen (liquid)	143	10.1
Hydrogen (compressed, 700 bar)	143	5.6
Hydrogen (ambient pressure)	143	0.0107
Methane (ambient pressure)	55.6	0.0378
Natural gas (liquid)	53.6	22.2
Natural gas (compressed 250 bar)	53.6	9
Natural gas	53.6	0.0364
LPG propane	49.6	25.3
LPG butane	49.1	27.7
Gasoline (petrol)	46.4	34.2
Biodiesel oil	42.2	33
Diesel	45.4	34.6

As we observe from the energy per liter, converting hydrogen to a liquid is preferable to pressurizing, although costs and benefits must be compared due to energy necessary for liquefaction (Bossel & Eliasson, 2002). In scenario 2 3 hydrogen is produced and short-term storage is needed before sale. As the costs of liquefaction are high, storage as a gas is chosen.

Hydrogen can also be absorbed into materials or altered into different chemicals for storage.

2.3.4 Transport of hydrogen

As described above, hydrogen can be transported as a gas or a liquid. For this thesis, the primary method analyzed is the transport from an offshore hydrogen production facility, compared to transporting the potential energy as electricity.

The simplest method of transporting hydrogen would be as a gas without pressurizing or liquefaction. The transportation of hydrogen as a gas in pipelines has key advantages compared to transportation in storage vessels. Although hydrogen has a higher energy per kilogram than all common fuel sources, the energy stored per liter is significantly lower. The lower volumetric density poses issues during transport, as the primary constraint is volume, not weight. Due to the chemical properties discussed over, hydrogen offers little in the way of efficient transport in confined storage facilities. Building new pipelines, or utilizing current natural gas pipelines, has been suggested to facilitate efficient hydrogen transfer as a pan-European solution.

Transfer through pipelines poses potential challenges. Hydrogen is the smallest and lightest chemical element in the universe and has long posed challenges to metals through hydrogen embrittlement. Hydrogen embrittlement occurs when hydrogen reacts to materials, causing structural integrity loss. Currently, there are efforts to investigate the facilitation of current natural gas pipelines, and the materials required if new pipelines are built (Woznicki et al., 2020). For new pipelines being built such as in scenario 2 pipelines must be constructed to withstand embrittlement.

Hydrogen often requires compression for pipeline transport. This requires the gas to be pressurized before being injected into the pipeline for transportation to shore.

2.4 Hydrogen applicability

In the following section we provide information relating to current and future use of hydrogen. Both are key to understanding the future potential market size for hydrogen sale as in scenario 2 and 3.

2.4.1 Current uses

Refining

Refiners of hydrocarbon products use hydrogen to lower the sulfur content of diesel. Hydrogen bonds with the sulfur to create hydrogen sulfide, which is later captured and further treated. Hydrogen used for refining is the most significant consumption source (IEA, 2019). Sulfur is removed from the fuels to lower the emissions of the end product. Regulatory changes have also focused on the sulfur content in fuels. IMO 2020 introduced a rule that limits the sulfur limits contained in fuels used in ships (IMO, 2019).

Ammonia

The process of ammonia production is highly energy-intensive. Ammonia is the 2nd largest usage of hydrogen and consumes approximately 31 Mt of H2. Currently, most hydrogen utilized in ammonia production is produced on-site by natural gas or coal (IEA, 2019). There are significant opportunities to drive down emissions by adopting green hydrogen as the primary source of hydrogen. There are currently pilot projects utilizing offshore wind to produce green ammonia (Orsted, 2020).

2.4.2 Future uses

Hydrogen is being experimented with in multiple uses. The future use of hydrogen is essential for the future demand for hydrogen. Therefore, to calculate revenues of hydrogen production, it is helpful to increase the knowledge of possible applications in the future.

Hydrogen is being tested all across the transport sector. The sector hydrogen makes the most sense in is aerial transport. One of the main properties of hydrogen as an energy carrier in a liquid form is the energy density per kg of potential fuel. This makes hydrogen particularly suited for planes, where weight is crucial when choosing a zero-emission fueling source. Airbus is currently developing three prototypes utilizing hydrogen as the primary fuel source (Airbus 2020). The longest-range version is set to have a range of 3 700 km. It is a significant drop-off compared to current newly released concepts such as the Boeing 787 Dreamliner with a range of 13 530 km (Boeing, 2021).

The global shipping industry currently accounts for 2.89% of global greenhouse gas emissions (GHG); if current trends continue, the expected GHG will increase from 90%

of 2008 levels to 90-130% of 2008 based on different long-term economic scenarios (IMO, 2021). Prototypes are currently being developed in the lead by Wilhelmsen set to utilize liquid hydrogen as its fuel source. Due to the chemical properties of liquid hydrogen having a low volumetric density over other alternatives such as green ammonia, these are considered a fuel source on longer hauls (IEEE, 2021).

Passenger automotive vehicles have arguably seen the most significant push in adopting emission-free fueling sources. Electric vehicles utilizing battery technology have seen advancement thanks to battery technology advancements and improvements in recharging and infrastructure to drive increased adoption. Hydrogen-powered cars have seen lower adoption. According to Volkswagen (2020), there are 130 000 battery-powered cars in Germany, compared to 507 hydrogen-powered vehicles. Volkswagen also summarizes the current sentiment regarding hydrogen-powered cars as such: "The conclusion is clear: in the case of the passenger car, everything speaks in favor of the battery, and practically nothing speaks in favor of hydrogen."

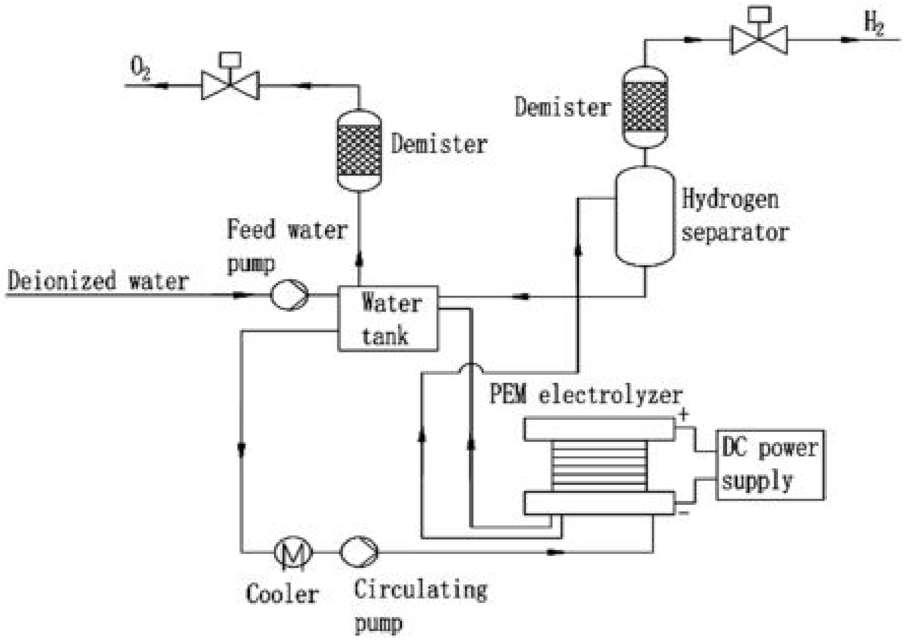
Automotive vehicles requiring longer ranges or having heavier transport have different requirements for operating. They need to have high operational windows and a much higher expected usage range. Current battery technology allows trucks to travel at a maximum of 500 miles (Tesla, 2021). Current prototypes for hydrogen vehicles qualify for a range of 600 miles. Aside from fuel costs, trucking companies face another essential cost, labor. Hydrogen vehicles have a key selling point over battery-powered cars; they allow fast refueling cutting labor costs.

Steel production is one of the most significant contributors to the total global GHG emission. In 2018, iron-ore-based steel production emissions constituted 8% of the total global emissions (Mckinsey, 2020). Along with the increase in living standards, population, and development in non-industrialized countries, the steel demand is expected to increase until 2050. Thus, the most common technique to meet demand is to use coking coal in combination with heated air to reduce iron ore for steel production. Using hydrogen as a substitute can both benefit the process's emission and be beneficial economically (Bhaskar et al., 2020).

2.5 PEM hydrogen production process

In the following section a PEM electrolyzer system is presented including various operational details.

Figure 2.6: PEM electrolyzer system



2.5.1 Power system

Power from the wind farm is used to power the electrolyzer, a compressor, and a reverse seawater osmosis system. Compared to electrolyzers supplied in DC power, wind farm power is in AC. Most modern PEM system configurations contain rectifiers allowing conversion from AC-powered renewable sources or AC-powered grid configurations into DC power. Siemens and Lettenmeier (2020) states that power supply losses are accounted for in electrolyzer plant efficiency in their efficiency whitepaper.

2.5.2 Start up and shutdowns

When discussing the start-up times for an electrolyzer configuration, there are two main possibilities to look at: cold start-ups and warm start-ups. Cold start-ups occur when the electrolyzer is not pressurized or warmed to the correct temperature to support the optimal production of hydrogen. Warm start-ups occur when an auxiliary power source is connected to the electrolyzer to keep pressure and temperature optimal for hydrogen production. In their review, Buttler & Spliethoff (2018) find that state-of-the-art PEMs have cold start-up times of 5-10 minutes and warm start-up times of less than 10 seconds.

Future trends in cold start-up times remain uncertain. Their report from 2014 Fuel Cells and Hydrogen Joint Undertaking estimates a cold start time of 30 seconds in 2020 and 10 seconds in 2030. If this were the case, this cuts the difference in start-up times to a minuscule difference between the two setups. As the estimates for future start-up times vary widely we will use a start-up time of 3 minutes for our analysis to remain conservative.

2.5.3 Water supply

The electrolyzer feeds in deionized freshwater through a water tank. The water is fed into the electrolyzer along with the electrical current from the power source, and the electrolysis process as described in section 2.3.2 begins. The freshly produced hydrogen exits the electrolyzer, and is transported to a hydrogen separator, deoxidized and can be released to compression for transport.

2.5.4 Compressor

The pressure of hydrogen exiting the electrolyzer is in most current PEM systems at 30 Bar. A higher pressure must be achieved for the gas to be transported through pipelines. A compressor must be coupled with the electrolyzer to facilitate this. Looking at the state-of-the-art PEM systems like the Silyzer 300 from Siemens can customize the output pressure to fit the customer's needs (Schönberger et al. ,2016). However, for this analysis, an external compressor is assumed for pressurizing the hydrogen gas to the required pressure for transport through pipelines if installed offshore.

2.5.5 Desalination

For an offshore configuration of hydrogen production, seawater can be utilized when the system is coupled with a seawater reverse osmosis (SWRO). SWRO is a mature technology that takes in seawater and filters it through reverse osmosis. Reverse osmosis is a process where water is filtered through a membrane, utilizing pressure differences in compartments separated by the membrane. This allows water to filter through, leaving a high salinity concentrate and unwanted particles left. This allows for the extraction of fresh water and a brine solution (Al-Karaghouli et al. ,2013). The brine solution could be released back into the ocean. The fresh seawater is taken into the electrolyzer system, then deionized and taken into the electrolyzer.

2.5.6 Pipelines

Transporting hydrogen gas through pipelines has two main upsides compared to transporting electricity through cables. First, the capital cost of pipelines is lower compared to electric cables. Second, very little potential energy is lost.

3 Data

3.1 Revenues

In the following section we give an overview of potential revenue streams for the different scenarios.

3.1.1 Wind speed

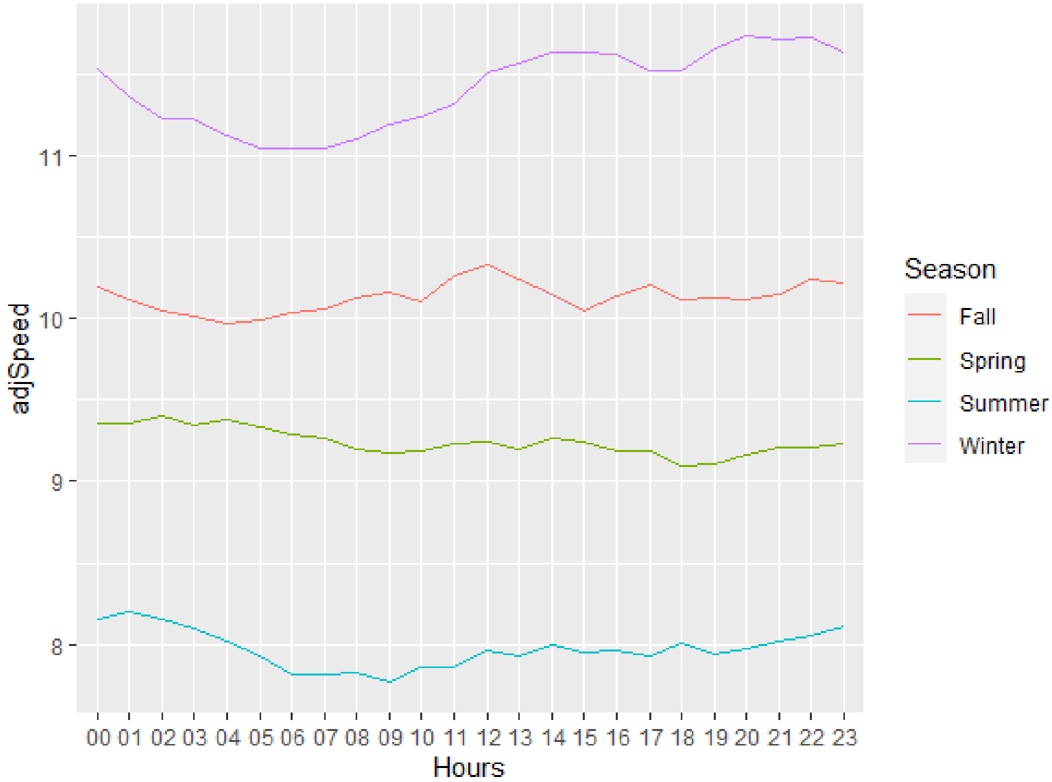
To place a hypothetical wind farm in an offshore area off the coast of Norway, a key input factor are wind speeds. We use wind data provided from the offshore platform Ekofisk (Norsk Klimaservicesenter 2021).

The data is gathered on an hourly basis from 01.10.2015 - 01.10.2020. Ekofisk stopped publishing hourly data from 01.10.2020. A five-year period is chosen to get a representative presentation of seasonality in wind data. Based on conversations with Metrologisk Institutt, Ekofisk is located 69 meters above sea level. As the turbine is 261m above sea level, we adjust the wind speed according to the wind profile power law detailed in Appendix A.

Table 3.1: Summary statistics of wind speed

Statistic	N	Mean	St. Dev.	Min	Pctl(25)	Pctl(75)	Max
Windspeed	43,730	9.678	4.497	0.242	6.411	12.580	33.510

Figure 3.1: Average wind speeds per hour per season



The data displays seasonality. Figure 3.1 shows the average observed wind speeds divided into seasons. The average wind speeds vary highly by season. During the winter(summer), wind speeds are at the highest(lowest) level.

Pryor and Barthelmie (2010) find that it is unlikely that Europe will experience a change in mean wind speeds more than the current inner-annual variability. Accounting for this, the wind data is not adjusted for climate change in the period examined.

To construct a normal year for cash flow valuation, averaging the observations creates a upward bias due to the wind speed calculation described in Appendix A. To find a normal year we choose the year with the median average wind speeds which is 2016. 2016, is then the base for our hourly wind observations.

3.1.2 Electricity prices

We utilize ELSpot rates gathered from NordPool for day-ahead prices as the base for our forecast model. The data is hourly from 01.01.2015 to 15.12.2021. This period is chosen to capture fluctuating annual seasonality and the increasing integration of electrical cables transporting electricity abroad. This gives us a total of 60,977 observations. The data contains prices for all areas of the Norwegian power market and are adjusted to 2020 prices using KPI data (SSB 2021). As the location chosen for the wind farm is off the south western coast of Norway, the relevant electricity region is NO2. Therefore, we use NO2 prices for this analysis. The prices provided by NordPool used for revenue calculation are denoted without any form of fees (NordPool, 2021d).

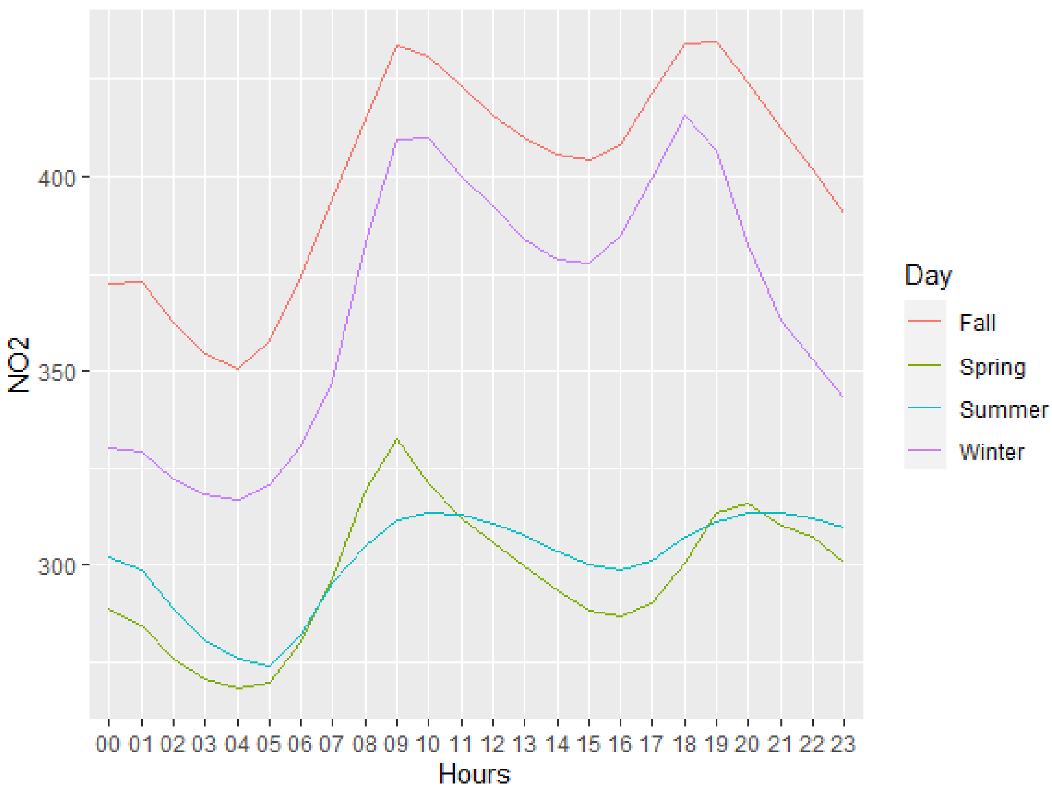
Table 3.2: Summary electricity prices region NO2

Statistic	N	Mean	St. Dev.	Min	Pctl(25)	Pctl(75)	Max
NO2	60,977	340.9	236.2	−19.7	224.4	421.3	4,187.0

3.1.2.1 Seasonality

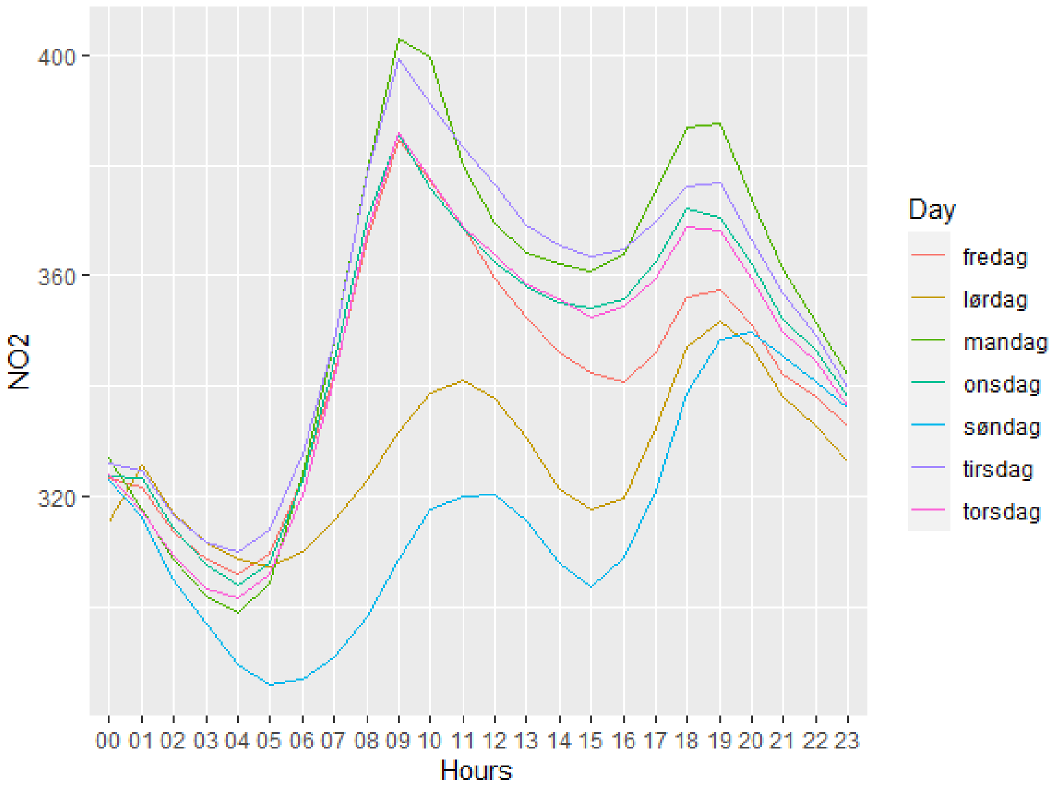
Electricity prices display high seasonality based on four main factors: Annually, Seasonally, daily, and hourly. Electricity prices fluctuate with consumption, with higher(lower) peaks in periods with high(low) consumption.

Figure 3.2: Average prices per season per hour



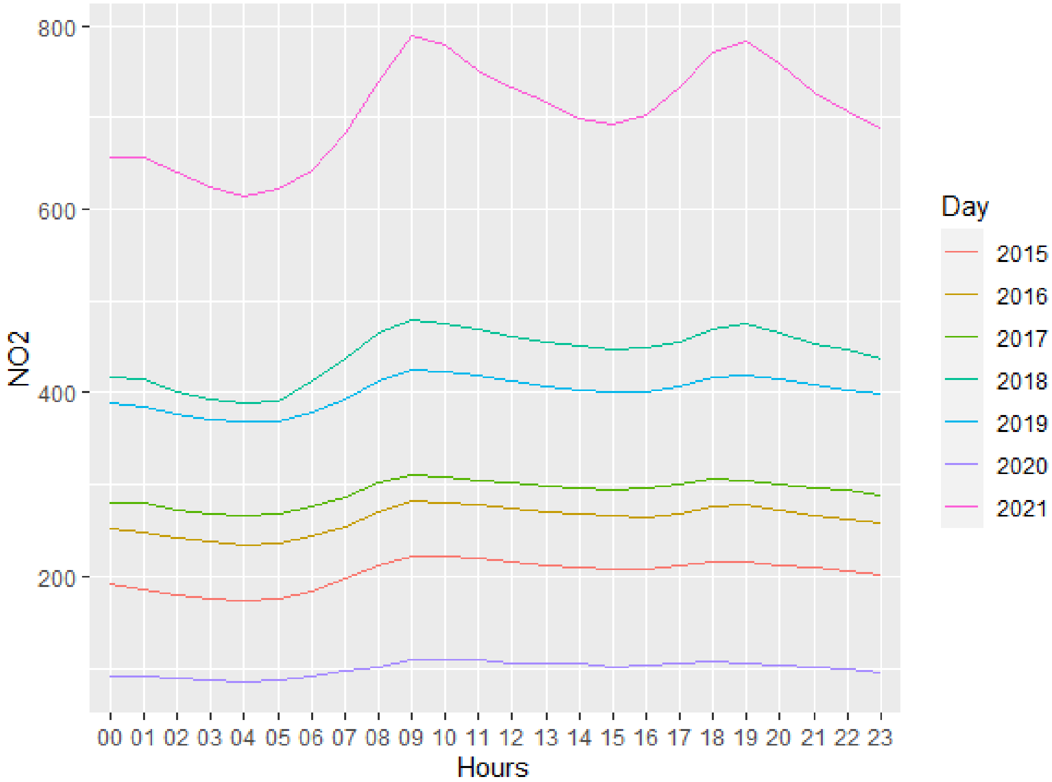
Higher(lower) electricity prices are observed during winter(summer). This relationship is the inverse of what is observed in the average wind speeds per season in section 3.1.1 — leading to higher revenues compared to a negative correlation between wind speed and electricity prices.

Figure 3.3: Average prices per day per hour



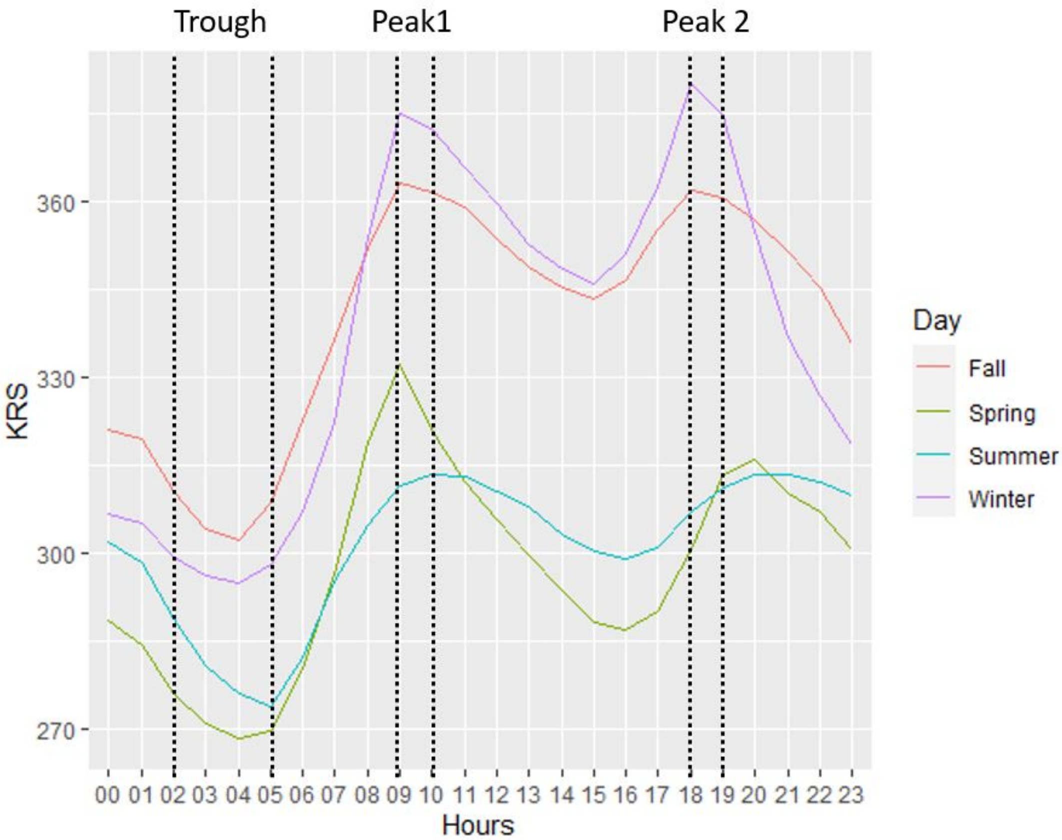
As we observe from Figure 3.3, the prices vary highly by consumption patterns by electricity usage. Weekdays follow the same patterns, with two prominent peaks concentrated in the morning and around dinner time. Weekends follow the same patterns but with a generally lower price level as consumption is spread out.

Figure 3.4: Average prices per day per year



Electricity prices also vary by year. As Norwegian electricity is heavily weighted towards hydropower, annual price swings are heavily influenced by available water reservoirs and thus by the level of precipitation. These are sometimes referred to as wet years and dry years.

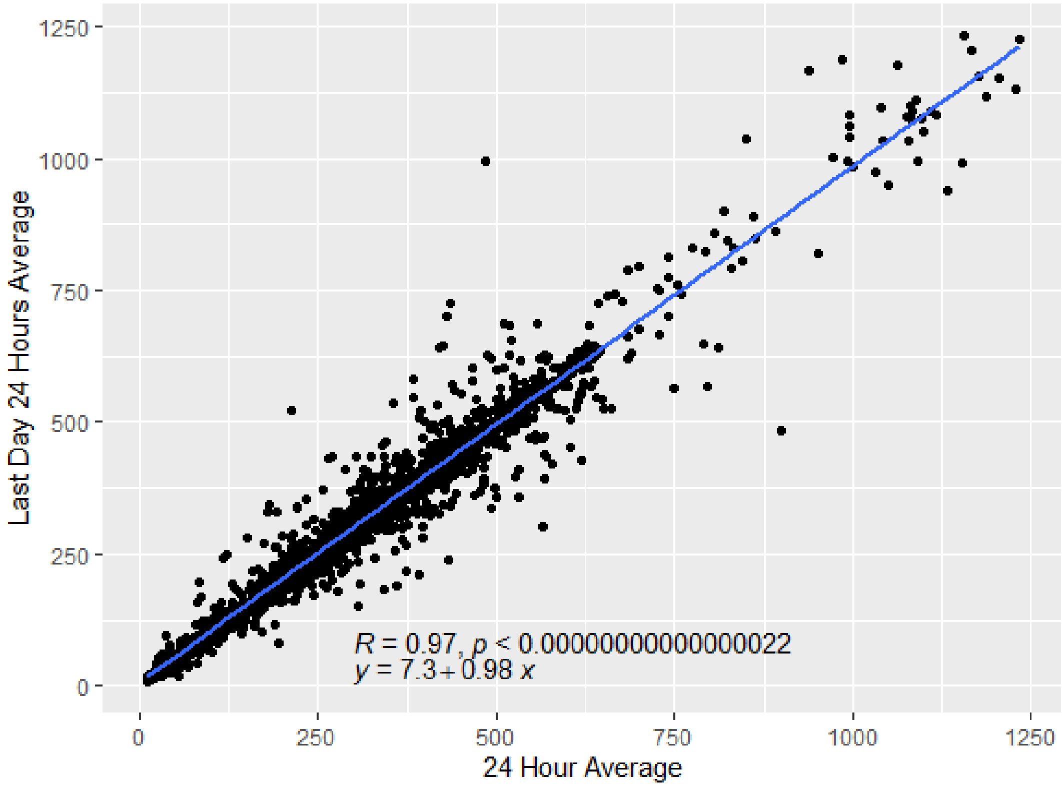
Figure 3.5: Electricity price profile for battery storage



Electricity prices display the same daily general price patterns of low prices during the night and higher during the day in all seasonality factors discussed above. In scenario 4, a configuration of energy storage in batteries is analyzed. For production planning purposes, the peaks (troughs) above are chosen as the daily energy charge(discharge) periods.[1]

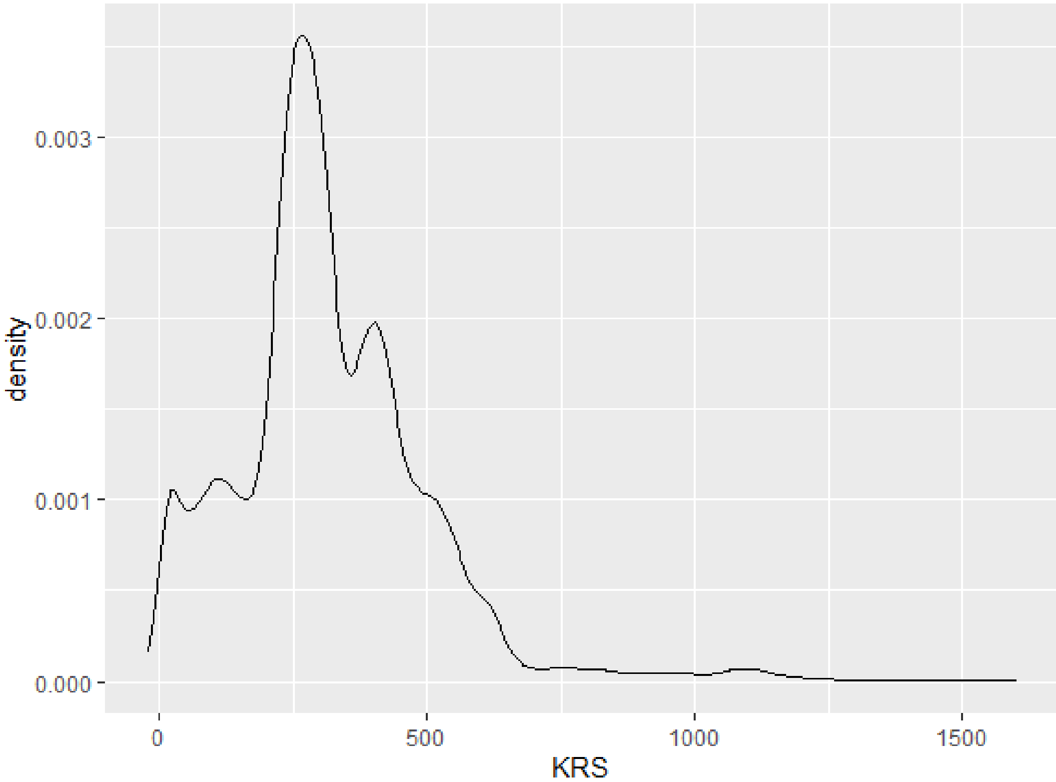
[1]Battery is charged from 02-05, and discharged from 09-10 and 18-19

Figure 3.6: Average daily prices by previous day average price



Much of the observed price can also be explained by previous prices. This relationship allows for higher insight into future prices observed for Day-ahead electricity prices.

Figure 3.7: Probability density function of electricity prices



Electricity prices also display high volatility in periods. This adds value to a potential solution exploiting periods of high electricity prices such as one as Scenario 3. In figure 3.7 the density function of observed prices is presented.

3.1.2.2 Electricity price adjustments

Schwartz and Smith (2000) lay out a model for long term dynamics for commodity pricing in equation 3.1:

$$S_t = \xi_t + \chi_t \tag{3.1}$$

Where prices at point t is compromised by the equilibrium price (ξ) and a short-term deviation from the equilibrium price (χ). Changes in the short-term deviations are not expected to persist over time, only changes in the equilibrium price represent persistent changes in prices.

3.1.2.3 Long term equilibrium price

For the long-term equilibrium price levels we utilize fundamental analysis done by both NVE and Statnett. These are the two most prominent publicly available forecasts for Norwegian electricity prices. Both reports were published in 2020, and detail forecasts for Norwegian energy prices until 2040. As the starting point for our analysis is 2030, and intend to analyze a 25-year investment horizon, we have 15 years that do not have explicit forecasts for Norwegian energy prices. However, we assume that prices are constant at 2040 forecasts. The prices provided are all in real terms and are not adjusted for inflation.

Table 3.3: Electricity prices forecasts

Source	2022	2025	2030	2040
Statnett EUR		40	45	40
Statnett NOK		438.8	493.65	438.8
NVE NOK	400	440	420	420
Combined	400	439.4	456.825	429.4

We have converted the Statnett report into NOK/mWh for consistency as the NVE report is in NOK. The exchange rate used was the exchange rate of 10.97 at day close of the publication of Statnett report 20 October 2020. All prices reported are in 2020 NOK. The forecasted prices have been equally weighted to create the combined equilibrium price used for the forecasted prices.

3.1.2.4 Short-term deviations.

To be able to capture short-term fluctuations in our future prices we utilize the electricity prices for 2015-2021. As the short-term deviations have a mean of zero, we set the mean of the observations to 0 by eq. 3.2

$$Zero\ mean\ price_t = \ Price_t\ -\ \bar{Price} \tag{3.2}$$

To estimate future electricity prices, we use a bootstrapping simulation method to create short-term deviations for our data. For scenario 1, 2, and 4 we take an average of seven years and average them out to one year. As in these scenarios there is no need for production switching. We expect to encounter the average of the seasonality discussed in section 3.1.2.1 and as short-term deviation has a mean of zero averaging it will not cause cash flow implications, under these scenarios. The reason to average observations into one year is for the cash flows to be stable over time, important since we deploy a discounted cash flow method, where the timing of cash flows will affect the result of the analysis. For scenario 3 we construct seven different data sets, based on the seven years[2]. This is then used as the base for revenue optimization. To combine the forecasted prices, we employ eq. 3.3.

$$P_t^{El} = \ Long\ term\ price_{year}\ +\ Zero\ mean\ price_t \tag{3.3}$$

For illustrative purposes, we will explain the construction of the first of the seven price data sets. This will be 2015 since this is the first year of our dataset. We calculate the average price of all observations from 2015-2021. The zero mean price for 2015 will be the price at time t minus the average price found before. This zero mean price is duplicated to create a time series stretching from 2030-2055. The long-term equilibrium price is added to the zero mean observations. This process is repeated for all seven years.

3.1.2.5 Volatility

Both reports detail an expected increase of volatility for future electricity prices. NVE expects future volatility to increase in all seasonality factors discussed in section 3.1.2.1 Statnett also expects higher volatility in their long-term analysis. As both analyses were published in 2020. In 2021, electricity prices have been much higher than in their estimation of future outcome. Thus, we do not increase volatility in the data since we believe this is captured when including 2021.

The future implications of more electricity from wind energy can reverse the positive correlation between wind speed and electricity prices described previously. In their forecasts, both Statnett and NVE include the expected future wind power in Norway and the integration of electricity cables to other countries. They do not find that this will affect the average prices per season.

[2]For 2021, data is gathered until 15. December. To construct a full year data from 16-31. December in 2020 is subsisted in to complete the full year.

3.1.3 Hydrogen prices

While possibilities for hydrogen production and a significant increase in demand are forecasted, green hydrogen production's economic feasibility is required to follow along to enable a transition from polluting energy sources.

Table 3.4: Break-even price for hydrogen to meet cost-parity (Hydrogen Council McKinsey Company, 2021)

Use area	**Break-even $/kg**	**Substituting technology**
Buses	4.40	Diesel
Trains	3.80	Diesel
Trucks	2.50	Diesel
Ammonia (gray)	1.40	Natural gas SMR
Steel (DRI)	0.60	Coal
Building heating	0.50	Natural gas
Shipping	0.60	Ship Fuel
Air planes	0.60	Kerosene

In table 3.4 we present the break-even price of hydrogen to meet cost parity without implications of carbon tax.

To incentivize investments and enable the profitable production of renewable energy, governments worldwide play an essential role in internalizing the positive externalities created. One solution is to increase the CO_2 fee for contaminates, often referred to as the carbon tax. In table 3.5, we present the implied carbon price to meet cost parity of hydrogen for the four most significant areas of applications.

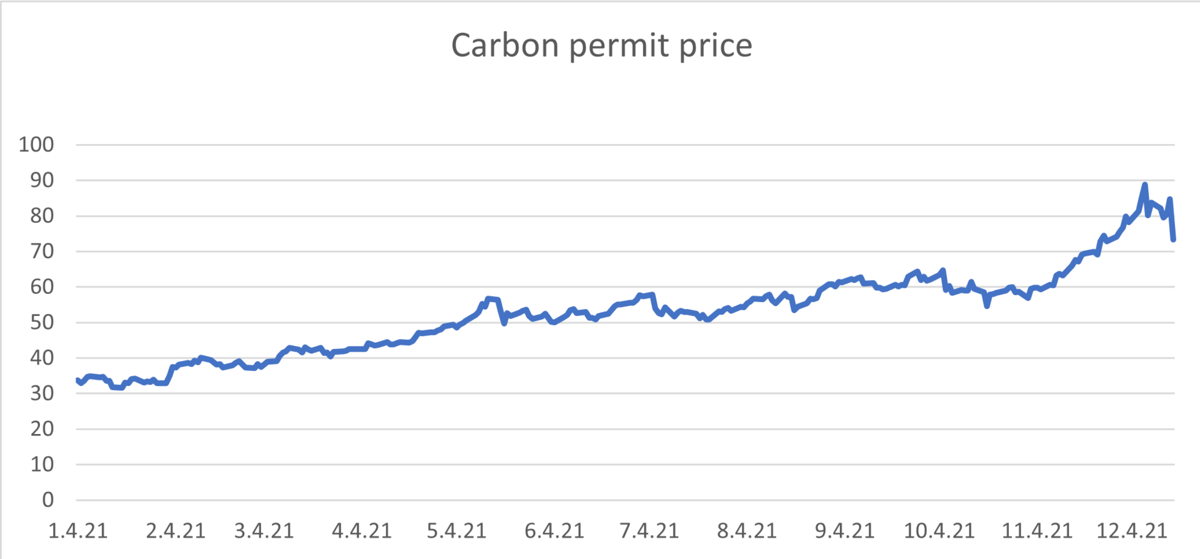
Table 3.5: CO_2 Cost parity(Hydrogen Council McKinsey Company, 2021)

Subsitute	**CO_2 price**
Steel	$80
Gray ammonia	$85
Shipping fuel	$195
Air craft	$200

The energy sources are adjusted to equal amount of energy, a price for hydrogen is set to $2.3/kg as a reference.

Along with the increased interest in carbon permits, the market for EU Carbon Permits is increasingly traded. From 04.01.2021 to 04.12.21, the average price of EU carbon permits, similar to one ton of carbon, was €52.56 or $61.84. In figure 3.8, the development in the price is presented (Ember, 2021).

Figure 3.8: EU Carbon Permits (EUR)



The relationship between table 3.5 and and figure 3.8 presents a development towards cost parity. However, the CO_2 price is not being stabilized at the presented levels, and it is still too early to conclude with the long-term price of EU carbon Permits. The Norwegian government set an ambitious goal of increasing the price of emission to NOK 2,000 or $235.3 by 2030, accelerating incentives for renewable energy creation (Regjeringen, 2021). This carbon tax would make hydrogen a cost effective substitute for many areas.

Although empirical studies explore the input variables to determine a hydrogen price in the following decades, the ability to accurately predict the future price is nearly impossible in the immature market. The application of hydrogen is uncertain and will be of significant impact for the price development. To capture the uncertainties in the analysis, we will use three different scenarios for the hydrogen prices, and assume a constant price over the 25 year period. The base-case for the analysis is set to be $3.5/kg (NOK29.75/kg), and a low- and high- state of respectively $2.5/kg (NOK 21.25/kg) and $4.5/kg (NOK 38.25/kg).

3.2 Costs

In the following section we give an overview of cost relevant for the different scenarios.

3.2.1 Capex Offshore windfarm

The capital expenditures of an offshore wind farm are of significant importance on the ending net present value of the investment. The facility is divided into three components: turbine, tower and foundation.

Table 3.6: Overview Capex offshore wind farm

Name	Unit cost (M)	Units	Currency	Total Cost (M)	Scenario
Vestas 15MW turbine	13.00	67	$	7403.5	1,2,3,4
Foundation	3.50	67	$	1993.25	1,2,3,4
Installations	2.00	67	$	1139	1,2,3,4
Development	130.58	1	£	1436.32	1,2,3,4
Management	31.69	1	£	348.64	1,2,3,4
Insurance	3.48	1	£	38.302	1,2,3,4
In-array-cables	1.00	112.68	£	1363.43	1,2,3,4
Offshore transformer	217.50	1		2392.50	1,3,4
HVDC-cable	1.10	50	£	1815.00	1,3,4
Onshore transformer	182.86	1		1828.60	1,3,4

The total capital expenditures are determined by eq. 3.4.

$$C_{Owf} \;=\; C_t \;+\; C_{FT} + C_I + C_{MD} \tag{3.4}$$

Were C_t represent the cost of the turbine, CFT the cost of foundation and tower, C_I is the cost of installation, and $C_{M\&D}$ represent management and development cost in the pre-operations period.

According to Shafiee et al., (2016) the turbine cost is determined in relation to the rated power (RP), presented in eq. 3.5.

$$C_t \;=\; 3,000,000 * ln(RP) - 662,400 \tag{3.5}$$

However, as argued by Buljan (2020), the increased complexity of increasing the size of a turbine regarding construction is driving the cost of each turbine upwards. The estimated cost of a 15MW turbine accounted for the increased size, and transportation is set by eq. 3.6.

$$Turbine\ cost = 0.8 * mW + mW_{>10mW} * 0,8 * 0,25 \tag{3.6}$$

Foundation

The foundation cost is calculated from the use and price of materials and manufacture. According to Myhr et al.(2014) the cost of a Monopile substructure for a 10 MW turbine is €2,400,000. However, it is plausible to believe the solidity requirements to be escalated due to increased rated power. In a report, Buljan (2020) estimated the foundation cost for a 14 MW turbine to be between $3-4m.

Installation

The installation process consists of transporting the components from the port and installing the turbine and the substructure. Both processes include the use of a Quay-side lift, transportation using a SPIV vessel, and labor. Cost of transportation is calculated by eq. 3.7.

$$C_t = \frac{D_p}{V_s} * P_d * \ Q \tag{3.7}$$

Where D_P is the distance of transportation, set to be 200km, due to an assumption that the port for construction is located approximately 50km away from the closest shore point. V_2 is the speed of the SPIV vessel, set to 10 knots or 18.52km/t (Kaiser Snyder, 2013). P_d is the price of the vessel denoted in hours, set to $120,000 (Pradana et al., 2021). The unit price is multiplied by the 67 turbines and the 67 foundations to estimate the total cost. In addition, the process of installation of the foundation and turbine at the preferred location is $1m, including the use of the Quay-side lift and labor (Buljan, 2020).

Management, development, and insurance In addition to the capital expenditures related to construction and installation, the project will have management, development, and insurance expenses. The cost estimates are built on a 500MW wind farm consisting of 8MW turbines from 2015 (Refsnes, 2015). From their cost structure, we expect management, development, and insurance costs to decrease by 12.95% following the scaling law, presented in eq. 3.8.

$$\frac{C_2}{C_1} = \frac{Q_2}{Q_1}^{\alpha} \tag{3.8}$$

$\frac{\mathrm{C}_2}{\mathrm{C}_1}$:Relationship between cost.

$\frac{\mathrm{Q}_2}{\mathrm{Q}_1}$:Relationship between the size.

α: Scaling factor of the technology

The scaling factor is 0.8 (Baumann et al., 2017). To calculate the power loss, the turbine's rated power is substituted with the total capacity of farms 1 and 2.

The expectations are built on two arguments. First, the utilization of economies of scale benefits. Second, the experience from development and management of a wind farm to increase, but also the information and experience captured from insurance companies, enables decreasing the margin of error surcharge when determining the risk premium.

3.2.1.1 Capex grid connection

The inter-array cable is a 33 kV HVAC cable, clustering turbines together to the offshore transformer. The distance of the inter-array cable needed for the wind farm is 112.684km. This is based on the optimal distance of seven times the diameter of the rotor blades between each turbine (Clayton, 2021). The unit price of 1km inter-array cable cost is £1m (Nieradzinska et al., 2016)

Capital expenditures of transformer one are estimated based on a wide range of literature. Nieradzinska et al. calculated the capital expenditure of an offshore transformer to be approximately £217.5m/GW installed capacity. In another study, MacDonald et al. (2016) estimated the GW cost to be €182.86m. However, this transformer was located onshore.

The HVDC cable cost is estimated from data provided by Nieradzinska et al. (2016), with a cost of £1.1m/km.

Lastly, transformer two is calculated based on the article from MacDonald et al. previously mentioned.

3.2.2 Opex Offshore windfarm

In table 3.7, we present the estimated operating expenses for electricity generation in the wind farm.

Table 3.7: Overview Opex offshore wind farm

Name	Unit cost (M)	Units	Currency	Total Cost (M)	Scenario
OWF	0.01349307	kWh	€	12.88	1,2,3,4
Revnue loss OWF	4.35 %	Electricity output			1,2,3,4
O&M HVDC	2.59 %	Capex			1,3,4
O&M T1	2.00 %	Capex			1,3,4
O&M T2	0.70 %	Capex			1,3,4
Power loss T1	1.78 %	Electricity output			1,3,4
Power loss HVDC	1.10 %	Electricity output			1,3,4
Power loss T2	1.89 %	Electricity output			1,3,4

Operation and maintenance costs consist mainly of maintenance of the turbine (38%), port activities (31%), operation, dealing with the primary process (15%), Licence fee (4%), and other costs (12%) (Röckmann et al., 2017). In addition to the direct O&M expenses, we need to consider the loss of revenue in times of maintenance or other activities resulting in the turbine being out of service.

The operation and maintenance expenses are expected to be NOK0.1322/kWh, in addition to 4.35% of losses in revenue due to expected and unexpected maintenance of wind turbines. The estimation is based on a 400 MW wind farm with 50 turbines located 30km from shore in 20m water depth. The O&M cost was NOK0.1499/kWh, in addition to a loss rate of revenue at 5.2%. We expect the O&M cost to decrease based on economies of scale benefits. The cost of maintenance, and the revenue loss, are expected to benefit from a significantly higher-rated power in each turbine. On the other hand, the 1 GW wind farm is located further from the shore, contributing to increased O&M costs (Castellá Xavier., 2017).

However, we calculated a reduction in O&M and loss in revenue costs of respectively 11.81% and 16.74%,based on the the scaling law presented in eq. 3.8.

According to Osmundsen et al. (2021), operational expenses are increasing during the lifetime due to the increased need for maintenance. On the other hand, technological developments and improved experience of maintenance operations can arguably drive operational expenses downwards (Peak-Wind, 2020). Thus, we choose to use a linear Opex throughout the lifetime.

3.2.2.1 OPEX Grid connection

The grid connecting HVDC cable requires operation and maintenance to keep the facility in optimal conditions. The Opex includes revenue loss, fix- and variable- O&M of 2.59% for the seabed cable, 2% for the offshore transformer platform, and 0.7% for the onshore transformer (Larsson, 2021).

3.2.2.2 Power loss

Figure 3.9: Power loss air flow to grid supply

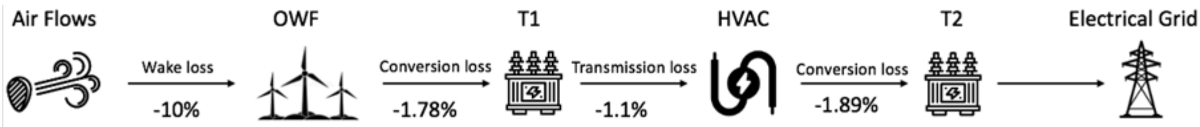


Figure 3.9 presents the loss from wake effects, and in the transmission system. Wake loss from turbulence between surrounding turbines is 10 % of the avialable wind energy (Sikkeland, 2020). The loss in the two transformers is respectively 1.78% and 1.89%, and 1.1% in the HVDC subsea cable calculated from the amount of energy supplied to each equipment (May et al., 2016).

3.2.2.3 Investment timeline

To estimate the project's cost in terms of net present value, we need to estimate the timeline of investments from the early development phase until the wind farm is fully operational. The timeline includes development, planning, pre-construction, and under-construction phase. In total, the estimated timeline from development until the farm is in full operation is eight years (Renewable UK, 2020).

Figure 3.10: Offshore wind farm investment timeline

	Project Development			Planning	Pre-Construction		Construction		Tot (M)
Year	2022	2023	2024	2025	2026	2027	2028	2029	
Project Development									1 436.33
Insurance									38.3
Project management									348.6
Cable									7,399.53
Construction & Installation									10,535.75
Capital Expenditures (M)	478	478	478	82.5	82.5	82.5	9,037.4	9,037.4	19,758.6

In figure 3.10, we present the expected timeline for the development and construction of the wind farm. In the right column, we present the expenses in each project segment. The cost related to each investment phase is presented in the bottom column.

3.2.2.4 Decommissioning

At the end of the technical lifetime of the wind park, mainly three options are available: Life extension, repowering, or decommissioning. Life extension of the wind park includes reconditioning or remanufacturing parts of the turbine to enable further efficient electricity generation. In the repowering option, the electricity generation time is extended by retrofitting. It is expected to include a change of the nacelle and turbine blades (Haugen et al., 2018). Decommissioning of the windfarm means finalizing the operating time of the facility. Thus, uninstall and waste management of the components (Adedipe & Shafiee, 2021).

Limitations in available data restrict the ability to consider the three options without a significant degree of uncertainty. The option choice is considerably far in the future, and increased information is plausible to expect. While the number of finalizations of offshore wind farms is small today, the number of wind farms to choose between the three options in the years to come is high. Therefore, it is for practical purposes, not a decision to make at this point. However, to evaluate the project, we will assume the project to be decommissioned at the end of its lifetime in 2055. Even though Statkraft, with its purchase of 39 wind farms with an operating age varying between 13 and 22 years, expects to repower the turbines. We chose the option with the least economic benefits and the most certain availability (Statkraft, 2021).

According to Kaiser and Snyder's (2012) bottom-up model, several options for decommissioning cost estimations are used in the literature. The capital expenditures of decommissioning a wind farm are 3-4% of the initial Capex. However, the report excluded costs related to regulatory approval and insurance in the estimation. In a study done by Shafiee et al. (2016), including waste management and regulatory approval, the GBP/MW cost was calculated to be £404,739. The cost was based on a 500MW wind farm. However, it is plausible to assume the turbine size in their farm to have a rated power of at least half of the Vestas 15 MW, due to publication in 2016. These scaling effects contradict each other. On one side, the total cost to fit a 1 GW farm requires up-scaling. On the other side, the rated power of each turbine leads to decreasing unit costs of each MW installed. The learning curve effect until 2055 is also assumed to decrease the cost significantly. Thus, we assume a decommissioning cost measured in MW of £202,369.50/MW, following the scaling law presented in eq. 3.8 with a scaling factor of 1.

3.2.3 Hydrogen production Capex

Table 3.8 present the estimated capital expenditures to enable hydrogen production.

Table 3.8: Overview Hydrogen Capex

Name	Unit cost	Unit	Total Cost (m) NOK	Scenario
Offshore Electrolyzer	600	\$/KW	4,998.00	2
Offshore installation costs	41	£/KW	401.80	2
Onshore Electrolyzer	600	\$/KW	4,711.20	3
Onshore installation costs	13.67	£/KW	131.88	3
Stack replacement	210	\$/KW	1,749.30	2,3
Electrolyzer platform	50.00	m\$	425.00	2
Hydrogen pipelines	0.499	m\$/KM	636.23	2
Compression	2545	\$/MW	276.85	2
Seawater reverse osmosis	1580	\$/(m3/d)	56.34	2
On-shore hydrogen storage	36000	\$/MW	35.28	2,3

3.2.3.1 Hydrogen plant sizing

In an offshore setting, as in Scenario 2 with auxiliary energy requirements such as SWRO and a compressor allows for under-sizing of plant size. The energy needed for compression and SWRO is 12.789 MW and 930 KW. A 986 MW electrolyzer is chosen to account for the energy requirements of the external system. As in Scenario 3, the plant size is scaled to accommodate power loss across transformers and cables for an onshore setting. The maximal delivered power would be eq. 3.9

$$Windfarm\ size\ \times\ (1 - Expected\ power\ loss) \tag{3.9}$$

3.2.3.2 Electrolyzer Capex

In their expert citation study, Glenk et al. (2019) find that proton exchange membrane electrolysis has an expected Capex of 600 \$/KW in 2030 for large-scale installations. IEA (2019) has a published range of 650-1500 \$/KW depending on the size of the platform and technological development. This is quoted as a system cost for the PEM system. This figure is expressed as a total figure, including installation costs. Looking into scaling effects of electrolyzer systems, Böhm et al. (2019) find that for systems in 2030, over 100 MW Capex is estimated to be 500 €/KW. A system Capex without installation cost is chosen as 600 \$/KW. Installation costs for an offshore hydrogen platform are estimated using Woznicki et al (2020), where installation costs were quoted to be 41 €/kW for a wind park of significant size (420MW). To estimate the cost of locating the electrolyzer offshore, we calculated the difference between a voltage transformer for electricity placed on- and offshore. Stack replacement of PEM has been estimated to be \$210/kW after the lifetime has been achieved (IRENA 2018). We assume the investment timeline of the Capital expenditures to be two years coinciding with the wind farm's construction.

3.2.3.3 Hydrogen Pipelines

Hydrogen produced must be transported to shore through pipelines. The transmission efficiency of pipelines is 99.8% (Miao et al., 2021). Representing a loss of 0.2% of potential energy through transport. The cost for OM is 7% of Capex. Capex per km of cable is 10% over the cost of natural gas pipelines. According to North Sea Energy (2020), a

1GW wind farm located 150km offshore would need a pipeline diameter of 10 inches and a pressure of 91 Bar. This would equal a Capex per mile of \$0.8m. converting this to per km yields us 0.8/1.609344 = \$0.499/km (Saadi et al. 2018). This gives us a total Capex of \$73.5m for a hydrogen platform located 150 km offshore.

3.2.3.4 Compression

Hydrogen produced by PEM exits the electrolyzer at 30 Bar. The gas needs to be compressed to 91 Bar for a 1 GW wind farm 150 km offshore. This necessitates the electrolyzer to be coupled with a compression device. The idealized gas relationship to calculate power usage of compression of hydrogen gas (Inc Nexant, 2008).

$$P = Q(\frac{1}{24 * 360})\frac{ZTR}{MH_2\eta}\frac{N\gamma}{\gamma - 1}((\frac{P_out}{P_in})^{\frac{\gamma-1}{N\gamma}} - 1) \tag{3.10}$$

Q is the daily flow rate of hydrogen in kg. In a 1GW example, the theoretical maximum is 480 000 kg/day. Z is the hydrogen compressibility factor of 1.03198. N is the number of compressors, assumed to be 2. T is the inlet temperature of hydrogen, utilizing the temperature described above; this is 310.95K. γ is the ratio of specific heats 1.4. MH_2 is molecular mass of hydrogen 2.15 g/mol. η is compressor efficiency ratio (75% is used). R is the universal constant of ideal gas 8.314 J/molK. This leaves us with a compressor size of 11.052 MW. Using a motor efficiency of 95% and oversizing motor by 10%, the total compression capacity needed is 12.789 MW. Below is the National Research Council's relationship to find Capex of compressors (Christensen 2020).

$$CAPEX = 2545(P) \tag{3.11}$$

Giving us a total Capex of \$32.570M. For a 1 GW wind farm operating at full-load, the maximal hydrogen produced is 20 000 kg. The energy needed to compress 1 kg of hydrogen from 30 bar to 91 bar is 12 789kW / 20 000 kg = 0.64 kWh/kg H_2

3.2.3.5 Seawater reverse osmosis

For an electrolyzer located offshore, seawater is needed as an input for hydrogen production. For this to occur, the water needs to be desalinated. Based on the atomic properties of

H_2O, there is a need for 8.92 liters of water to produce 1 kg of hydrogen. Based on a plant size of 980 MW, the largest amount of hydrogen produced in an hour would need to be 986 200 / 50 = 19 720 kg of hydrogen an hour. This requires 175 940 liters of water to be desalinated an hour to meet hydrogen demand at full load. At a full load of 24 hours, this leads us to 4 222 m3/d. The system Capex for reverse seawater osmosis is $1580/(m3/d) (Caldera Breyer, 2017). The total Capex for SWRO is $6 671 572. Energy usage of SWRO is 4-6 kW h/m3 (Al-Karaghouli & Kazmerski, 2013). Considering a usage of 8.92l / kg hydrogen, the energy cost for desalinating water is 0.04 kWh/kg hydrogen. The total system size is to facilitate fast start-up. We install a tank for fresh water to meet quick start-up times. Since no literature is found on start-up times, a start-up time of 15 minutes is assumed. The tank would be filled with water for the first 15 minutes of production necessary for a start-up. A tank of 46.5 m3 would be needed.

3.2.3.6 Auxiliary power system

To facilitate a start-up of hydrogen production of a few seconds, the system needs to be in standby mode. Standby mode consumes 2% of nominal power an hour to keep the electrolyzer pressurized and warm. (Matute et al., 2021). Utilizing a cold start-up time of 3 minutes, we find that the revenue lost when not connected to an auxiliary power source is $628,847 in a low-price scenario. In the base scenario, a revenue loss of $1,131,925, and in a high price scenario, the loss would be $1,653,003. This represents approximately 0.01% of total revenues. To find the potential cost of avoiding cold start losses, battery costs and maintenance must be accounted for. Battery sizing for cold starts is tricky, as the longest time encountered without power into the electrolyzer is 68 hours. The average is 7 hours. A battery of 7 hours at 2% of 980MW would be 137,2MW. According to NREL, the Capex of lithium-ion batteries would be $1,682/kW, totaling $230,770,400 in 2030, far exceeding the loss of cold starts. This is before accounting for the costs of Opex and alternative costs for electricity of battery charging during energy production. For our analysis, we utilize cold start-ups.

3.2.3.7 Hydrogen delivery system

In an offshore production system, two possible scenarios are imaginable when hydrogen arrives onshore. Hydrogen is connected to an industrial process where hydrogen is an input factor in production, or hydrogen is transported. For hydrogen to be transported, a short-term storage solution is needed. We assume 12 total load hours of storage capacity to be transported by truck/ship twice a day. As calculated in 3.5.5, hourly full load production is 20 000 kg hydrogen. Storage for 240 000 kg is needed. In their analysis, S. McDonagh et al. (2020) use a Capex of €6000/MW per full load hour. This leads to a hydrogen storage solution Capex of $82 202 400.

3.2.3.8 Electrolyzer placement

Hydrogen can be produced both onshore and offshore. To find the best solution, we will have to evaluate the costs and benefits of the two different options. The advantage of producing the hydrogen offshore is mitigating losses in the transmission process of energy from the wind farm into the mainland. On the other hand, the O&M will be simplified by locating the electrolyzer onshore. To calculate the NPV of the two different options, we first sampled and compared the unique costs for each option, presented in figure 3.11.

Figure 3.11: Costs asscociated with different placements

CAPEX

Component	Cost M/NOK
Onshore	
Offshore transformer	2 392,50
HVDC-cable	1 815,00
Onshore transformer	1 828,60
Sum	6 036,10
Offshore	
SWRO	59,50
Compressor	325,70
Hydrogen pipline	212,08
Offshore platform	563,90
Sum	1 161,18

OPEX

Component	Cost M/NOK
Onshore	
T1, T2, cable	107,66
Sum	107,66
Offshore	
Compressor	9,77
Pipeline	1,75
SWRO	1,79
Sum	13,30

Power loss

Component	Loss
Onshore	
Transmission	4,70 %
Offshore	
Pipeline loss	0,20 %

Further, we calculated the differences in power loss from transporting the energy from the wind farm to shore. The loss in power from the T1, HVDC-cable, and T2 is calculated to be 4.70%, while transmission of hydrogen is 0.2%. We multiplied the difference in loss factor by the yearly gross energy generated offshore to estimate the value. Lastly, the energy loss is multiplied with the three different hydrogen prices, adjusted for the amount of electricity needed to produce 1kg of hydrogen. In the scenario of only hydrogen production, we choose to locate the electrolyzer offshore. However, to locate the electrolyzer offshore for scenario 3 would entail building both subsea electricity cable and hydrogen pipelines.

This is not economically sensible. To invest in additional infrastructure for electricity and hydrogen transmission from the offshore platform, involving a total cost of NOK1.37 billion. This is above the alternative benefit of omitting a loss of 4.5% for the total hydrogen produced. In scenario 3, with an onshore electrolyzer, we include a water price of 7.83 NOK/m^3 (Kristiansand Kommune, 2021).

3.2.3.9 Hydrogen Production Opex

The operational expenses to produce hydrogen is presented in the table 3.9. Most of the variables are calculated as a percentage of the capital expenditures or in relation to the amount of hydrogen extracted.

Table 3.9: Overview Hydrogen Opex

Name	Unit cost	Unit	Yearly cost	Relevant scenario
Onshore electrolyzer	2 %	Capex	98.43	3
Offshore electrolyzer	3 %	Capex	149.94	2
Electrolyzer hydrogen production	50	kWh/kg H2		2,3
Compression	3 %	Capex	8.31	2
Hydrogen pipelines	7 %	Capex	14.85	2
Seawater reverse osmosis	3 %	Capex	1.69	2
On-shore hydrogen storage	3 %	Capex	1.06	2,3
Electrolyzer efficiency loss	2 %	kWh/kg H2		2,3

IRENA (2018) quotes operations and maintenance to be 2% of Capex costs. In their review of water electrolysis systems Buttler et al (2018) state a maintenance cost of 3-5% of Capex of the current state-of-the-art systems. They also state that an increase in the size of the system will decrease Opex costs as a factor of Capex, so scaling the electrolyzer considerably from current sizing will decrease this number. To account for higher expected maintenance costs, Opex as a percent of Capex is chosen to be 3%. For an onshore electrolyzer a value of 2% of chosen as the change of climate the electrolyzer is stored in is expected to drive OM costs down.

The energy needed to produce 1 kg of hydrogen using a PEM is expected in 2025 to be 52kWh/kg. (IRENA 2018). IEA (2018) predicts a 52.8-49 kWh/kg range in 2030. The energy needed to produce 1 kg of hydrogen is chosen as 50kWh.

Buttler & Spliethoff (2018) finds that lifetime of PEMs is in the range of 60,000 – 100,000 hours. IEA (2019) expects a stack lifetime of 60,000-90,000 hours in 2030. Buttler & Spliethoff (2018) report an annual efficiency loss of 0.5 – 2.5% per year, assuming a full operational schedule. 2% is chosen to account for potential extra efficiency loss due to cold starts. The efficiency loss is reset when the electrolyzer stack is replaced.

For other factors not explicitly stated above, 3% Opex costs of Capex are chosen.

The minimum electrical load of the electrolyzer is 5% by Siemens and Lettenmeier (2020). Thus, a wind speed of 3.94m/s is required to reach the minimum load. This is accounted for scenarios producing hydrogen.

3.3 Energy storage

Table 3.10: Overview Energy storage

Battery solution	Price KWh	Price KW	Total (M NOK)	Round-trip	Degradation
Lithium-ion	1,700	6,800	680	90 %	2.900% p.a
Pumped hydro storage		22,694	4,538	80 %	1.825% p.a

3.3.0.1 Battery Capex

Lithium-ion is attractive in vehicles and for use in portable communication devices. Significantly, the savings capacity, cycle stability, and high energy density make it preferred to other solutions (Rashidi, 2022). Nonetheless, the materials used for construction are both precious and face bottlenecks in production or extraction. The development in costs during the last decade has been significant. Since 2014, the cost has decreased from \$700/kWh to \$300 in 2020 (Killer et al., 2020). According to Cole et al. (2021), the cost of a lithium-ion storage system could decrease to below \$200 kWh in 2030. From a battery energy storage system (BESS), the energy output decreases compared to the inflow of energy. The roundtrip efficiency is 90%. In addition, the battery's ability to store is reduced during the operating lifetime with degradation of 2.59% p.a (Lazard, 2020).

In the arbitrage switching scenario, we will use a 100MW battery with a daily use of four hours. To calculate the investment cost of constructing the battery, we first multiply the price denoted in KWh with the hours of daily use. Then we find the price of the facility by adjusting for facility size.

For operations, we assume one cycle each day over the 20-year lifetime. To increase the cycle each day to two or three, the battery's lifetime would decrease.

3.3.0.2 PHS Capex

Cost of developing a storage system using hydro reservoir includes two reservoirs, tunnels for water transportation and a powerhouse. According to Black Veatch (2012), the capital expenditures variates between NOK34,043.68 kW and NOK11,345.09 kW, due to differences in the natural geographical conditions. Future developments will be marginal declining from further utilization of economies of scale from increased reservoir size (Miller, 2020). In the valuation analysis, we will use a 200 MW sized reservoir, similar to the Duge facility located in the NO2 aera in Norway (Pitorac, 2020). The cost is calculated form the mean of estimation and adjusted for the projected size.

Hydro power storage has a decreased output of energy compared to energy use for water transportation. In total the roundtrip efficiency is between 80% (Gallo, 2016). Normally, the ability discharge ability is ten hours, due to restrictions in the system generating power. In case of the charging time, is it determined form the tunnels size, and capacity of the powerhouse (EASE, 2016).

3.3.0.3 Timeline PHS Capex

According to a study published by the U.S Department of Energy, the development and construction of a PHS facility will take approximately eight years to complete. The first four years involve accessing the required licenses and approval for constructing and operating the facility. The construction work starts at the beginning of year five and ends in year eight when the facility is ready to operate at full capacity (Bishop, 2021). The total capital expenditures will be distributed with 13% over the first four years (e.i 3.25%/yearly) and 87% equally distributed over the last four years of construction (Bishop et al., 2020).

3.3.0.4 Battery Opex

For the variable and fixed costs of operating and maintenance (VOM & FOM) we set VOM equal to zero because of our assumption that the battery will not need any significant maintenance during the life cycle. FOM is set equal to 2.5% of the capital expenditure of producing the battery (Cole et al., 2021). The fixed operation and maintenance costs ensure the facilities' condition and an efficient charge/discharge process.

3.3.0.5 PHS Opex

The pumped hydropower plants operating and maintenance expenses are calculated following equation 3.12 (Black Veatch, 2012).

$$34,740 * p^{0.32} * AE^{0.33} \tag{3.12}$$

Where, P: Plant capacity (MW) AE: annual energy throughput (MWh)

3.4 Financial estimates

3.4.1 Currency exchange rates

The currency exchange rate chosen for converting foreign currency into NOK is essential for the NPV analysis.

We have some models and theories of different variables affecting the Norwegian currency in different directions from empirical studies. Two of the most commonly used methods are the purchasing power parity (PPP) and the interest rate parity (IRP). However, none of the theories consistently explain historical developments (Juselius, 1995). In addition to PPP and IRP, one standard forecasting method is mean reversion. The hypothesis is built on stationarity in currency development, with transitory fluctuations. However, empirical studies provide a lack of evidence of the method consistently outperforming random walk in out of sample tests (Jorion & Sweeney, 1996). However, the best model to predict development in currency exchange rates in the mid-and long-term is the random walk model (Meese & Rogoff, 1981).

In this thesis, we will use the exchange rate forecast used by Equinor from 2024 going forward of NOK|$ 8.5, NOK|€ 10.0, and NOK|£ 11.0 (Equinor, 2021).

3.5 Cost of capital

To be able to estimate the net present value of the future cash flows of the project, we determine the appropriate discount rate. The discount rate represents the alternative return for an investor investing in another project with similar risk. The cost of capital consists of three components: the project's capital structure, cost of equity, and the after-tax cost of debt (McKinsey & Company Inc. et al., 2020)

3.5.1 Capital structure

The capital structure of a firm or a project is essential to measure the risk level of the capital invested either by the equity- or debtholders. In a famous article, Modigliani Miller stated the irrelevance of choosing between debt and equity in a frictionless world (Modigliani & Miller, 1958). However, a capital structure including debt benefits from utilizing the tax shield and decreases the agency cost. On the other hand, debt increases the financial distress cost (Cordes & Sheffrin, 1983). According to Damodaran (2021), the average debt-to-equity ratio within the renewable energy sector is 64.06%. Therefore, calculating the present value of the project using a similar financing structure seems reasonable. On the other hand, the implications of the financial structure should not be the marginal factor determining the investment decision. Therefore, we assume all-equity financing. This implies cost of capital equals the cost of equity, excluding requirements of the after-tax cost of debt calculation.

3.5.2 Cost of equity

The rate of return required by equity investors is usually hard to estimate accurately. The theory is to use the expected market return and adjust for the risk level of the project or corporation. The most frequently used technique is the capital asset pricing model (CAPM). One method to calculate the expected market return is to work backward from the consensus financial forecast of future income and growth to find the equity cost which defends the stock prices observed in the market. Another is to base the estimation on historical performance by the stock market in relation to a risk-free asset. Both techniques have some advantages and disadvantages. The historical approach does not consider the fast development of society and changes in monetary policy. On the other hand, the consensus method is hard to pursue and builds on analyst estimates. We will use the CAPM technique presented in 3.13

$$r_e = r_f + \beta_e(r_{mkt} - r_f) \tag{3.13}$$

Equity risk premium (ERP) is discussed broadly within the world of finance. However, a universal agreement of the premium value is not existing. Damodaran calculated the ERP in the US market to be 7.9% using the arithmetic mean between US bills relative to the market portfolio (Damodaran, 2021). In a study based on the Norwegian market, the equity risk premium was estimated to be 7.08% (Norges Bank, 2016). The premium was calculated by the difference between stocks and bills using the arithmetic mean in the time period of 1900-2014. According to Dimson et al. (2002), it is beneficial to use arithmetic means for future decision-making rather than geometric.

3.5.3 Equity Beta

The most common way to calculate the systematic risk for public traded companies is to estimate the beta by regressing relevant stock returns on the market portfolio proxy. The best way to estimate the beta is to use monthly data from the last five years. It mitigates noise for daily fluctuations and includes an acceptable number of data points to make a valid estimation (McKinsey & Company Inc. et al., 2020). To increase the knowledge about systematic risk, a common technique is to estimate an industry beta by calculating the systematic risk of comparable investments. The level of similarities in operating industry, size, etc., is beneficial when choosing comparable companies. The most crucial characteristic is for the firm to be operating within the offshore wind or renewable energy industry. For project evaluation, the importance of the attributes like the company's size, etc. decreases. However, a diversified mix of companies could avoid a biased industry beta. The comparable companies we will use for industry beta determination are Magnora ASA and Ørsted A/S. Both firms operate within the offshore wind industry with other renewable energy sources. Ørsted A/S is a large Danish company with a market capitalization of 350 billion DKK, concentrating on making the world fully supplied by green energy solutions (Orsted, 2021a). In 2020 they had a debt-to-capital ratio of approximately 50% (Orsted, 2021b). On the other hand, Magnora ASA is a small-cap Norwegian listed company. Their initial focus was offshore wind, but solar is also a significant part of Magnoras product portfolio (Magnora, 2021b). Their market capitalization is slightly above NOK1 billion, with a debt-to-equity ratio of 2.21% (Magnora, 2021a). In combination, we believe the two companies to be suitable comparable companies. We compared the returns adjusted for stock splits, dividends, and currency from the two stocks according to the MSCI world index to estimate the industry beta(Yahoo Finance, 2021). The MSCI index is well-diversified and suited to capture the market development for beta estimation. The Industry beta was calculated in three steps:

1. Calculated the levered beta

$$\beta_l = \frac{Cov(MSCI, Company)}{Var(MSCI)} \tag{3.14}$$

2. Unlevered the beta

$$\beta_u = \frac{\beta_l}{(1 + (1 - t_c) * \frac{D}{E})} \tag{3.15}$$

3. Average of the beta for Orsted and Magnora

$$\beta_i = 0.5 \ * \ \beta_{Orsted} + \ 0.5 \ * \ \beta_{MGN} \tag{3.16}$$

3.5.4 Risk free rate

The risk-free rate is usually based on the 10y U.S. Treasury. The United States of America is known to be risk-free, with close to zero liquidity risk premium. To capture the risk-free rate for a project operating in Norway, we would need to adjust for the development in currency rates. Thus, adjusting the 10y U.S. treasury would include some currency risk. Therefore, we would base the risk-free rate on the 10y Norwegian government bond.

The reason for using the 10y instead of the 30y is based on the ability to observe the actual long-term risk-free rate without too much time premium. The 27. November 2021, the 10y Norwegian government bond is traded with a yield of 1.61% (Trading Economics, 2021).

3.5.5 Inflation adjustment

In the following valuation analysis of different scenarios, the cost structure is denoted in cost levels based on the purchasing power of 2020. Thus, we will adjust the weighted average cost of capital by the implied inflation expectation in the market. The expected inflation rate is derived from the difference between the 10-year U.S. Treasury and the 10-year TIPS (Quote-US10YTIP, 2021) (Quote-US10Y, 2021) to capture the true inflation expectations by the market. As of 14. November 2021, the difference is 2.73%. To calculate the inflation-adjusted required rate of return, we subtract the inflation from the first part of eq. 3.13.

$$\mu_{real} = r_f - infl + \beta(r_{mkt} - r_f) \tag{3.17}$$

Table 3.11: Inputs for Discount-rate calculation

β	0.764
r_f	1.61%
Inflation	2.73%
r_{mkt}	8.69%
$\mu_{Nominal}$	7.016%
μ_{Real}	4.29%

4 Methodology

4.1 Revenue calculations

In the following section we calculate revenues for all scenarios. As a commonality, all scenarios are powered by the wind farm. The energy produced by the wind farm is calculated by equations outlined in Appendix B.

$$E_t^{Output} \tag{4.1}$$

Energy output was based on a single year of wind production detailed in 3.1.1

$$P_t^{El} \tag{4.2}$$

For scenarios 1, 2, and 4 the short-term deviations in electricity prices were averaged out to create a expected year for price fluctuations. For scenario 3 seven short-term deviation scenarios were set up detailed in section 3.1.2.4

The reason for constructing standard years as detailed above is for the variability of the data not to affect the net present value of the scenarios. When we attempt to distribute variability evenly, this should not affect net present value positively or negatively.

4.1.1 Scenario 1

The calculation of electricity transmitted to shore is calculated by deducting power losses along the transmission process presented in eq. 4.3.

$$E_t^{Generated} = E_t^{Output} * (1 - T1_{loss}) * (1 - HVAC_{loss}) * (1 - T2_{loss}) * (1 - Revenue_{loss}) \tag{4.3}$$

From energy transmitted to the grid, we calculate the revenue by multiplying the amount of electricity transmitted with the price in each specific hour following eq. 4.4.

$$R_t^{Electricity} = (P_t^{El} * E_t^{Generated}) \tag{4.4}$$

The EBIT is calculated following eq. 4.5.

$$EBIT_t^{Electricity} = (R_t^{Electricity} - C_t^{Opex} - C_t^{Depreciation}) \tag{4.5}$$

4.1.2 Scenario 2

The hydrogen transported to shore for direct sale is calculated from the energy output multiplied with the conversion ratio of electricity needed for one kg of hydrogen production. Furthermore, the hydrogen transported to shore for sale is calculated by the hydrogen output from the electrolyzer, minus pipeline loss. This is presented in eq. 4.6.

$$E_t^{Output} * \frac{kg\ H_2}{kWh} * (1 - Pipeline_{loss}) = H_{kg} \tag{4.6}$$

From the output of hydrogen, the revenue is calculated from the amount supplied multiplied with the price, presented in eq 4.7.

$$R_t^{Hydrogen} = (P_t^{Hydrogen} * H_{kg}) \tag{4.7}$$

The EBIT is calcluated from eq. 4.8

$$EBIT_t^{Hydrogen} = (R_t^{Hydrogen} - C_t^{Opex} - C_t^{Depreciation}) \tag{4.8}$$

4.1.3 Scenario 3

For a production process of switching between hydrogen and sale of electricity to the electrical grid an assumption of future prices must be taken. As outlined in chapter 2.2.2 currently the only viable market for large scale sale of electricity is the day-ahead market. There are two ways to solve this: (1) assume that we have perfect foresight into the next day electricity prices when submitting bids or (2) estimate the next day price based on characteristics and plan production based on the expected price. McDonagh et al (2020) assumes perfect foresight in electricity prices. We will use an estimation model for future prices of power based on multiple linear regression analysis.

To build the deterministic multiple linear regression we use the seasonality examined in chapter 3.1.2.1 to forecast next-day prices into the future. The model is based on observed historical data and returns an adjusted-R^2 of 0.875. The estimated parameters are based on the el-spot prices observed in 2015-2021. Appendix C includes the summary statistics for the multiple regression.

$$Future\,price \;=\; \beta_0 + \beta_1 Hour + \beta_2 Season + \beta_3 Weekday + \beta_4 Avg\,price_{t-1} + u_t \quad (4.9)$$

When choosing to produce hydrogen or sell electricity to the grid we want to maximize economic value of the production. To accommodate this, we as in McDonagh et al (2020) find a set point for hydrogen production where a revenue maximizing operator would be indifferent between producing hydrogen and selling electricity to the grid.

$$Set\ point\ hydrogen\ production \;=\; \frac{Price\ H_2}{kWh/kg\ H_2} \quad (4.10)$$

Energy is sold as electricity if the expected price of electricity is above the set point, and converted to hydrogen if it is below.
In this scenario we created 7 different years as detailed in section 3.1.2.4. For each of the seven price scenarios we calculate the revenue. The ability to switch production creates two potential revenue sources as presented in 4.11 and 4.12.

$$R^{Electricity}_{Switching} = (P^{El}_t * E^{Generated}_t) \quad (4.11)$$

$$R^{Hydrogen}_{Switching} = (P^{Hydrogen}_t * H_{kg}) \quad (4.12)$$

By combining eq. 4.11 and 4.12 the total revenue of the switching option is calculated in 4.13.

$$R^{Switching}_t = R^{Switching}_{Hydrogen} + R^{Switching}_{Electricity} \quad (4.13)$$

The seven different price scenarios are weighted equally to create the expected revenue per year for scenario 3.

The EBIT is calculated following eq. 4.14.

$$EBIT_t^{Switching} = (R_t^{Switching} - C_t^{Opex} - C_t^{Depreciation}) \tag{4.14}$$

4.1.4 Scenario 4

To develop a strategy deploying energy storage to maximize revenue, the seasonality discussed in chapter 3.1.2.1 is considered. Energy prices follow consumption, thus leading to expected peaks and troughs throughout the day.

The electricity is stored in batteries onshore in trough periods before sold to the energy grid in peak hours. There are three states of revenue when batteries are coupled with offshore wind farms.

$$R_{Normal}^{Battey} = E_t^{Generated} * P_t^{El} \tag{4.15}$$

$$R_{Trough}^{Battey} = (E_t^{Gen} - E_t^{Charged}) * P_t^{El} \tag{4.16}$$

$$R_{Peak}^{Battey} = R_{Normal}^{Battey} + (E_t^{Charged} * P_t^{El} * Efficency_{Roundtrip}) \tag{4.17}$$

To find the addition revenue batteries bring compared to a wind park without electricity storage the calculation in 4.18 is made.

$$R_t^{Incremental} = R_t^{Battery} - R_t^{Electricity} \tag{4.18}$$

The EBIT is calcluated from 4.19.

$$EBIT_t^{Incremental} = (R_t^{Incremental} - C_t^{Opex} - C_t^{Depreciation}) \tag{4.19}$$

4.2 Discounted cash flow

The discounted cash flow model is a technique to value a project or a company. The approach discounts the expected future cash flows with a discount rate to find the net present value. Within the model, there are different techniques to apply in various situations, mostly depending on the capital structure. As mentioned before, we assume an all-equity financing. Thus, the differences between the WACC, APV or FCFE method is mitigated.

First, we forecast the free cash flow (FCF) during the project's lifetime. The inputs in the model are based on calculations from chapter 3. From the inputs we follow eq. 4.20, to find the FCF.

$$EBIT * (1 - \tau_c) + dep - \Delta NWC - CAPEX = FCF \tag{4.20}$$

Second, we use the cost of capital presented in chapter 3.5 to discount the cash flows following eq. 4.21.

$$\sum_{t=1..n} \frac{FCF_t}{(1 + \mu_{Real})^t} \tag{4.21}$$

The free cash flow calculations included some important accounting rules in the depreciation and payable taxes.

Depreciation

In Norway, a special law determines the distribution of expenditures related to acquiring assets for operating a wind farm. The law is stated in the tax law § 14-51 "Avskrivning av vindkraftverk" (Skatteloven, 1999). The capital expenditures should be equally distributed over the five following years, according to the paragraph. However, the validity of the law is expiring at the end of 2021. The design of the law enables utilization of the beneficial depreciation technique if the project is in development at the end of 2021. For the relevance of the results to exceed the end of 2021, we will therefore use a depreciation rate of 20% (sktl. §14-43d). A reversion of this law means future wind farms will be disadvantaged compared to previous wind farm installations.

Deferred tax benefit

According to KPMG (2019), a company can delay a tax benefit to equalize future payable taxes. The Norwegian tax attorney allows tax credit to be deferred when it is plausible to expect the tax credit to be equalized for future taxations relief. For practical purposes, it is possible to calculate the cumulative tax benefits through an investment phase and reduce the potential payable taxes in the first operating years of the facility. Thus, in the first years of operating the wind farm, the actual tax will be canceled out against the cumulative deferred tax benefit. As Cashflows occurring closer to starting date are worth more than cashflows occurring later, the ability to capture deferred tax benefits impacts the NPV of the project heavily.

5 Analysis

In the following chapter, we provide the results of each scenario following the discounted cash flow technique described in section 4.2. Furthermore, we will present a sensitivity analysis for the most critical variables. Due to a high degree of uncertainty in all four scenarios, we believe a nuanced presentation of the results increases the validity. We use two profitability metrics to evaluate each scenario: NPV and IRR_{Real}. To fully be able to compared the results to other related investments possibilities, we will also present the nominal internal rate of return. To calculate the rate nominally, we reverse the process of inflation adjustment described in chapter 3.5.5 by adding the inflation of 2.73% to the IRR_{Real}.

The sensitivity analysis looks into four variables: the cost of capital, capital expenditures, operational expenses, and revenues. The uncertainty in forecast estimation of the variables one, two, and three decades into the future is vast. To use a sensitivity approach regarding the four most substantial variables, we believe in increasing the understanding of the plausible outcome of the scenarios. All four variables are evaluated in an interval of ±10% compared to the base case. The threshold for breakeven is highly relevant and will be further discussed. For breakeven calculations, we adjust the variable discussed to find the threshold where NPV is equal to 0.

5.1 Scenario 1

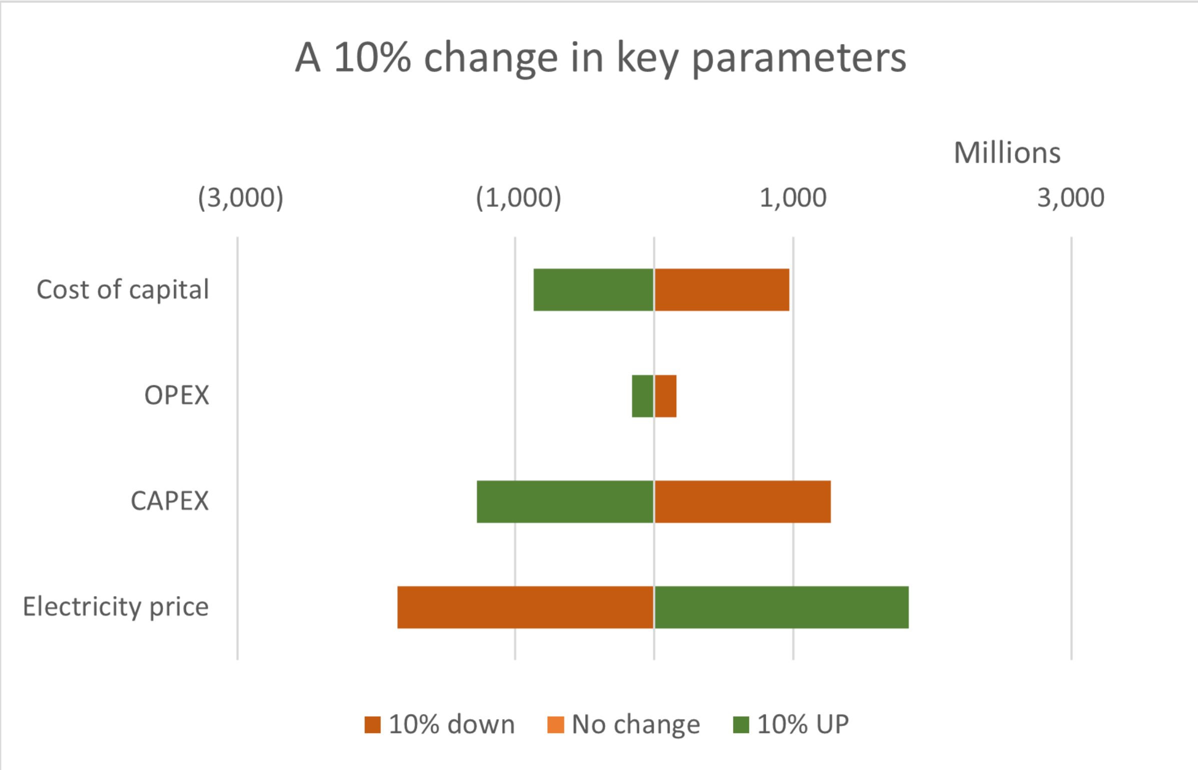
In the first scenario, we investigate direct electricity sale into the Norwegian electrical grid network. The first operational revenues occur in 2030 and ends in 2055.

Table 5.1: Cashflows overview Scenario 1. Figure are displayed in million NOK.

Year	Revenue	OPEX	Planning/ Dev.	Depreciation	EBIT	Tax paid	EAT	CAPEX	Depeciation	Free cash flow	Net present value
2022	-	-	478.0	-	- 478.0	-	- 478.0	-	-	- 478.0	- 458.4
2023	-	-	478.0	-	- 478.0	-	- 478.0	-	-	- 478.0	- 439.5
2024	-	-	478.0	-	- 478.0	-	- 478.0	-	-	- 478.0	- 421.4
2025	-	-	82.5	-	- 82.5	-	- 82.5	-	-	- 82.5	- 69.7
2026	-	-	82.5	-	- 82.5	-	- 82.5	-	-	- 82.5	- 66.9
2027	-	-	82.5	-	- 82.5	-	- 82.5	-	-	- 82.5	- 64.1
2028	-	-	69.7	1,793.5	- 1,863.2	-	- 1,863.2	8,967.3	1,793.5	- 9,037.1	- 6,736.5
2029	-	-	69.7	3,228.2	- 3,298.0	-	- 3,298.0	8,967.3	3,228.2	- 9,037.1	- 6,459.6
2030	2,165.8	179.6	-	2,582.6	- 596.4	-	- 596.4	-	2,582.6	1,986.2	1,361.4
2031	2,165.6	179.6	-	2,066.1	- 80.1	-	- 80.1	-	2,066.1	1,986.0	1,305.3
2032	2,171.7	179.7	-	1,652.9	339.1	-	339.1	-	1,652.9	1,992.0	1,255.4
2033	2,163.1	179.6	-	1,322.3	661.1	-	661.1	-	1,322.3	1,983.4	1,198.6
2034	2,163.3	179.6	-	1,057.8	925.8	-	925.8	-	1,057.8	1,983.7	1,149.5
2035	2,033.6	179.6	-	846.3	1,007.7	-	1,007.7	-	846.3	1,854.0	1,030.2
2036	2,036.6	179.7	-	677.0	1,180.0	-	1,180.0	-	677.0	1,857.0	989.4
2037	2,031.0	179.6	-	541.6	1,309.7	-	1,309.7	-	541.6	1,851.3	945.9
2038	2,030.8	179.6	-	433.3	1,417.9	-	1,417.9	-	433.3	1,851.2	906.9
2039	2,031.1	179.6	-	346.6	1,504.9	- 182.0	1,322.9	-	346.6	1,669.5	784.3
2040	2,039.7	179.7	-	277.3	1,582.7	- 348.2	1,234.5	-	277.3	1,511.8	681.0
2041	2,033.0	179.6	-	221.8	1,631.6	- 358.9	1,272.6	-	221.8	1,494.5	645.5
2042	2,033.0	179.6	-	177.5	1,675.9	- 368.7	1,307.2	-	177.5	1,484.7	615.0
2043	2,033.2	179.6	-	142.0	1,711.6	- 376.5	1,335.0	-	142.0	1,477.0	586.6
2044	2,040.8	179.7	-	113.6	1,747.6	- 384.5	1,363.1	-	113.6	1,476.7	562.4
2045	2,036.4	179.6	-	90.9	1,765.9	- 388.5	1,377.4	-	90.9	1,468.3	536.2
2046	2,036.7	179.6	-	72.7	1,784.4	- 392.6	1,391.8	-	72.7	1,464.5	512.9
2047	2,036.7	179.6	-	58.2	1,798.9	- 395.8	1,403.1	-	58.2	1,461.3	490.7
2048	2,046.4	179.6	-	46.5	1,820.2	- 400.4	1,419.8	-	46.5	1,466.3	472.1
2049	2,042.6	179.6	-	37.2	1,825.8	- 401.7	1,424.1	-	37.2	1,461.3	451.2
2050	2,042.8	179.6	-	29.8	1,833.4	- 403.3	1,430.0	-	29.8	1,459.8	432.2
2051	2,042.6	179.6	-	23.8	1,839.2	- 404.6	1,434.6	-	23.8	1,458.4	414.0
2052	2,049.6	179.7	-	19.1	1,850.9	- 407.2	1,443.7	-	19.1	1,462.8	398.2
2053	2,043.9	179.6	-	15.2	1,849.0	- 406.8	1,442.2	-	15.2	1,457.5	380.5
2054	2,044.0	179.6	-	12.2	1,852.2	- 407.5	1,444.7	-	12.2	1,456.9	364.7
2055	2,043.9	179.6	-	9.8	1,854.5	- 408.0	1,446.5	2,226.1	9.8	- 769.8	- 184.8

The net present value calculated is 3,569m NOK. Furthermore, the IRR_{Real} in the base case is 6.48%, which implies a nominal internal rate of return of 9.21%. We can observe a wide range of yearly free cash flows in the right column, based on changes in expected electricity prices, and accounting adjustments. Taxes first occur in 2038 due to the ability to defer taxes.

Figure 5.1: Sensitivity analysis Scenario 1



The net present value varies from 4,838m to 2,290m with a change of 10% in the capital expenditures. Expenditures in both investment- and decommissioning phase significantly contribute to the total cost of direct electricity sale. The breakeven threshold for capital expenditures is found to be a 27.7% increase. One major challenge to estimate the wind farm cost is the calculation of turbine, foundation, and transmission costs, with uncertainties in technological development, learning curve, and utilization of economies of scale. The breakeven discount rate is 9.21%, as indicated by the IRR presented above. Compared to Damodaran´s average cost of equity for the renewable energy sector of 5.93%, we used a slightly higher with 7.016% pre-inflation adjustment (Damodaran, 2021). However, the change in interest rates, a slight miss calculated beta, or equity risk premium is plausible. Thus, understanding the effects of the variation in the parameter seems beneficial. From the figure 5.1, we see a significant change in NPV by a 10% change in the discount rate both to the up- and down-side. The operational expenses in the base case are calculated to be 23.1% of the total Capex, both denoted in 2021 prices. In the literature, the discounted Opex is usually calculated to be in the area of 20-25% of Capex (Wind peak, 2021) (Osmundsen,2021). However, the importance of operational expenditures in literature is often neglected, and calculated directly as a percentage of capital expenditures, independent of size and distance to shore. The operational expenses need to increase 3.23x for the project to break-even.

The revenue stream is expected to be the most influential parameter for the NPV. The net present value varies from 5,403m to 1,724m with a change of 10% in the electricity prices. In the electricity price estimation, uncertainties regarding future development in volatility and price levels based on the increased market integration towards Europe and the impact of more renewable energy sources are debatable. The breakeven is an average reduction of price by 19.3% throughout the lifetime of the windfarm.

5.2 Scenario 2

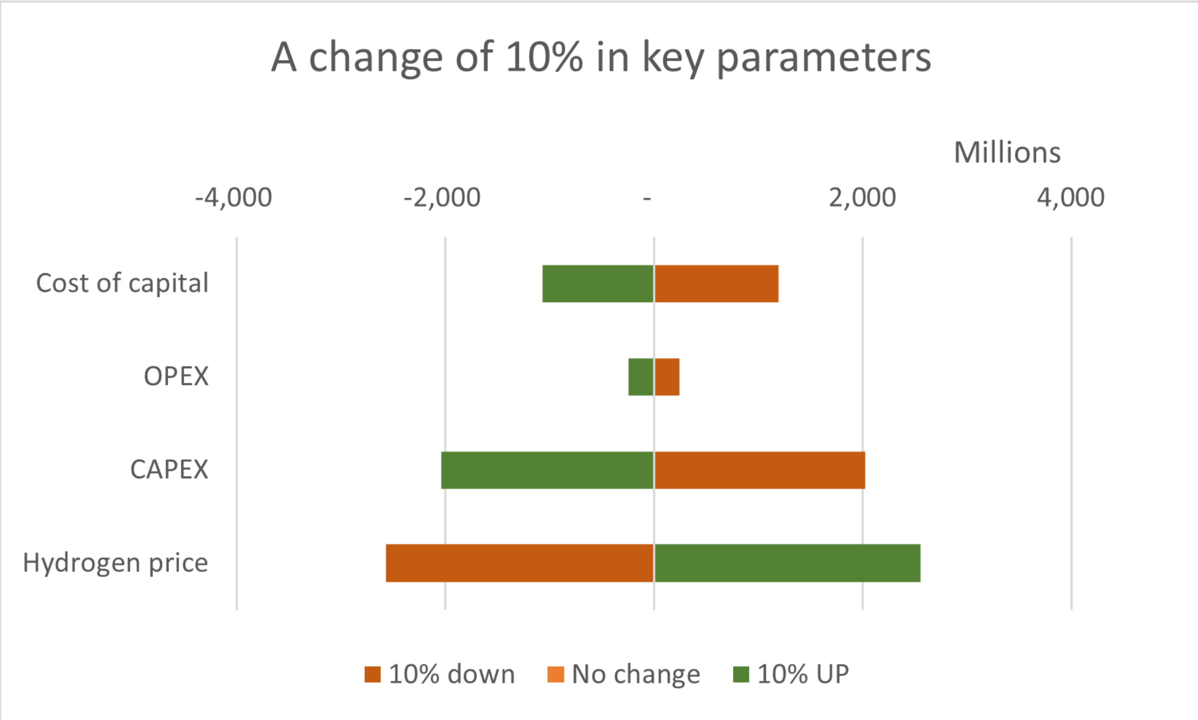
In scenario two, we investigate the profitability of only producing hydrogen. The electrolyzer facility is placed offshore.

Table 5.2: Cashflows overview Scenario 2. Figure are displayed in million NOK.

Year	**Revenue**	**OPEX**	**Planning/ Dev.**	**Depreciation**	**EBIT**	**Taxes**	**EAT**	**CAPEX**	**Depreciation**	**Free cash flow**	**Net present value**
2022	-	-	478.0	-	- 478.0	-	- 478.0	-	-	- 478.0	- 478.0
2023	-	-	478.0	-	- 478.0	-	- 478.0	-	-	- 478.0	- 458.4
2024	-	-	478.0	-	- 478.0	-	- 478.0	-	-	- 478.0	- 439.5
2025	-	-	82.5	-	- 82.5	-	- 82.5	-	-	- 82.5	- 72.7
2026	-	-	82.5	-	- 82.5	-	- 82.5	-	-	- 82.5	- 69.7
2027	-	-	82.5	-	- 82.5	-	- 82.5	-	-	- 82.5	- 66.9
2028	-	-	69.7	2,540.3	- 2,610.0	-	- 2,610.0	12,701.6	2,540.3	- 12,771.3	- 9,928.2
2029	-	-	69.7	4,572.6	- 4,642.3	-	- 4,642.3	12,701.6	4,572.6	- 12,771.3	- 9,520.1
2030	3,101.2	249.5	-	3,658.1	- 806.4	-	- 806.4	-	3,658.1	2,851.7	1,954.8
2031	2,925.9	249.5	-	2,926.5	- 250.0	-	- 250.0	-	2,926.5	2,676.4	1,834.0
2032	2,961.1	249.5	-	2,341.2	370.5	-	370.5	-	2,341.2	2,711.6	1,729.8
2033	2,832.4	249.5	-	1,872.9	710.0	-	710.0	-	1,872.9	2,582.9	1,614.5
2034	2,810.4	249.5	-	1,498.3	1,062.6	-	1,062.6	-	1,498.3	2,560.9	1,514.9
2035	2,812.6	249.5	-	1,198.7	1,364.4	-	1,364.4	-	1,198.7	2,563.1	1,420.9
2036	2,656.3	249.5	-	958.9	1,447.8	-	1,447.8	-	958.9	2,406.8	1,340.0
2037	2,670.2	249.5	-	767.2	1,653.5	-	1,653.5	-	767.2	2,420.7	1,250.4
2038	2,570.7	249.5	-	613.7	1,707.4	-	1,707.4	-	613.7	2,321.2	1,172.8
2039	2,546.2	249.5	-	491.0	1,805.8	- 0.2	1,805.6	-	491.0	2,296.6	1,100.2
2040	2,559.6	249.5	-	392.8	1,917.3	- 418.9	1,498.4	-	392.8	1,891.2	890.6
2041	2,976.8	249.5	-	535.9	2,191.3	- 479.3	1,712.0	1,760.0	535.9	488.0	121.3
2042	3,001.6	249.5	-	180.2	2,571.9	- 562.9	2,008.9	-	180.2	2,189.2	949.5
2043	2,892.2	249.5	-	144.6	2,498.0	- 546.7	1,951.3	-	144.6	2,095.9	882.6
2044	2,887.3	249.5	-	116.1	2,521.7	- 551.9	1,969.8	-	116.1	2,085.9	824.4
2045	2,866.2	249.5	-	93.2	2,523.5	- 552.2	1,971.2	-	93.2	2,064.5	765.8
2046	2,693.3	249.5	-	75.0	2,368.9	- 518.3	1,850.5	-	75.0	1,925.5	714.8
2047	2,714.2	249.5	-	60.3	2,404.4	- 526.1	1,878.3	-	60.3	1,938.6	667.7
2048	2,639.3	249.5	-	48.6	2,341.2	- 512.2	1,829.0	-	48.6	1,877.6	625.7
2049	2,606.9	249.5	-	39.2	2,318.3	- 507.1	1,811.1	-	39.2	1,850.3	583.7
2050	2,590.3	249.5	-	31.6	2,309.2	- 505.1	1,804.1	-	31.6	1,835.7	546.2
2051	2,437.1	249.5	-	25.6	2,162.0	- 472.8	1,689.2	-	25.6	1,714.7	511.3
2052	3,073.1	249.5	-	20.7	2,802.8	- 613.7	2,189.1	1,760.0	20.7	449.8	112.1
2053	2,963.4	249.5	-	16.8	2,697.0	- 590.5	2,106.6	-	16.8	2,123.4	570.5
2054	2,932.3	249.5	-	13.7	2,669.1	- 584.3	2,084.8	-	13.7	2,098.5	534.9
2055	2,922.8	249.5	-	39.6	2,633.6	- 576.5	2,057.2	2,226.1	39.6	- 129.2	- 61.3

The low case hydrogen price is estimated not to be profitable, with a NPV of -4,276m NOK. On the other hand, base- and high- hydrogen price is yielding results with an NPV of respectively 3,138m, and 10,958m. The $\mathrm{IRR}_{\mathrm{Real}}$s are respectively 2.12%, 5.71%, and 8.74%, meaning a IRR of 4.85%, 8.44%, and 11.47%.

Figure 5.2: Sensitivity analysis Scenario 2



For sensitivity analysis we use the base price.

In the scenario we analyze two different breakeven points. The break-even price that results in a NPV of 0 is \$3.07/kg H2. The break-even price that results in a price equal to NPV generated in scenario 1 is \$3.56/kg H2.

The net present value varies from 5,161m to 1,098m with a change of 10% in the capital expenditures. Capital expenditures is a significant contributor to the total production cost. The breakeven threshold for capital expenditures is found to be a 15.4% increase. The breakeven discount rate is 8.44%, as indicated by the IRR presented above The revenue stream is as expected to be the most influential parameter for the NPV. The net present value varies from 1,851m to 7,036m with a change of 10% in the hydrogen price.

5.3 Scenario 3

In scenario three, we investigate the ability to produce both hydrogen and electricity with the option to switch production for revenue maximization.

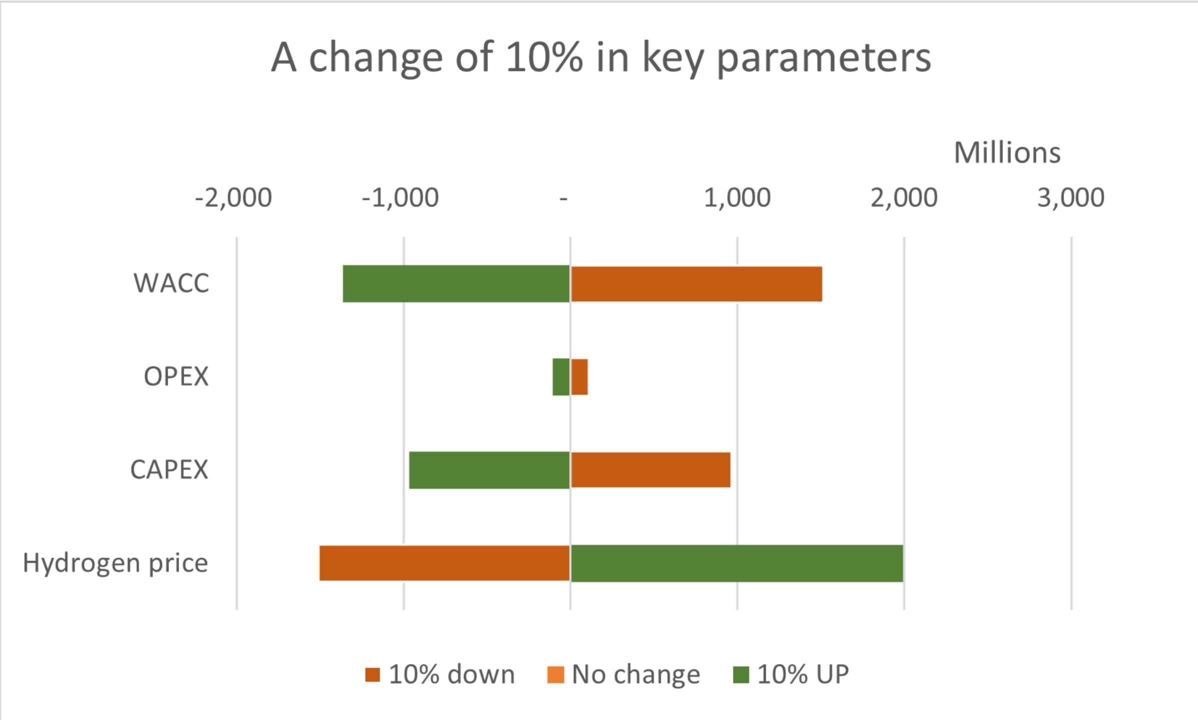
Table 5.3: Cashflows overview Scenario 3. Figure are displayed in million NOK.

Year	Revenue	OPEX	Planning/ Dev.	Depreciation	EBIT	Taxes	EAT	CAPEX	Depreciation	Free cash flow	Net present value
2022	-	-	- 478.0	-	- 478.0	- 478.0	- 956.0	-	-	- 956.0	- 478.0
2023	-	-	- 478.0	-	- 478.0	- 478.0	- 956.0	-	-	- 956.0	- 458.4
2024	-	-	- 478.0	-	- 478.0	- 478.0	- 956.0	-	-	- 956.0	- 439.5
2025	-	-	- 82.5	-	- 82.5	- 82.5	- 165.0	-	-	- 165.0	- 72.7
2026	-	-	- 82.5	-	- 82.5	- 82.5	- 165.0	-	-	- 165.0	- 69.7
2027	-	-	- 82.5	-	- 82.5	- 82.5	- 165.0	-	-	- 165.0	- 66.9
2028	-	-	- 69.7	2,360.5	- 2,430.2	- 2,430.2	- 4,860.4	12,701	2,360.5	- 15,201.5	- 9,229.1
2029	-	-	- 69.7	4,248.8	- 4,318.5	- 4,318.5	- 8,637.1	12,701	4,248.8	- 17,089.9	- 8,849.7
2030	2,933.8	360.8	-	3,399.1	- 826.1	- 826.1	- 1,652.1	-	3,399.1	1,746.9	1,839.1
2031	2,934.0	360.8	-	2,719.2	- 146.0	- 146.0	- 292.0	-	2,719.2	2,427.2	1,763.7
2032	2,941.0	360.8	-	2,175.4	404.9	404.9	809.7	-	2,175.4	2,985.1	1,695.8
2033	2,931.5	360.8	-	1,740.3	830.4	830.4	1,660.9	-	1,740.3	3,401.2	1,620.1
2034	2,931.9	360.8	-	1,392.3	1,178.9	1,178.9	2,357.8	-	1,392.3	3,750.1	1,553.8
2035	2,913.8	360.8	-	1,113.8	1,439.2	1,439.2	2,878.4	-	1,113.8	3,992.2	1,479.4
2036	2,911.3	360.8	-	891.0	1,659.5	1,659.5	3,319.1	-	891.0	4,210.1	1,417.3
2037	2,907.1	360.8	-	712.8	1,833.5	1,833.5	3,667.1	-	712.8	4,379.9	1,356.8
2038	2,906.9	360.8	-	570.3	1,975.8	1,975.8	3,951.6	-	570.3	4,521.9	1,300.9
2039	2,907.3	360.8	-	456.2	2,090.3	1,648.0	3,738.3	-	456.2	4,194.5	1,030.9
2040	2,919.0	360.8	-	365.0	2,193.3	1,710.8	3,904.0	-	365.0	4,269.0	975.1
2041	2,909.6	360.8	-	460.3	2,088.5	1,629.1	3,717.6	1,760.0	460.3	2,417.9	77.4
2042	2,909.6	360.8	-	179.6	2,369.2	1,848.0	4,217.2	-	179.6	4,396.8	899.2
2043	2,909.8	360.8	-	144.0	2,405.1	1,876.0	4,281.0	-	144.0	4,425.0	854.4
2044	2,921.4	360.8	-	115.5	2,445.2	1,907.2	4,352.4	-	115.5	4,467.9	816.9
2045	2,917.3	360.8	-	92.7	2,463.8	1,921.8	4,385.6	-	92.7	4,478.3	777.5
2046	2,917.7	360.8	-	74.4	2,482.5	1,936.3	4,418.8	-	74.4	4,493.2	742.1
2047	2,917.6	360.8	-	59.8	2,497.1	1,947.7	4,444.8	-	59.8	4,504.6	708.9
2048	2,922.3	360.8	-	48.1	2,513.5	1,960.5	4,474.0	-	48.1	4,522.0	678.9
2049	2,919.0	360.8	-	38.7	2,519.6	1,965.3	4,484.9	-	38.7	4,523.6	648.6
2050	2,919.3	360.8	-	31.2	2,527.3	1,971.3	4,498.7	-	31.2	4,529.8	620.8
2051	2,919.1	360.8	-	25.1	2,533.2	1,975.9	4,509.1	-	25.1	4,534.2	594.3
2052	2,922.1	360.8	-	20.3	2,541.0	1,982.0	4,523.0	1,760.0	20.3	2,783.3	569.8
2053	2,917.2	360.8	-	16.4	2,540.0	1,981.2	4,521.2	-	16.4	4,537.7	544.8
2054	2,917.5	360.8	-	13.3	2,543.4	1,983.8	4,527.2	-	13.3	4,540.6	522.1
2055	2,904.4	360.8	-	32.4	2,511.2	1,958.7	4,469.9	2,226.1	32.4	2,276.3	- 63.7

The price scenario is base case hydrogen price.

One of the most interesting parameters to investigate in the switching scenario, is the amount of hydrogen sold. In the low case, 60.3% of total electricity is used for hydrogen production. In the base- and high case the average for all price scenarios is respectively 86.8% and 94.5%. IRR_{Real} is respectively, 5.21%, 7.58% and 11.03% in the three different price levels, all three above the cost of capital calculated previously. For a comparison to other investments, the nominal internal rate of return is 7.94%, 10.31%, and 13.76%. This leads to positive NPV for the three different hydrogen prices. In the low case, the NPV is calculated to be 269m. For respectively the base- and high price, the NPV is 5,360m and 13,895m. Both exceeding the NPV of a stand-alone offshore wind farm.

Figure 5.3: Sensitivity analysis Scenario 3



The most influential parameter to change is the price of hydrogen as observed in the figure 5.3. The change in NPV with a change of 10% for both hydrogen price, and cost of capital is exceeds 1 billion. A change in Capex of 10% is slightly below 1 billion. While the operational expenses have a minor effect the result.

5.4 Scenario 4

To calculate the impact of energy storage through BESS or pumped hydro reservoir storage, we calculate the incremental revenue accumulated from storing energy during off-peak hours and reselling it in peak hours. In table 5.4 cash flows of a 100MW lithium-ion battery is presented.

Table 5.4: Cashflows overview Scenario 4. Figure are displayed in million NOK.

Year	Revenue	OPEX	Depreciation	EBIT	Taxes	EAT	CAPEX	Depreciation	Free cash flow	Net present value
2022	-	-	-	-	-	-	-	-	-	-
2023	-	-	-	-	-	-	-	-	-	-
2024	-	-	-	-	-	-	-	-	-	-
2025	-	-	-	-	-	-	-	-	-	-
2026	-	-	-	-	-	-	-	-	-	-
2027	-	-	-	-	-	-	-	-	-	-
2028	-	-	-	-	-	-	-	-	-	- 272.0
2029	-	-	68.0	- 68.0	-	- 68.0	340.0	68.0	- 340.0	- 285.6
2030	46.9	17.0	122.4	- 92.5	-	- 92.5	340.0	122.4	- 310.1	- 334.6
2031	46.9	17.0	97.9	- 68.1	-	- 68.1	-	97.9	29.9	29.9
2032	47.1	17.0	78.3	- 48.3	-	- 48.3	-	78.3	30.1	30.1
2033	46.9	17.0	62.7	- 32.8	-	- 32.8	-	62.7	29.9	29.9
2034	46.9	17.0	50.1	- 20.2	-	- 20.2	-	50.1	29.9	29.9
2035	43.9	17.0	40.1	- 13.2	-	- 13.2	-	40.1	26.9	26.9
2036	44.1	17.0	32.1	- 5.0	-	- 5.0	-	32.1	27.1	27.1
2037	43.9	17.0	25.7	1.3	-	1.3	-	25.7	26.9	26.9
2038	43.9	17.0	20.5	6.4	-	6.4	-	20.5	26.9	26.9
2039	43.9	17.0	16.4	10.5	-	10.5	-	16.4	26.9	26.9
2040	44.1	17.0	13.1	13.9	-	13.9	-	13.1	27.1	27.1
2041	44.0	17.0	10.5	16.4	-	16.4	-	10.5	27.0	27.0
2042	44.0	17.0	8.4	18.5	-	18.5	-	8.4	27.0	27.0
2043	44.0	17.0	6.7	20.2	-	20.2	-	6.7	27.0	27.0
2044	44.1	17.0	5.4	21.7	-	21.7	-	5.4	27.1	27.1
2045	43.9	17.0	4.3	22.6	-	22.6	-	4.3	26.9	26.9
2046	43.9	17.0	3.4	23.5	-	23.5	-	3.4	26.9	26.9
2047	43.9	17.0	2.8	24.2	-	24.2	-	2.8	26.9	26.9
2048	44.0	17.0	2.2	24.8	-	24.8	-	2.2	27.0	27.0
2049	44.0	17.0	1.8	25.2	-	25.2	-	1.8	27.0	27.0
2050	44.0	17.0	1.4	25.6	-	25.6	-	1.4	27.0	27.0
2051	44.0	17.0	1.1	25.9	-	25.9	-	1.1	27.0	27.0
2052	44.2	17.0	0.9	26.3	-	26.3	-	0.9	27.2	27.2
2053	44.1	17.0	0.7	26.3	-	26.3	-	0.7	27.1	27.1
2054	44.1	17.0	0.6	26.5	- 2.6	23.9	-	0.6	24.5	24.5
2055	44.1	17.0	0.5	26.6	- 5.9	20.8	-	0.5	21.2	21.2

The NPV of implementing a BESS storage with lithium-ion batteries is -213m. The IRR_{Real} is -1.92%, and the IRR is 0.81%.

The cashflow associated with PHS is also negative. Compared to BESS, the cost of installed capacity, the degradation p.a, and the round-trip efficient is unfavorable. The main advantage of PHS is the long expected lifetime. However, as the wind farm is assumed to exist for 25 years, the full lifetime is not realized. The remaining years of the lifetime would be discounted with a high accumulated rate, meaning the effect on the net present value is mitigated. To fully examine the lifetime, we would need to calculate the cost of using the grid network as a substitute for the electricity generated at the wind farm. This includes grid fees, and would further decrease the profitability.

5.5 Combined

Table 5.5 contains all NPVs, IRR_{Real}, and IRRs for all scenarios

Table 5.5: Overview of results presented

Metric	Scenario 1	Scenario 2			Scenario 3			Scenario 4
		Low	Base	High	Low	Base	High	BESS
NPV	3,569	- 4,276	3,138	10,958	269	5,369	13,895	- 213
IRR_{Real}	6.48 %	2.12 %	5.71 %	8.74 %	5.21 %	7.58 %	11.03 %	-1.92 %
IRR	9.21 %	4.85 %	8.44 %	11.47 %	7.94 %	10.31 %	13.76 %	0.81 %

6 Discussion

6.1 Discussion

The objective of the thesis is to understand the economic viability and variables affecting the feasibility of investing in an offshore wind farm, and hydrogen production. The data provide evidence of the wind farm being a positive NPV investment, with an real internal rate of return of 6.48% and a nominal rate of return of 9.21%. In addition, we found a positive effect of the option to produce only hydrogen when the price exceeds $3.56/kg. We observe that coupling an offshore wind farm produces the highest IRR and NPV. Further in the chapter, we will discuss the implication of the results, limitations of data and methodology used, and suggest topics and interpretation of future work within the field.

6.1.1 Interpretation

The analysis presented results in line with the expectations of a positive net present value for an offshore wind farm. The results are following the development in ongoing auctions of constructing wind farms. RWE recently won a tender agreeing to pay DKK2.8Bn for the right to build a 1GW wind farm in Denmark (Danish Energy Agency, 2021). In contrast, a recent study found the Dogger-bank wind farm only to be profitable at a discount rate of 5.6% (Osmundsen, 2021). However, our analysis's internal rate of return was slightly higher than expected. In addition, to be economically profitable, the externalities created through the environmental dimension make it an exceptional investment.

In combination with the standalone offshore wind farm, the results of exclusively producing hydrogen, and as a part of a switching option, were unexpectedly good. With a break-even at a hydrogen price of $3.56/kg, the results suggest hydrogen as a solution of substituting polluting fuel in the long-haul transport sector and decarbonizing the industry, to be realistic in the following years. Nonetheless, the results from scenario four lack evidence of PHS or BESS to be the universal solution to the storage puzzle. However, PHS using existing reservoirs may yield other results.

6.1.2 Limitations

6.1.2.1 Implications of capital expenditures estimation

Because capital expenditures are a crucial part of the valuation, it is essential to note the uncertainties in the estimation. The cost estimates are extracted from a review of a broad spectrum of literature. Thus, we intend to attach a nuanced picture of the development and construction cost of inputs related to the four scenarios. However, the lack of transparency of actual costs in large undertaken wind farm projects using turbines with high rated power may inaccurately calculate the effect of economies of scale. In the analysis, we use a prototype 15MW turbine to capture the potential cost-benefit of future technological development. While providing exciting views on future profitability, it creates more uncertainties in cost estimation. Through the analysis, we have reached out to Vestas and Siemens to examine firsthand cost estimation. Unfortunately, due to "confidential reasons" information could not be shared. Another point worth mentioning is the tendency for costs to overrun. Overruns in actual cost compared to estimated cost is argued by Sovacool et al., (2016) to be 9.6% on average. Hydrogen capital expenditures also include uncertainties. The technology is in the development phase and scale of 100+MW elctrolyzers have yet to be achieved.

6.1.2.2 Implication of electricity price forecast

As electricity price forecasts are based on long-term projections, uncertainty is expected. At the time of writing this thesis, Norwegian electricity prices are nearing all-time highs, and recency bias must be avoided. The long-term forecasts used in this analysis are published in 2020, mitigating this. There are uncertainties on the long-term consequences of a higher degree of Norwegian power market integration with the rest of Europe and an increasing share of energy coming from renewable sources.

6.1.2.3 Implication of wind data

For estimation of wind speed, we use data from Ekofisk. The data is important for the amount of generated wind, and a decline in wind speed would significantly reduce economic profitability. The location of Ekofisk is further from shore than the hypothetical wind farm. Thus, the amount of wind could give a positive bias from more stable wind.

We did not adjust the wind speed for any developments in the future, in accordance with the literature in the field (Pryor and Barthelmie, 2010). However, significant climate change may lead to more extreme weather conditions decreasing or increasing the time rated power is reached. Lastly, the effect of adjusting wind speeds to the turbine hub height of 261m compared to the 69m where the wind data is sampled is uncertain.

6.1.2.4 Implications of a flat hydrogen price

As presented in the sensitivity analysis on scenarios 2 and 3, the most influential variable on the profitability from hydrogen production is the price. In the thesis, we assume a flat price during the period, without correlation with the electricity price. This assumption simplifies the analysis; however, it is reasonable to expect it to be unrealistic. Depending on the application of hydrogen as an energy carrier, it is plausible for the price to follow the historical development of substituting energy sources. In contrast to a scenario where hydrogen is used as a storage option for electricity redistribution into the electricity network, where the correlation between hydrogen and electricity prices would be significant. The importance of determining a realistic hydrogen price is as presented in section 5.3 and 5.4 of great importance. In addition, a high positive correlation between hydrogen- and electricity prices would decrease the net present value of scenario 3, due to reduced spread between hydrogen and electricity prices.

6.1.2.5 Implication of discount rate estimates

The cost of capital used through all four scenarios is, as mentioned, calculated slightly above the average industry cost of equity of 5.93% (Damodaran, 2021). Using a lower cost of capital would increase the valuation. We assumed the capital cost to be equal across the scenarios for simplifying reasons. It may be inaccurate, with scenario two to have increased risk due to the valuation's dependency of the immature hydrogen market. For scenario three, the discount rate could arguably be too high based on the option to switch between the two products, as this provides a diversification effect. With a non-perfect correlation between the price of electricity and hydrogen, the risk decreases. However, as argued in section 3.1.3, the correlation depends on the application of hydrogen as an energy carrier. With a correlation less than 1, the risk, and therefore the cost of capital decreases.

6.1.2.6 Implications of lifetime estimation

The turbines in the wind farm is assumed to not require any major maintenance or repowering operation through the 25 years. Despite some literature expecting a change of turbine blades after 15 years. However, there is no universal agreement of this to be required. At the end of the operating lifetime, we assume a decommission of the wind farm. In the literature, it is common to assume the income from waste management to be equal to the decommissioning cost. Nonetheless, as presented in chapter 3.2.2.4, we include total decommissioning costs. On the other hand, it is realistic to believe a more beneficial technology or restructuring path for wind farms to exist in 2055, which increases the value.

6.1.2.7 Implication of price taker assumption

Throughout the thesis, we assume the project to be price-taking. It means that the price would not change independent of the volume supplied. The estimated electricity is on average 72.27 TWh per year, which is 0.21% of the total volume offered to buy in the NO2 area in 2019 (NordPool, 2021c). To calculate the elasticity in the price is a complex process, with daily changes. However, the amount of electricity supplied is possible to have a price moving effect, reducing the wind farm's profitability. In the case of hydrogen production, it will again depend on the area of application, where the market for natural gas and oil is significantly larger than electricity in the NO2 area. Therefore, if hydrogen develops to be a substitute for natural gas or oil, the price-taking assumption is reasonable.

6.1.3 External validity

We have developed a framework for evaluating an offshore wind farm located in the North Sea, connected to the NO2 Norwegian electrical grid network. Thus, there are some aspects related to external validity to be considered. Foremost, the wind data is sampled from a unique placement. The stability and wind speed variation across locations is vast, and investment in different areas would require research of the wind characteristics in the unique location. Furthermore, the electricity prices vary between regions within Norway, and even more across countries. This valuation is based on the daily, weekly, seasonal, and yearly fluctuations in the NO2 region and is not directly transferable to other markets.

Also, other characteristics such as curtailments and grid connection fees can be different for other markets. Lastly, the accounting rules for tax calculations based on deferred tax benefits are built on specific Norwegian rules and may differ from other countries' tax laws.

6.1.4 Further work

We will propose a exciting topic to examine for further work within the field of renewable energy and storage, which we could not include.

We found the option of hydrogen as a substitute for fuel and industry energy requirements to be compelling and feel the decarbonization of these sectors to have the most potential. Therefore, a tempting suggestion is to examine the scenario three option in combination with a volatile hydrogen price, with a base in the volatility of natural gas and crude oil adjusted for MMBtu. It could also be interesting to see the correlation towards the electricity price, which could make the switching option more or less profitable.

7 Conclusion

Throughout the thesis, we have presented the steps in developing a valuation framework of four unique scenarios for the use of electricity generated at an offshore wind farm. The objectives were to examine the economic profitability to establish evidence of investments in offshore wind as a reasonable solution in the ongoing transition to green energy creation. Based on the discounted cash flow analysis, we presented evidence of the wind farm to be profitable without subsidies. The results indicate even stronger profitability when including hydrogen production as a part of a switching option. However, the analysis suggests the two storing options in scenario 4 to be too costly.

By analyzing changes in important parameters, we provide an overview of the possible impact for the results. The most critical parameter for all scenarios are the hydrogen or electricity prices, where small deviations significantly impact the net present value.

Based on our results, the optimal approach for maximizing net present value when installing a offshore wind farm is scenario 3, where the offshore windfarm is coupled with an onshore hydrogen production facility. For scenario 2, where the windfarm is coupled with an offshore electrolyzer and only hydrogen is produced, we have a break-even hydrogen price of \$3.07/kg and the price needed for the NPV to exceed scenario 1 is \$3.56/kg.

Through the bottom-up valuation approach, we provided evidence of the economic viability of an offshore wind farm off the western coast of Norway. Through both direct sale of electricity, but preferably in combination with hydrogen, the risk-adjusted return indicates it's time for significant investments.

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Appendix

Appendix A: Wind profile power law

To calculate the available electricity generated, we use available data from hourly air flows at the Norwegian offshore petroleum platform Ekofisk. The platform is located southwest in the North-sea and provides information about the wind speed 69m above sea level. Thus, the nacelle height is located 261m above sea-level. To calculate the wind speed 261m above sea level, we could apply the power law presented in eq. below

$$V_2 = \quad V_1 * (\frac{Z_1}{Z_2})^{\alpha} \tag{.1}$$

V_1: Velocity at Z_1

V_2: Velocity at Z_2

Z_1: Lower height

Z_2: Upper height

α: Wind shear exponent

According to Werapun (2017), the usual wind shear component for analysis is 0.143. As Ekofisk is located 69m above sea level, and the wind turbine is 261m above sea level giving us respectively Z_1 and Z_2. V1 is the mean wind speed observed at Ekofisk.

Appendix B: Energy output

The wind speeds calculated above are calculated into energy output by the relationships below

$$E_t^{Wind} = \varrho * A * \ V_2^3 * 0.5 \tag{.2}$$

ρ: Air density

A: Swept diameter

V: Velocity (m/s)

The air density is set to a value of 1.25 (Ulazia et al., 2019). Although the density fluctuates across the year, the ability to include the appropriate density factor through the year is close to impossible, due to a complex determination. The air density is set by a non-linear relationship by factors including atmospheric pressure, wind speed, humidity, height above sea level, and latitude (Kaczor, 2018).

From the wind energy calculation, we can estimate the true energy output by adjusting for the efficiency of the generator. The theoretical efficiency maximum is 59%, known as the Betz limit. The average generator efficiency in the US is 35% (Berkley lab et al., 2021). According to the University of Michigan, the efficiency is expected to increase to 51% for projects undertaken from 2022 (University of Michigan, 2021)

Furthermore, the wind energy output is calculated using equation 4.1

$$E_t^{Output} = E_t^{Wind} * Generator\ efficiency \tag{.3}$$

Appendix C: Summary statistics for deterministic model for future prices

Table A0.1: Summary statistics for deterministic model for future prices

	Dependent variable:
	KRS
Hours01	-2.054
	(2.333)
Hours02	-11.110***
	(2.335)
Hours03	-17.360***
	(2.333)
Hours04	-20.430***
	(2.333)
Hours05	-18.010***
	(2.333)
Hours06	-6.604***
	(2.333)
Hours07	9.841***
	(2.333)
Hours08	31.730***
	(2.333)
Hours09	48.020***
	(2.333)
Hours10	45.070***
	(2.333)
Hours11	38.320***
	(2.333)
Hours12	32.470***
	(2.333)
Hours13	26.620***
	(2.333)
Hours14	21.690***
	(2.333)
Hours15	18.870***
	(2.333)
Hours16	20.900***
	(2.333)
Hours17	29.140***
	(2.333)
Hours18	40.550***
	(2.333)
Hours19	42.670***
	(2.333)
Hours20	35.350***
	(2.333)
Hours21	26.180***
	(2.333)
Hours22	20.150***
	(2.333)
Hours23	12.650***
	(2.333)
seasonSpring	-3.623***
	(0.961)
seasonSummer	-4.661***
	(0.960)
seasonWinter	-0.610
	(0.961)
AvgLast	0.958***
	(0.002)
Constant	-1.570
	(1.850)
Observations	60,953
R^2	0.875
Adjusted R^2	0.875
Note:	*p<0.1; **p<0.05; ***p<0.01