Master's thesis

NTNU
Norwegian University of Science and Technology

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A feasibility study of wind powered hydrogen production at Fosen

A win-wind situation

Master's thesis in Energy and Environment
Supervisor: Bruno G. Pollet
June 2019

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Problem description

This thesis examines the potential for producing hydrogen via wind-powered electrolysis at the new wind farm Fosen Vind in Trøndelag. It is a collaboration with TrønderEnergi AS to calculate the cost of such a production facility.

The thesis agreement contained the following tasks:

- Gather information about the wind park project
- Look at the minimum and maximum energy production per year for each of the six wind farms
- Compare alkaline and PEM electrolysers
- Assume cost associated with producing power from wind farms: how much would it cost to produce electricity.
- Estimate how much one wind farm would sell its energy for
- Compare production of hydrogen by Norwegian wind power with the electricity mix of another European country.
- Estimate the cost per kg hydrogen

Preface

This thesis is the conclusion of a Master of Science at the Norwegian University of Science and Technology (NTNU) in Energy and Environment. My degree specialization is Energy planning and environmental analysis.

The writing of this thesis required a large research effort in new areas of expertise, which was a challenging and rewarding learning experience.

I would like to thank my supervisor, Bruno G. Pollet, for valuable counsel and insightful feedback, and for motivation throughout the process. I would also like to thank the Head of Development at TrønderEnergi, Bernhard Kvaal, for establishing this collaboration with TrønderEnergi and for providing relevant data, insight and considerations. Lastly, I would like to thank my parents. Without their support and motivational words this thesis would not be possible.

Trondheim, June 10th, 2019

Magnus Fure Runnerstrøm

Magnus Fure Runnerstrøm

Sammendrag

Hydrogen (di-hydrogen, H2) er et ettertraktet drivstoff fordi det er det vanligste og letteste stoffet i universet, med to til tre ganger høyere energitetthet enn tradisjonelle drivstoff. Hydrogen kan produsere energi og vann via brenselsceller uten karbonutslipp. De vanligste industrielle produksjonsmetodene er dampmetanreformering og vannelektrolyse. Hydrogen produsert via elektrolyse er en attraktiv metode så lenge elektrolysen er drevet av fornybar energi.

Denne oppgaven undersøker muligheten for å produsere «grønt hydrogen» til en konkurransedyktig pris via vindkraft på Fosen i Trøndelag. Fosen Vind bygger for øyeblikket Europas største onshore vindkraftanlegg, med seks (6) vindparker på totalt 1 GW (3,6 TWh). Det tekniske aspektet ved hydrogenproduksjon via vindkraft er bevist mulig, men de økonomiske betingelsene er ikke ideelle. Vindkraftens varierende energiproduksjon utgjør en utfordring for å sikre tilstrekkelig driftstid. I tillegg er det vanskelig å utkonkurrere tradisjonelle drivstoff så lenge hydrogen forblir en liten industri. Ved å se på kapital- og driftsutgifter (CAPEX og OPEX) for forskjellige elektrolyseteknologier, lagringsteknologi og transport, kan kostnaden per kg for hydrogen bli beregnet. Disse utgiftene ble beregnet over en femtenårsperiode (basert på forventet levetid for elektrolyseutstyr) med en diskonteringsrente på 8%. Ettersom kostnaden ved elektrolyse hovedsakelig bestemmes av strømprisen ble kostnadene beregnet for et stort spenn av strømpriser basert på forventede strømpriser det kommende tiåret. Deretter ble disse kostnadene sammenliknet med nasjonale og internasjonale opplysninger for å anslå konkurransedyktigheten og sette kostnadene i perspektiv. Når den nødvendige informasjonen var tilgjengelig ble ulike deler av beregningene også sammenliknet med offentlig tilgjengelig kostnadsinformasjon for å vurdere reliabiliteten til beregningene (beregningene krevde antagelser som stammet fra tilsendte opplysninger). Disse sammenlikningene viste at sluttresultatene var i korrekt størrelsesorden, hvilket styrket reliabiliteten til beregningene. Kildene til CAPEX og OPEX for elektrolysørene stammet fra markedsaktører og publiserte vitenskapsartikler. Dette ga tilgang på mer nøyaktig data, men ettersom markedsaktørene krevde anonymisering kan ikke deres data bli verifisert av andre.

Gjennom denne undersøkelsen ble det funnet at mulig kostnadsspenn for hydrogenproduksjon via vindkraft på Fosen er 25,77-31,51 NOK/kg. Disse kostnadene er basert på forventet gjennomsnittlig strømpris det kommende tiåret på 32 øre/kWh (for øyeblikket er strømprisen på 55 øre/kWh før skatt). Disse beregningene er veiledende tall som blant annet påvirkes av valg av elektrolyseteknologi. De totale kostnadene inkludert lagring og transport ble beregnet til å være 46,78-53,13 NOK/kg for komprimert hydrogen, og 51,26-63,00 NOK/kg for flytendegjort hydrogen (LH2). Ettersom foreløpige hydrogenpris er 90 NOK/kg indikerer de beregnede kostnadene for Fosen Vind at de er kapable til å produsere hydrogen til en konkurransedyktig pris. Med andre ord, resultatene tilsier at kostnaden er tilstrekkelig under nåværende markedspris til at en hydrogenproduksjonsenhet på Fosen kan være lønnsom. Resultatene indikerer også at en hydrogenproduksjon basert på overskuddsstrøm (peak-shaving) ikke er lønnsomt, da en slik investering krever langt flere driftstimer enn det overskuddsstrømmen kan levere.

Det ble beregnet at Fosen potensielt kan produsere 10 000 tonn grønt hydrogen per år, nok til å drive 80 000 biler.

Abstract

Hydrogen (di-hydrogen, H_2) is a coveted fuel due to it being the most common and lightest substance in the universe, with two to three times higher energy density than traditional fuels. Hydrogen can produce energy and water when used in a fuel cell with zero carbon emissions. The most common industrial methods for producing Hydrogen are by steam methane reforming (SMR) and water electrolysis. Renewable hydrogen is an attractive method as long as water electrolysers can be powered by renewable energy technologies.

This study investigates the feasibility of producing "green hydrogen" at a competitive price via wind power at the Fosen site, in Trøndelag county, Norway. Fosen Wind is currently building Europe's largest onshore wind power plant, with six (6) wind farms totaling 1 GW (3.6 TWh). The technical aspect of hydrogen production via wind power is shown to be possible, but the economic framework conditions are not ideal. The fluctuating nature of wind represent a challenge to ensuring sufficient operation time. Furthermore, outcompeting established traditional fuels is difficult as long as hydrogen remain a small industry. By looking at Capital Expenditure and Operating Expenses (CAPEX and OPEX) of different electrolyser technologies, storage technology and transport, costs per kg of hydrogen were calculated. They were generated over a 15-year period (based upon the expected lifetime of the electrolysers) at a discount rate of 8%. Since the cost of electrolysis is mostly determined by the electricity price, costs were calculated for a large span of electricity prices based upon expected electricity prices in the coming decade. Furthermore, these costs were compared with national and international data to assess competitiveness and put the costs into perspective. When the required data were available, various parts of the calculations were also evaluated against public cost information to assess the reliability of the calculations (the calculations required assumptions which were based upon supplied information). These comparisons showed that the end-results were in the correct order of magnitude, which strengthened the reliability of the generated data. The sources of CAPEX and OPEX for electrolysers originated from main market actors and published peer-reviewed technical articles. This gave access to more accurate data, although the main market actors requested confidentiality, thus the data cannot be verified by others.

Through this investigation, it was found that the costs of producing hydrogen via wind-powered electrolysis at Fosen could be in the range of around 25.77-31.51 NOK/kg. These costs are based upon a projected average electricity price for the next decade of 0.32 NOK/kWh (the current electricity price in Norway is 0.55 NOK/kWh exc. tax). These figures are indicative numbers which are affected by the choice of electrolyser technologies. Furthermore, the total costs including storage and transport were found to be 46.78-53.13 NOK/Kg for compressed hydrogen (CH2) and 51.26-63.00 NOK/kg for liquefied hydrogen (LH2). As the current retail price of hydrogen in Norway is around 90 NOK/kg (inc. tax), the calculated cost indicates that Fosen Wind is capable of producing hydrogen at a market competitive cost. In other words, it was found that the cost is sufficiently below the current market price and it is possible that a hydrogen production facility at Fosen could be profitable. The results also indicated that hydrogen production based upon surplus power (peak-shaving) does not pay off, as investment costs require an operation time significantly larger than what surplus power can supply.

It was calculated that the Fosen site could potentially produce around 10,000 tons of green hydrogen per annum, enabling to fuel 80,000 cars.

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Nomenclature

- CAPEX – Capital Expenditure

- OPEX – Operating expenses
- PEM – Polymer Electrolyte Membrane
- Tpd – tons per day
- wt% - weight percentage
- v% - volume percentage

Chapter 1 Introduction

1.1 Introduction

The world is not facing a question of what to do - eliminate fossil fuels by 2050 – but how to do it [1]. Mitigating climate change is a global challenge which requires global participation, restructuring our society, and continued development of renewable energy. Through the Paris Agreement Norway has committed to reducing carbon emissions by 40 percent by 2030. After half a century as an oil enhanced economy Norway possesses the economic power, and has the responsibility, to restructure and commit to renewable forms of energy [2]. Drastic measures need to be taken, as Norwegian carbon emissions actually increased during 2018 [3] [4]. However, since carbon-low hydro power dominates Norwegian power production, mitigation action must unlike in most other countries be taken outside the energy sector. Norway is blessed with renewable energy sources such as wind and hydro power that needs to be deployed within the transport sector (representing 30% of Norway's emissions) to reach the mitigation targets [5].

The preferred renewable energy carrier has been electricity charged batteries. However, batteries face several challenges; lack of range, high cost and lack of recharge infrastructure [6]. An energy intensive energy carrier like hydrogen (di-hydrogen, H_2) is a potentially carbon-free solution to these challenges. Carbon-free hydrogen can be produced by renewable electricity through electrolysis and function as a clean and energy-intensive energy carrier in transport, and as a feedstock in industry. Hydrogen is a part of the new energy solution which will help reach Norway's mitigation targets.

Hydrogen produced by renewable power sources is already cost competitive with fossil fuels in some cases [7] [8]. As the hydrogen industry and technology is developing fast in a complex system of infrastructure, mitigation policy and energy demand, detailed case studies are necessary in order to assess the feasibility of hydrogen production. This thesis is a case-study investigating the potential for producing hydrogen in connection to the Fosen Wind project. In Trøndelag county, Fosen Wind is constructing the largest onshore wind park in Europe. The 1 GW facility will produce 3.6 TWh[1] annually and combined with its central location in Norway it possesses the potential to be a hydrogen hub for Norwegian marine and land activity. These considerations result in the research question for this thesis being

Can Fosen Wind produce hydrogen at a market competitive cost?

The ability to produce hydrogen at Fosen is determined by financial constraints, hence this thesis will conduct a literature research and contact market actors to calculate Capital Expenditure and Operating Expenses (CAPEX and OPEX) for production, storage and transport, and investigate the total production capacity. The final cost is set into a national and international context in order to put costs at Fosen Wind into perspective. The objective is to offer an evaluation of Fosen Wind's hydrogen production potential to part-owner TrønderEnergi AS and their partners. TrønderEnergi have supplied council and data from other projects to facilitate this thesis.

The remaining of chapter 1 will present the problem description, then introduce the subject of hydrogen, its production, storage and transport, and then wind power and Fosen Wind. Chapter 2 is the methodology chapter which presents the main assumptions and procedures for calculating cost related to hydrogen production, storage and transport.

[1] Enough to power 225,000 average Norwegian households [185]

These costs are then presented and discussed in chapter 3 – Results and discussion. Then, in chapter 4 – Further comments – other important aspects besides pure economic ones are presented. These inform any judgement making, provides context to the results and ensures that the calculated results are in the right order of magnitude and thereby increases the reliability of the assumptions used. Chapter 5 sums up the information conveyed in this thesis and presents conclusions to the research question and main questions regarding a hydrogen production facility at Fosen. Lastly, chapter 6 presents and discusses recommendations and ideas for further work is presented and discussed.

1.1.1 Problem description

The research question originates from a thesis agreement which contained the following tasks:

- Gather information about the wind park project
- Look at the minimum and maximum energy production per year for each of the six wind farms
- Compare alkaline and PEM electrolysers
- Assume cost associated with producing power from wind farms: how much would it cost to produce electricity.
- Estimate how much one wind farm would sell its energy for
- Compare production of hydrogen by Norwegian wind power with the electricity mix of another European country.
- Estimate the cost per kg hydrogen

These tasks sum up a goal of describing the potential for producing hydrogen at Fosen, and this goal is attempted encapsulated in the research question in order to provide a guiding line for the thesis as a whole.

1.2 Hydrogen energy

Hydrogen is a coveted fuel because it possesses several very advantageous characteristics. As the most common, simplest and lightest element in the universe, hydrogen provides 2-3 times more energy than traditional fuels and only need oxygen to produce energy without carbon emissions [9]

$$2H_2(g) + O_2\,(g) \rightarrow 2H_2O\,(g) + \boldsymbol{energy} \qquad (1)$$

However, hydrogen is very rarely found in its molecular form. Hence, it needs to be extracted from larger molecules like water (H_2O) and methane (CH_4). Hydrogen is an energy carrier, not a source. This means that the choice of hydrogen production method is crucial in determining how environmentally friendly the hydrogen will be, and there are a lot of different well-matured production technologies (see Figure 1).

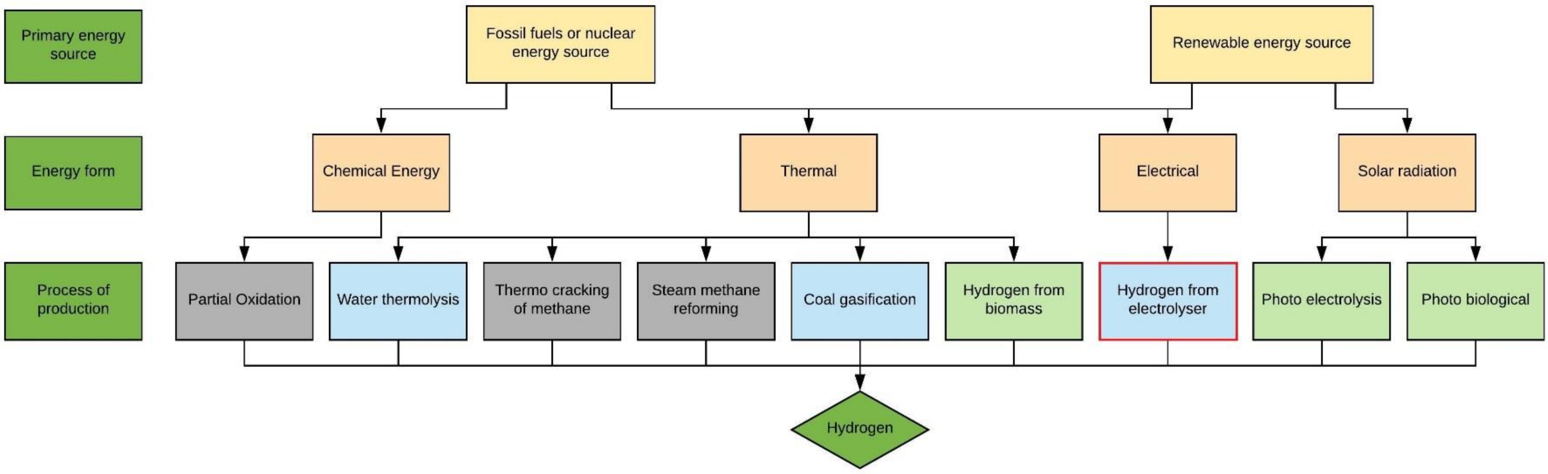

Figure 1 Classification of hydrogen production methods, adapted from *[151]*

Today around 96 percent of the global hydrogen production is based on primary fuels and the resulting hydrogen is therefore not carbon-free [10]. However, the motivation for producing hydrogen at Fosen is mostly due to the goal of carbon emission mitigation. Hence only carbon-free or carbon-low hydrogen is of interest. This gives rise to two relevant categories of hydrogen which is called *green hydrogen* and *blue hydrogen*. Green hydrogen is hydrogen production powered by renewable energy sources, with minimal carbon emissions[2]. Blue hydrogen is produced by conventional energy sources (from primary fuels) but includes Carbon Capture and Storage (CCS) to remove carbon emissions in the production stage. The hydrogen produced at Fosen will therefore be green hydrogen, hydrogen produced by renewable energy sources. More precisely, this project will result in green hydrogen produced through *electrolysis* powered by wind power.

Electrolysis is the process by which an electric current is passed through a substance to power a chemical reaction which produces hydrogen. An electrolyser consists of a DC source (wind turbine), two electrodes and an electrolyte (an ionic conductor). This allows for hydrogen to be produced by splitting water (H_2O) into hydrogen and oxygen by passing a direct current through the water. There are four electrolysis methods; Alkaline water electrolysis, solid oxide electrolysis, microbial electrolysis and Proton Exchange Membrane water electrolysis (PEM).

Out of these four there are two leading, matured technologies, PEM and Alkaline. Both technologies are classified as low temperature electrolysis as the maximum temperature typically is below 100°C [11]. Solid oxide electrolysis is a high temperature technology still in the R&D phase with considerable developments needed, and microbial electrolysis is not sufficiently matured. Therefore, only alkaline and PEM electrolysis technology will be investigated in this thesis as these are the only viable options. In the following section alkaline and PEM electrolysis will be presented.

[2] There are no carbon emissions from the mentioned process itself. However, in a lifecycle perspective the production and disposal stage will produce greenhouse gases. The emissions remain very low but cannot be said to be carbon-free.

1.2.1 Electrolyser technologies

1.2.1.1 Alkaline Water Electrolysis

Alkaline electrolysis has been the standard production technology of hydrogen for many decades, and an important part of Norwegian industry since the late 1920s [12] [13]. Of the production alternatives it is the most matured technology.

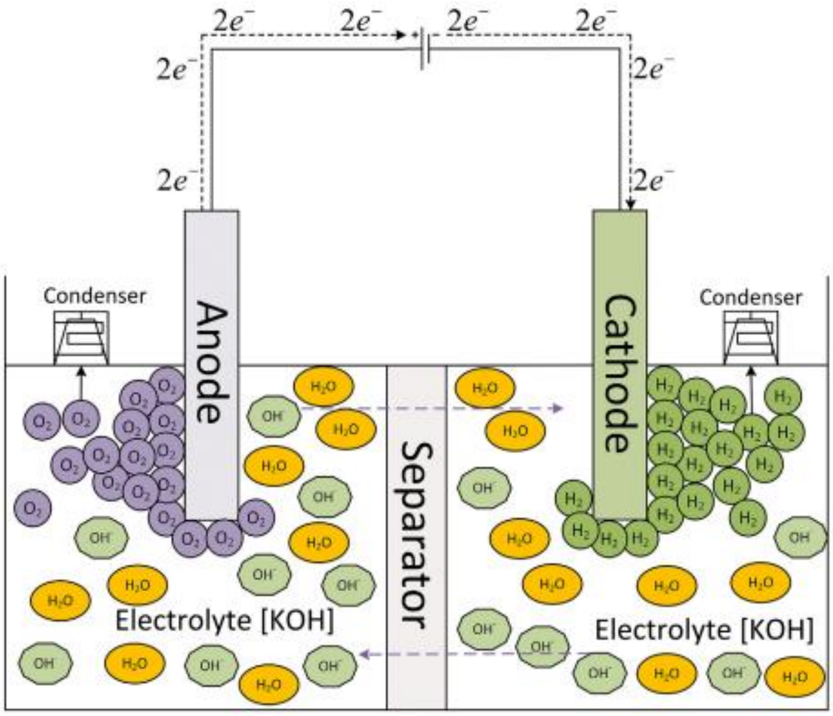

Figure 2 Schematic of an alkaline electrolyser cell [26]

The cathode releases electrons into the electrolyte (see Figure 2). This dissociates water, which produces hydrogen (H_2) and hydroxide ions (OH-). The charge carriers (hydroxide ions) then move through the membrane toward the anode (the positive pole). Here the electrons are absorbed by the negative OH^--anions. This oxidizes the OH^--anions which forms water and oxygen, and oxygen rises at the anode. The separator prevents the product gases from mixing but allows for the passage of OH^- ions. This process is chemically expressed as such:

$$2H_2O + 2e^- \rightarrow H_2 + 2OH^-$$

$$2OH^- \rightarrow H_2O + \frac{1}{2}O_2 + 2e^-$$

However, alkaline electrolysers may produce impure H_2 if in intermittent operation, and quick power fluctuations may lead to incomplete separation of H_2 and O_2. Another issue is operational challenges caused by periods of low energy input. Since the alkaline electrolyte is very corrosive [14] (The A-series of NEL Hydrogen require a 25% KOH aqueous solution which is a strong base [15]), the electrode will corrode in times of ceased production. Therefore, the electrodes should be polarized as long as they're in contact with the electrolyte since this will prevent corrosion. Such a polarization current will require an external power source for when the fluctuating renewable energy source is insufficient. Another option is to simply remove the electrolyte from the system when not in operation for longer periods of time [16]. These electrolysers therefore need a battery system or a grid connection, and an automatic system for removal of electrolyte in times of low power production.

1.2.1.2 PEM Water Electrolysis

PEM (Polymer Electrolyte Membranes) electrolysers are defined by a cell equipped with a solid polymer electrolyte [17]. This results in a simpler structure and no circulating liquid electrolyte. The PEM *fuel cell* technology was introduced by General Electric in the 1960s to overcome the drawbacks of the alkaline fuel cell technology (see chapter 1.3 for more on fuel cells), but PEM water electrolysis was introduced in the 1970s [18].

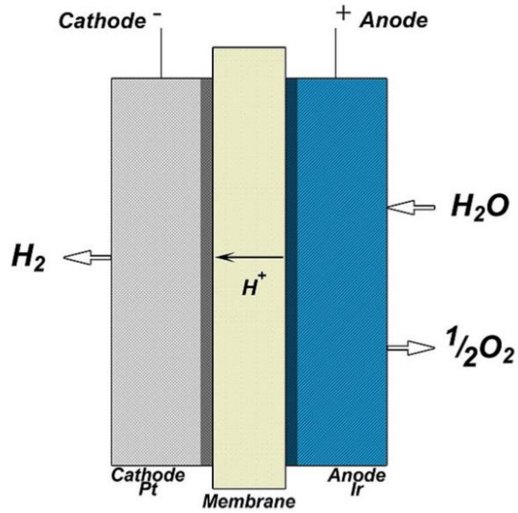

Figure 3 Schematic of PEM electrolysis [118]

The reactions at the anode (positive electrode) is:

$$H_2O \rightarrow 2H^+ + \tfrac{1}{2}O_2 + 2e^-$$

And at the cathode (negative pole):

$$2H^+ \rightarrow H_2$$

This yields the total reaction [19]:

$$H_2O \rightarrow H_2 + \frac{1}{2}O_2$$

PEM electrolysers have higher efficiency and toleration of intermittent operation but are more expensive than alkaline electrolysers and have lower production rates. However, this can be changed in the near future as PEM is expected to see great improvement and development [20] [19] [21] [14] [22]. PEM electrolysers have largely replaced alkaline electrolysers when using wind power [23].

1.2.2 Storage options

One of the key challenges for hydrogen fuel is getting cost down to the levels of traditional fuels. In order to get cost down to profitable levels it is necessary to commence large scale distribution, and effective storage is the key to enabling large scale distribution of hydrogen [24] [25]. Storage capability is hence a vital part of the feasibility of any hydrogen production. The feasibility of storage technology is determined by volumetric and gravimetric capacity, safety, cost, weight, and quality of absorption and desorption kinetics. When considering gravimetric energy density (energy per weight) hydrogen is by far the best rated energy carrier [26] [27]. However, hydrogen meet severe challenges in its volumetric density (energy per volume) (see Figure 4) [28].

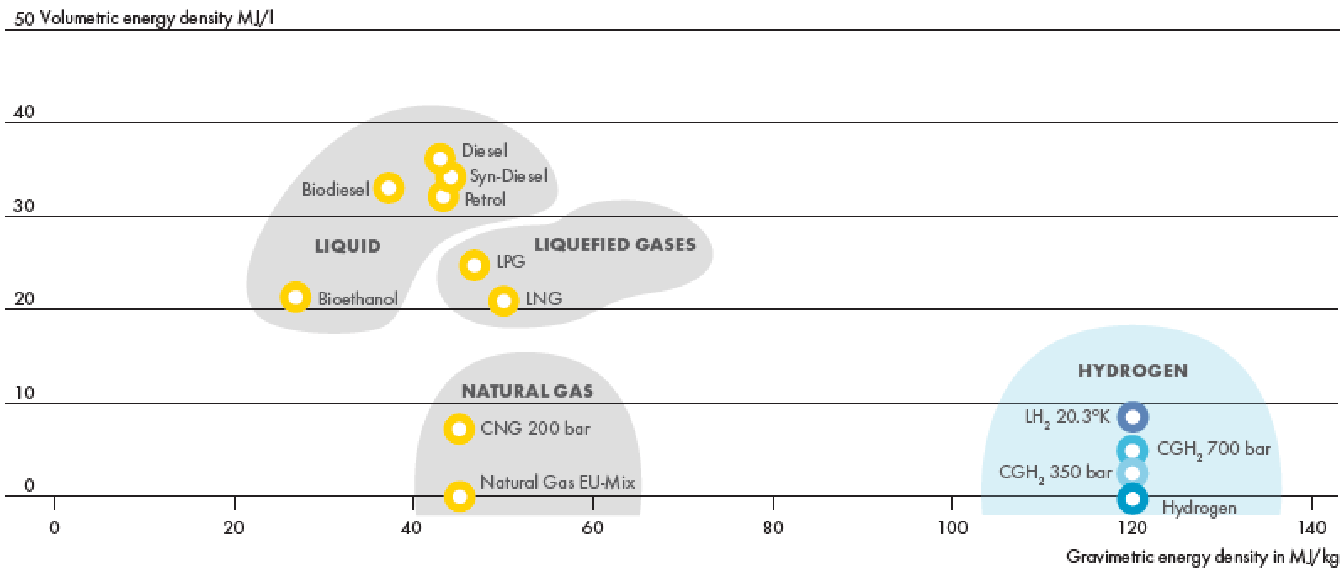

Figure 4 The volumetric and gravimetric properties of hydrogen *[16]*

The main challenge is to find a material that is able to solve three main requirements; high hydrogen storage capacity, reversibility of the discharge and charge cycle at moderate temperatures (70-100°C). Such a material will ensure that it is compatible to current fuel cells and quick charging or discharging kinetics with minimum energy barriers so that it releases and charges hydrogen as efficiently as possible [27].

There are mainly five storage technologies for hydrogen; compression, liquefaction, cryogenic compression, and physical or chemical storage in hydrids. At the moment physical storage in hydrids are unmatured technologies with the exception of in submarines, and not a viable option for Fosen [23] [29] [30]. However, this technology is probably the next technology in line reaching necessary maturity [31] [32]. Chemical storage in for example ammonia or methylcyclohexane shows great promise, but also need further development [23]. These kinds of technologies would also require an additional step to extract the hydrogen out of the chemical when reaching its destination. Cryogenic compression refers to cryogenic temperatures in a vessel that can be pressurized [33] [34]. However, only compressed and liquefied hydrogen will be investigated in this thesis as those are the only viable options for Fosen for now.

1.2.2.1 Compressed storage

In room temperature hydrogen is in its gaseous form. Due to the very low volumetric density this allows for very small amounts of hydrogen to be stored and transported (see Figure 4). Therefore, storage and transport of hydrogen gas requires compression. Usually hydrogen for transport is compressed to pressures spanning 350 to 700 bar, while stationary storage is up towards 200 bar [16]. Compression requires 9-12% of the final energy content in the hydrogen and put demands on the storage tanks' strength and durability [34].

Hydrogen also gives rise to a degradative process called hydrogen embrittlement [35]. This is of great concern when it comes to high-strength steel, titanium alloys and aluminum alloys. Hydrogen embrittlement is a type of deterioration due to hydrogen that results in corrosion-like processes which increases with hydrogen pressure and alloy strength [36] [37]. It causes reduced load-bearing capacities, cracking and potentially catastrophic stress induced failures in susceptible materials. In addition, steel is heavy, and this has given rise to tanks made of carbon fiber lined with aluminum, steel, or specialized polymers when weight is an issue [38]. Lower pressure decreases the energy need but increases the volume and thereby the amount of material. However, high-pressure tanks require more expensive materials which withstand the pressure and do not increase the overall weight too much.

1.2.2.2 Liquefaction

A possible solution to the challenge of hydrogen's low volumetric density is liquefaction. As a liquid hydrogen achieves several advantageous storage characteristics [39]. The density of hydrogen in gaseous form is 0.089 g/l. This is roughly fourteen times lighter than air, which gives hydrogen high buoyancy in the atmosphere. However, at its boiling point and at 1.013 bar hydrogen has a density of 70.79 g/l. This means that liquefaction increases the density of hydrogen by a factor of around 795. This allows for liquid hydrogen to be stored and transported in a 7-to-1 ratio compared to compressed hydrogen gas [40] [27].

Hydrogen has a very low boiling point, -252.76 °C, or 20.4K. At temperatures lower than this hydrogen is liquid under normal pressure of 1.013 bar. The state of aggregation is however not only dependent on temperature, but also pressure. Gases can be liquefied by raising the pressure. However, above the critical temperature -239.96°C hydrogen cannot be liquefied [16]. Similarly, there is a pressure limit where a gas can't be liquefied anymore. For hydrogen this critical pressure is 13.301 bar (see Figure 5).

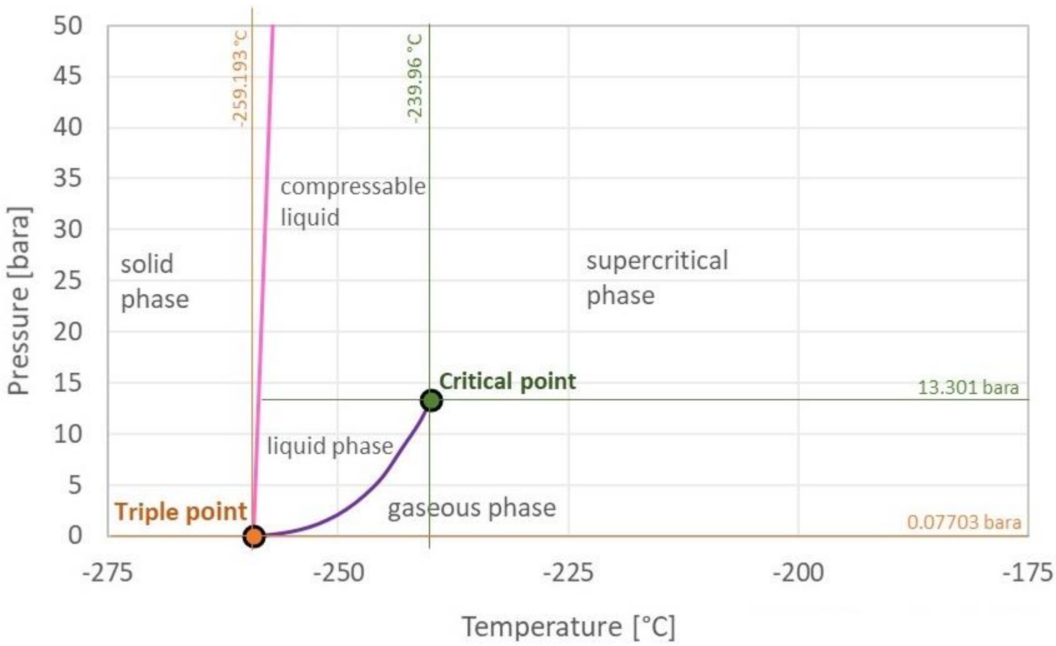

Figure 5 The phase diagram of hydrogen

Cooling to such low temperatures and keeping it there, requires energy. Liquefaction requires around 30% of the final energy in the hydrogen, compared to 9-12% for compression [16] [34] [41]. However, there are substantial potential for improvement, according to the US Department of Energy the theoretical energy demand for compression to 700 bar or its liquefaction is 4-10% [42].

Liquefied hydrogen (LH2) experiences evaporation losses of 0.1-1% per day during storage transport, and up towards 5 percent at loading [20]. This evaporated hydrogen needs to be extracted and supplied for other use or re-liquefied.

For the time being there are few liquefaction plants worldwide. In North America there are eight liquefaction plants with a production capacity of 5-10 tpd (tons per day) [35]. In total the current liquefaction capacity is 20 tpd in Europe, 30 tpd in Japan and <300tpd in North America [43].

1.2.3 Transport technology

The feasibility of hydrogen production is furthermore dependent upon the ability to transport hydrogen to its customers. There are already mature transport technologies in place. There are proven transport options ranging from 500 to 4000 kg per truck depending on the state of aggregation [44] [16]. In addition to trucks, pipeline is a viable technology. Pipelines is the best option for comprehensive and large-scale hydrogen transport [44]. However, pipelines require very high initial investments well above the expected limits for Fosen [16]. With the initial customer and production potential at Fosen in mind, trucks are the most likely transport option.

Regarding transport routes it is natural to envisage a hydrogen hub located at a harbor in order to easily distribute hydrogen to marine activities. This is vital as it is likely that most of the hydrogen consumption in the near future will be ferries and speedboats. In addition, companies like Kawasaki are developing large transport ships for hydrogen and this could provide an export potential in the future [45]. Furthermore, Trondheim represents a very advantageous location for hydrogen production due to being centrally located in Norway with well-developed infrastructure both to the north and the south, a strong industry and being the technological capital of Norway. Trondheim and its surrounding areas are to that end well suited for hydrogen transport.

1.3 Fuel cells

The energy producing chemical reaction described in equation (1) occurs in fuel cells. Fuel cells are more or less the opposite of an electrolyser, consuming hydrogen to produce water and electricity, electricity of course being the target resultant. There are basically five types of fuel cells; alkali, Molten Carbonate (MCFC), Phosphoric Acid (PAFC), Proton Exchange Membrane (PEM) and Solid Oxide (SOFC) fuel cells [46]. Every fuel cell has two electrodes (the anode and cathode), where the chemical reaction that produce electricity occurs, and an electrolyte, which carries charged particles from one electrode to the other and a catalyst which accelerates the reactions [46].

The produced electricity can then be used to power a range of vehicles and equipment. Fuel cell cost and viability are outside the scope of this thesis but the technology was presented shortly here to give an introductory basis for any reader.

1.4 Wind power

Wind power is a cost-effective way of producing clean, sustainable electricity [47]. This electricity can be used to produce hydrogen by for instance alkaline or PEM electrolysers. The functional description of producing a gaseous energy carrier from electricity is called power-to-gas [48].

1.4.1 Power-to-gas

Wind power will by nature fluctuate. As mentioned briefly in chapter 1.2.1, electrolysis requires a fairly stable power supply and few shutdowns to guarantee a hydrogen of sufficient purity. Hence, a wind powered hydrogen production gives rise to mainly three strategies to fulfill the system requirements. Either the electrolyser must be of a type which copes with shutdowns without degrading the quality of the hydrogen, and then be turned off as soon as the power production is below the rated power (Figure 6), or it needs to be grid or battery-assisted in order to keep the electrolyser running (Figure 7 and Figure 8). Such a grid-assisted arrangement can keep the electrolyser running the entire year but will introduce grid-rental costs, put restrictions on the location of the production unit and require extra equipment. A battery installment will require extra expenses due to battery equipment and probably increase the maintenance cost. Grid assistance or a sufficient battery will ensure that electrolyser efficiency and hydrogen production is maximized by keeping the electrolyser power at its required level at all times, and the electrolyser is subjected to less stress *[49] [50]*.

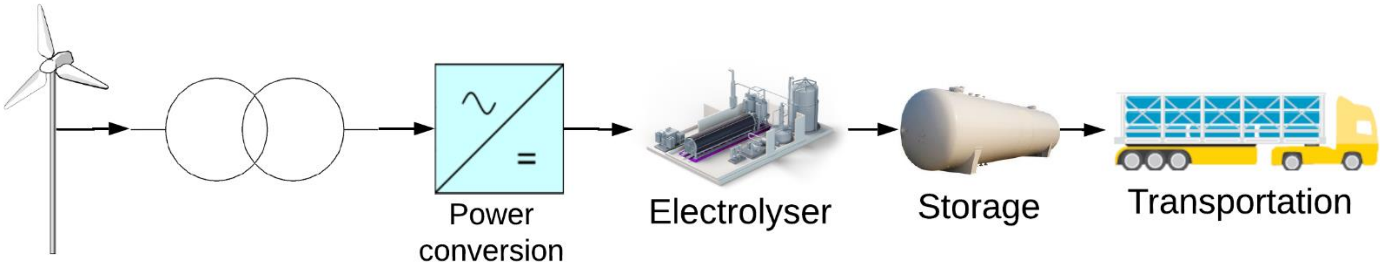

Figure 6 Stand-alone hydrogen production, adapted from *[51]*

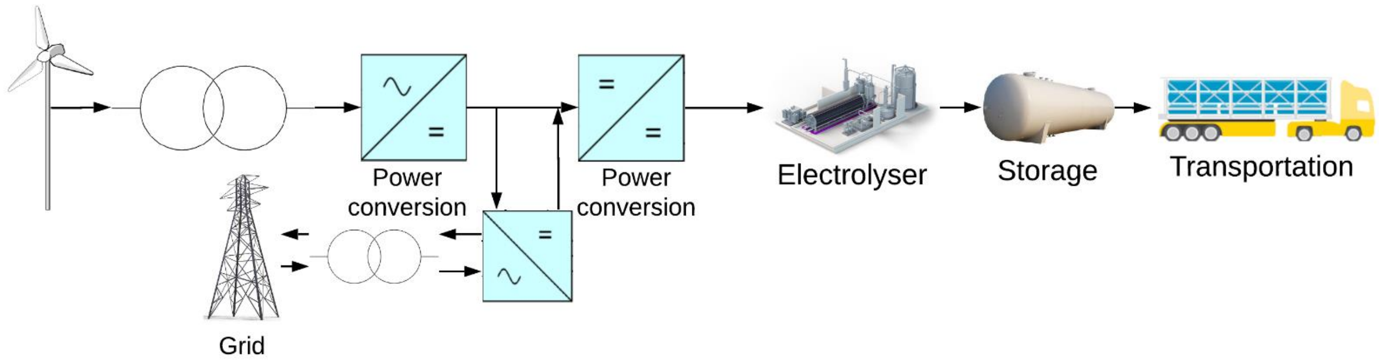

Figure 7 Grid-assisted hydrogen production, adapted from *[52]*

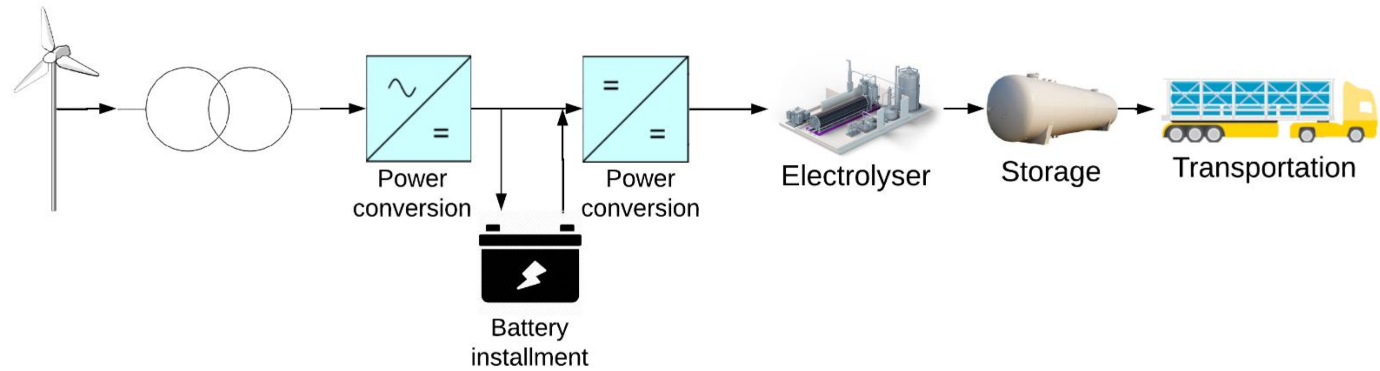

Figure 8 Battery-assisted hydrogen production

1.4.2 Project examples

There are several projects working on producing hydrogen through wind power. Two of these projects are in Norway and will be presented shortly here.

At two farms in Byneset, Trøndelag, an EU-financed pilot project is investigating the potential for storing excess wind power as hydrogen gas. The hydrogen will function as a battery, capable of powering the farms in times of little wind. As a part of the EU project REMOTE, Byneset will provide valuable experience and data for the kinds of operation one can envision at Fosen [53].

Further north, at Raggovidda wind park in Finnmark county, another EU project is experimenting with the combination of wind power and hydrogen production. HAEOLUS is a project that will develop and test new technology for production hydrogen by wind power. A 2.5 MW PEM electrolyser will produce hydrogen in Berlevåg municipality as a combined experiment between Varanger Kraft, UBFC, Hydrogenics, Tecnalia, UniSannio and KES as partners. The project will finish in 2021 [54].

These projects show that hydrogen is coveted by several industrial actors, and Norway is attracting foreign interest and investment.

1.4.3 Fosen Wind park

Fosen wind park is constituted by six wind farms in Trøndelag County; Storheia, Geitfjellet, Harbaksfjellet, Hitra 2, Kvenndalsfjellet and Roan (see Table 1).

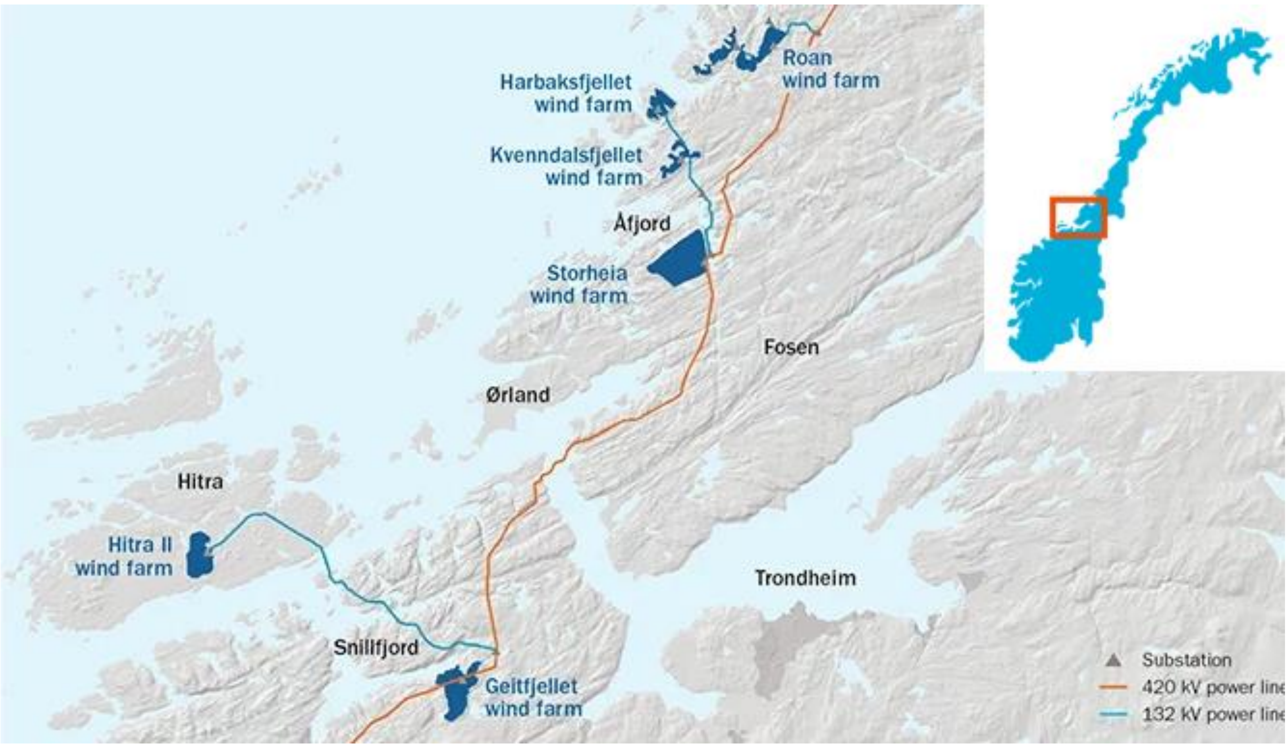

Figure 9 A map of Fosen wind park

When the construction is completed in 2020 Fosen Wind Park will be the largest onshore wind power facility in Europe. The six wind farms will consist of 277 wind turbines with an installed capacity of 1057 MW (~1 GW) and production of 3.6 TWh. The park will use Vestas V117-4,2MW and 3,6MW wind turbines. The company Fosen Vind is owned by the power companies TrønderEnergi and Statkraft, and the European investment consortium Nordic Wind Power DA [55].

Wind park	Municipality	Installed effect [MW]	Production [GWh]	#Wind turbines	Turbine type [MW]
Storheia	Åfjord and Bjugn	288	1000	80	4.2
Geitfjellet	Snillfjord	180.6	548	43	4.2
Harbaksfjellet	Åfjord	136	443	30	3.6
Hitra 2	Hitra	93.6	290	26	3.6
Kvenndalsfjellet	Åfjord	113.4	405	27	4.2
Roan	Roan	255.6	900	71	3.6
Sum		**1067.2**	**3586**	**277**	

Table 1 Fosen Wind Park

In other words, "Fosen Vind" contains six wind farms, where two are not located within the Fosen district itself. Despite that, throughout this thesis the entirety of Fosen Wind (all six wind farms) is referred to as Fosen, unless stated otherwise.

1.5 Definitions

CAPEX (capital expenditures) are the funds used to acquire, upgrade, and maintain physical assets such as property, technology, equipment, or buildings. In other words, CAPEX is the type of expense which shows on the balance sheet as an investment and cannot be deducted from income for tax purposes [56] [57].

OPEX (operating expenses) are short-term expenses required to pay for the ongoing operational costs. Unlike CAPEX, OPEX can be deducted on the company's taxes in the same year as the expenses occur [58]. Despite several scientific articles dividing non-CAPEX cost into operational and maintenance cost (O&M) this thesis will include maintenance cost in OPEX since maintenance is a part of the annual operating expenses. In addition, several of the sources used for CAPEX and OPEX data included maintenance in the OPEX information [57].

Chapter 2 Methodology

In this chapter the structure, data material and methodology applied in this paper is presented. First the structure of the entire thesis is described, then the data and associated assumptions, and lastly the calculation method is described.

2.1 Basis

This thesis is based on the wind power project Fosen Wind described in chapter 1.4.3. The hydrogen production capacity is based on technical and economic information regarding three different electrolyser options, two alkaline and one PEM electrolyser (see Table 2).

	Type	Size [MW]	Production rate [kg/d]
Electrolyser A	Alkaline	2.3	1000
Electrolyser B	Alkaline	6.8	3000
Electrolyser C	PEM	2.02	804

Table 2 Electrolyser options

These electrolysers will be the basis of CAPEX and OPEX calculations which will be used to describe the total cost and per kg cost of a potential hydrogen production at Fosen.

Scope of this thesis:

The scope of this thesis is determined by a finite length of time which allows for calculation of CAPEX and OPEX. This scope should be a sufficiently long period of time, representative for the equipment and technology in question. It is natural to use the lifetime of the electrolysis equipment as a basis. This allowed for calculating OPEX costs for every year and adding them up to a total cost. That scope is researched and presented in chapter 3.1.

Type of system:

This thesis will use a stand-alone system without connection to the grid or batteries as a basis (see Figure 6). That was a necessary simplification regarding calculating cost for different options. Furthermore, a grid-connection would introduce grid fees which would be detrimental to any advantages of Fosen. However, a battery installment is included in CAPEX calculations. But this battery is meant to safely power down alkaline electrolysers in times of insufficient power production, not keep the electrolysers running in times of insufficient wind.

2.2 Data and sources

The data used in this thesis are mainly from scientific articles found using Science Direct and Google Scholar and through the bibliography of the articles themselves, and information supplied by market actors. The hydrogen industry is developing fast, is relatively small, and produces few unit sales and requires large investments. This makes companies very restrictive on what information they're willing to share as any market advantage is vital. Several market actors were contacted, and some shared information about vital parts of the hydrogen production chain as long as they were anonymized.

It is generally unfortunate to use anonymous sources but it would not be possible to reach a reliable answer to the research question without that information. In a rapidly growing industry with few but large contracts the market actors want to keep their cards close to the chest. A feasibility study like this one requires more detailed information about cost and performance than what is available to the general public. This weakness has been addressed by finding several comparative data sets which enables quality checking the data and calculations an putting the results into perspective (see chapter 4.3). It is worth noting that most of the data about CAPEX and OPEX are only a few months old and should therefore be representative of the current market.

The processing of the data was done through a combination of Microsoft Excel and MATLAB. Excel provides the opportunity to make large spread sheets which allows for an orderly calculation of every step in the value chain of hydrogen production, storage and transportation. MATLAB allows for more complicated operations.

Unit conversions:
This report builds on a multitude of sources using many different units. All conversions of scientific units were done using a conversion table from Universal Industrial Gases, Inc [59]. All currency conversions were done using currency rates on February 19th, 2019.

2.3 Assumptions regarding data

In addition to the need for using anonymized sources it also quickly became apparent that in order to complete this thesis several assumptions and simplifications would be necessary as companies were not willing to share *all* vital information, anonymously or otherwise. Furthermore, several aspects of a feasibility study like this will always need assumptions and simplifications as not all information is available and due to limited time before the deadline. Those assumptions will be presented in the following sub-chapters.

2.3.1 Data for Bessakerfjellet

As Fosen wind park is under construction there are no data for the actual power production. To investigate the production at Fosen it was assumed that the percentage production relative to the installed capacity at Bessakerfjellet is representative for the six wind farms at Fosen Wind. Bessakerfjellet is a wind farm of a similar size to those at Fosen, and at a geographically similar location. This data from Bessakerfjellet provided by TrønderEnergi will give insight into the conditions than can be expected at the six wind farms at Fosen. Bessakerfjellet vindpark is in Roan municipiality, a few km north of the Roan wind farm seen on the map in Figure 9. It was constructed in 2008 and consists of 25 wind turbines of a combined installed capacity of 57.5 MW (2.3 MW each) [60].

The data sample provides production data for every hour, of every day from January 1st, 2009 until June 23rd, 2016 at 9 AM. That is 65 528 data points over 2641 days, or 7.23 years. To make comparable data for each month the remaining months of 2016 is the average of the rest of each corresponding month in the period 2009-2015. It was assumed that the wind conditions will be generally similar for the Fosen project, and that the data sample will provide insight into the fluctuating conditions and potential at Fosen. Through this assumption it was possible to calculate the number of days one can expect reaching a threshold power production. The percentage of the total potential production is assumed to reflect the future percentage production at the wind farms at Fosen. This removed the need for using for example a Weibull distribution in order to emulate the stochastic wind conditions as often is the preferred strategy in literature [61].

2.3.2 CAPEX and OPEX data

The CAPEX and OPEX data for PEM and alkaline electrolysers were from several suppliers and scientific articles, and for different electrolyser sizes and with different equipment included in each option. That means that assumptions regarding how the cost for one part of a production technology translates into an equivalent part of another production technology was necessary. This was the most reliable way of estimating the cost of the total system including all essential expenditure and ensure that one compares "apples" with "apples". The assumption about the relation between different cost categories for different technologies is explained during the calculation to increase the readability of the text.

2.4 Procedure for calculating cost

The electrolyser options which constitutes the basis of this thesis, available data and the assumptions regarding Bessakerfjellet combines into calculations of the economic characteristics of hydrogen production, storage and transport at Fosen. That procedure will be described in the following sub-chapters.

2.4.1 Cost of production

The three electrolyser options presented in Table 2 have the following relevant technical data:

	Type	Production rate [kg H2/day]	Installed capacity [MW]
Electrolyser A	Alkaline	1,000	2.3
Electrolyser B	Alkaline	3,000	6.8
Electrolyser C	PEM	804	2.02

Table 3 Technical information about alkaline electrolysers

For the equipment that was relevant for both types of electrolysers but where the data only was available for one option it was assumed that it would increase and decrease linearly with the production size for both electrolyser types. This assumption was used for information regarding for example the cost of storage and buffer tanks, installation, cables and pipes, and building plot. This is not strictly speaking true for storage tanks, as many storage tanks are spheres. The surface area A of spheres is $A= 4\pi r^2$ and the volume V is $V=4/3\pi r^3$. Which means that a doubling of the radius increases the volume eightfold. While a doubling of the radius only requires a fourth fold increase in the surface area. However, the exact cost development is determined by the shape and type of storage [62]. There are many different shapes of storage equipment and it is outside the scope of this thesis to determine which to use [63]. Since CAPEX of storage tanks are mainly made up by the materials used, which is directly linked to the size of the tank, a linear cost increase with size is assumed [64].[3]

The operation of an electrolyser will with time reduce its efficiency and be detrimental to the production rate. In this thesis the hydrogen production is assumed to be constant every hour, of every day it is turned on, throughout the expected lifetime of the equipment. This is not completely accurate. It is more likely that the production rate will decrease with time and thereby increase the per kg production cost. However, no information on that rate was found during the research stage and hence the production rate is assumed constant.

[3] It is also important to be aware that hydrogen do not behave as an ideal gas, and one can't assume a linear relationship between mass and pressure for a given volume of hydrogen [85].

The CAPEX was assumed to only occur at the beginning of the project while the OPEX is evenly spread across the lifetime of the project. The cost will be presented at a per kg basis to allow for easy comparison with other source material. This value is called the levelized cost of hydrogen (LCOH) and is inspired by the levelized cost of energy (LCOE). The levelized cost of energy (LCOE) is a measure that allows for comparison of different sources of electricity or power. Hydrogen is an energy carrier hence LCOH can be used to illustrate the comparative costs between the different production methods. The levelized cost it the value of which a fixed revenue level throughout the project's lifetime will cause the project to break even [65].

That gives the following formula

$$LCOH = \frac{sum\ of\ costs\ over\ lifetime}{sum\ of\ energy(H_2)\ produced\ over\ lifetime} = \frac{TLC}{\sum_{k=0}^{n} \frac{E_g}{(1+r)^k}} \tag{2}$$

$E_g = amount\ of\ hydrogen\ produced\ [kg]$

$n = lifetime\ [y]$

$r = discount\ rate$

TLC is an abbreviation of Total Levelized Cost. It is the total cost of the plant including CAPEX and OPEX [11]. The discount rate r is a risk adjusted requirement that is used to calculate the present value (PV) of future cash flows, it accounts for the time value of money, the risk of the project and inflation. It also reflects the return capital owners expect to achieve on the capital they've invested. In accordance with Parra & Patel (2016) it was set to 0.08 [11]. Assuming that all CAPEX is included in the construction of the plant the formula is [11]:

$$TLC = CAPEX + \sum_{k=1}^{n} \frac{OPEX}{(1+r)^k} \tag{3}$$

The presentation of total cost and cost per kg will be on the basis of TLC and corresponding LCOH (see chapter 3.6).

2.4.1.1 CAPEX:

The information about CAPEX for the two electrolysis technologies were from different suppliers and didn't include the same expenses. In order to compare this data, it was hence necessary to include all relevant data in both technologies and assume a linear relationship between them.

The information about *alkaline* electrolysers included *Cost* (buying the equipment; including the electrolyser, all necessary equipment for intake of pure water and high-voltage power to the electrolyser, low voltage power to the control panel, and engines and pumps for producing clean and compressed hydrogen), the *Foundation and building*, *Installation of equipment* (including cables and pipes) and *Building plot*.

The CAPEX data for *PEM* electrolysers on the other hand, included *Cost* (buying the electrolyser generating hydrogen at 20 bar, equipment for power conversion, one-year maintenance and warranty), a *Buffer tank* (20 bar and 2m^3 internal volume[4]) and a *Compressor* (250 bar and 20 feet ISO container). For PEM electrolysers the CAPEX and

[4] A 2m^3 tank will hold around 2.5 kg of hydrogen gas [86]

OPEX data were given without VATs included. The relevant costs were therefore increased with 25 percent in accordance with [66].

This resulted in CAPEX including the following categories:

- Cost
- Foundation and building
- Installation of equipment
- Building plot
- Battery back-up
- Compressor
- Buffer tank

The column marked "Cost" includes all essential equipment including intake of clean water, high-voltage power to electrolyser, low-voltage power to control panel, motors, and pumps for cleansed hydrogen. Power conversion equipment is not on the list above despite being a usual expense as it is included in the "Cost" of both electrolyser technologies. Furthermore, it is assumed that costs related to scrubber, deoxidizer and dryer is included [67]. As the alkaline electrolyser included the necessary equipment for making clean and "compressed" hydrogen it would seem that some sort of compressor is included. In the PEM electrolyser this is also included for 20 bar. As much higher pressures are needed, a column for compressors is nevertheless also included in the CAPEX calculation.

The expenditure associated with the foundation and building, and building plot will increase linearly with the size of the building and plot, which is assumed to increase linearly with the production size. That is due to the fact that the alkaline and PEM electrolysers have similar areal footprint (~1 m2/Nm3 H2 [68]), and the cost of construction is affected by material and man hours not electrolysis technology.

The information about installation cost for the PEM electrolyser was given as a package including commissioning and training of personnel. For the alkaline electrolyser installation was given alone, but to a much higher cost than installation, commissioning and training for the PEM electrolysers. This makes it difficult to compare the two. It was assumed that commissioning and necessary training of personnel for the alkaline electrolysers is contained within the other costs, and therefore negligible. The column called "installation" therefore represent the info called "installation, commissioning and training" for the PEM electrolyser, and "installation including cables and pipes" for the alkaline electrolysers. But since the PEM-related cost was significantly less than alkaline (690,000 NOK for Electrolyser C, 2.5 MNOK for electrolyser A) it could hint to the expense related to cables and pipes being quite large. However, it seems unlikely that the PEM supplier would not inform of those costs, and the difference could hence be due to PEM simply being easier and cheaper to install (which coincides with chapter 1.2.1.2). It consists after all of less liquid and moving parts. Installation cost of the PEM electrolyser was hence assumed to be sufficiently covered with only the info supplied by the market actor.

The information for expenses related to batteries are for a battery installment of 550 kWh and 500 kW. It is assumed that this is sufficient for these electrolyser options, or at least a cost at the right order of magnitude. Market actors have not shared information about what kind of batteries that are needed or give information that can allow for this calculation. Be aware that these costs only are relevant for alkaline electrolysers as they need back-up power at shutdowns and are not meant to increase the operation time. The operation time of the electrolysers will still be determined by the wind power production.

It was further assumed that the cost for the compressor will be very similar for the alkaline and PEM electrolysers respectively as the compressor cost is not affected by the source of hydrogen. The information regarding cost for compressors was for an example at 3.6 MNOK for at 250 bar with a capacity of 7.5 m^3/min. This is assumed to mean that it can transform 7.5 m^3 of hydrogen gas per minute at the pressure it is at when leaving the electrolysers to 250 bar. 7.5 bar at 1 atm is 0.626 kg H_2 [69]. That yields around 900 kg per day. The research for a comparison in order to know how different sizes affect the cost has not been fruitful. However, the cost seems realistic as Gruger et al. (2018) operate with an almost identical cost for a similar compressor [70][5].

Greiner et al. (2006) operate with an investment cost for compressors of 700 €/kW [71]. This would entail a cost of 13.6 MNOK for Electrolyser B and hint to compressors cost being fairly linear with capacity. To adjust the compressor cost it is assumed a linear relationship with the daily production rate and the aforementioned compressor example. Hence, the compressor cost is set to 4, 12 and 3.22 MNOK for the electrolyser options respectively. This also fits nicely with the cost from Greiner et al. (2006), and considering that data being over a decade old it is reasonable to expect today's prices being lower than what Greiner reported.

In chapter 1.2.2 the storage options are investigated. There are mainly two options, compressed and liquefied[6]. Almost all hydrogen consumption is based on compressed hydrogen. Hence the cost for a compressor is included in the base case and not subtracted for the liquefaction option as it would be part of a hydrogen investment anyway.

The buffer tank is a small 20 bar storage tank. This cost could be removed, as storage cost is calculated later. But it was decided to keep that cost as it could be technical benefits for a small buffer tank that hasn't been pointed out explicitly by the supplier [67]. It is assumed a linear relationship between increasing size and cost due to increased material use. Chapter 3.4 will investigate cost related to storage more in depth. This buffer tank was included in one of the examples' pricing, and so it was included here as it provides insight into tank cost. The installation of cables and pipes are assumed to increase linearly with the increasing production.

2.4.1.2 OPEX:

Just as for the CAPEX the information about OPEX also contained different categories for each electrolyser option as it originated from different suppliers which didn't necessarily include the same expenses. In order to compare this data, it was hence necessary to include all relevant data in both technologies and assume a relation between them. In total the OPEX include the following categories:

- Maintenance, including replacement of cell-stacks
- Cost of water
- Cost of electricity in hibernation mode
- Cost of electricity in operation mode

In accordance with formula (2) and (3) the OPEX for the electrolysers is calculated for the entire lifetime assuming 365.25 days per year to include leap years. While the data for alkaline electrolysers explicitly included replacement of the cell-stacks in the maintenance cost the data for *PEM* electrolysers did not specify whether stack replacement was included.

[5] Gruger et al.= 3.8 MNOK, example = 3.6 MNOK (see Table 8)
[6] There are other options, like chemical storage in ammonia or in hydrides but they are too immature technologies to be realistic options [29].

Communication with several market actors revealed that maintenance cost for *alkaline* electrolysers will typically be 1.5- 2 percent of CAPEX over a 15-20-year period, including replacement of cell stack (usually after 8 to 10 years) [72] [73] [11]. To avoid calculating too low OPEX cost the assumed OPEX cost was set at 2 percent of CAPEX. Since the maintenance cost for *PEM* electrolysers were significantly higher than for alkaline it is assumed that replacement of cell stacks is included in the maintenance cost for PEM electrolysers as well.

Electrolysis require two inputs, water and electricity. Water consumption for alkaline electrolysers is around 10 liters per kg, and around 20 liters per kg for PEM electrolysers [15]. The cost of water varies from municipality to municipality. The cost for each of the municipalities is averaged in order to avoid the need for calculating every cost for each location as the exact location is outside the scope of this thesis. There is a one-time fee in several municipalities, annual fixed price for water and drain, and a varying cost per cubic meter water and drainage. Since the electrolysis consumes the water it will not be need for a large drainage system, and this cost is assumed to be negligible. The water cost will be therefore be calculated by the one-time fee, the annual fixed price plus the varying price times the amount of water consumed.

Water cost was calculated by finding each municipality's pricing for water and drainage. The five municipalities include different fees, and some are of significant different magnitude. Hence, a dataset with the cost from each municipality was created to find the average cost. The cost of water over a lifetime of 15 years is divided into a one-time fee, a fixed annual cost and a varying cost determine by water consumption.

Municipality	**One-time fee [7][NOK]**	**Fixed price [NOK/y][8]**	**Varying price [NOK/m3]**
Åfjord [74]	12500	3380	19.95
Snillfjord [75]	45 245 – 129 625 [9]	(11 095 – 44 740) + 1560	12.40
Bjugn [76]	~11400	6730 or 16790 [10]	12.30
Hitra [77] [78]	16897.75[11]	8218.75+1644.8+822.4 *2+76395[12]	16.91
Roan [79]	18000	2500	11
Average	**14699.4**	**11725.75**	**14.5**

Table 4 Water cost by municipality

In some municipalities the costs are much higher than in the other municipalities, and some of these costs are consumption specific up to a certain maximum price. Since these calculations are to be representable of an average electrolyser installment and be subject

[7] Subscription fees

[8] Cost for water gauge (rent), supervision and reading fee, annual subscription fee at Hitra

[9] Only the minimum and maximum connection fee is listed. Since this is well above all the other fees, it is excluded from the calculation of average cost

[10] The latter price is used if consumption is >10000 m^3. The cost is 6730 for a consumption between 1000 and 10000 m^3. Only electrolyser B will exceed 10 000 m^3 per year

[11] The one-time fee for connecting to the water supply is determined by the diameter of the pipe.

[12] Subscription fee for water consumption exceeding 5400 m^3/y, since this fee is well above all others it is exempt from the calculation of average

to multiplication when installing several electrolysers these costs were exempt from the calculation of average cost.

The feed water cost is then calculated by the formula

$$\begin{aligned} Water\ cost\ [NOK] \\ &= \text{"}One - time\ fees\text{"}\ [NOK] + \sum_{k=1}^{n} \frac{Fixed\ price_k\ \left[\frac{NOK}{y}\right]}{(1+r)^k} \\ &+ \sum_{k=1}^{n} \frac{varying\ price_k\ \left[\frac{NOK}{m^3}\right] * water\ consumption[m^3]}{(1+r)^k} \end{aligned} \tag{4}$$

Despite the water cost having some CAPEX costs, they all included in the OPEX cost to avoid confusion.

Alkaline electrolysers have an aqueous electrolyte, usually potassium hydroxide (KOH). This electrolyte is included in purchase of equipment, and potential replacement costs are reported to be negligible. In addition, cooling water and nitrogen is needed in case of full stop. This is however not consumed, and costs related to the electrolyte and cooled nitrogen are also reported to be negligible.

Electricity constitutes the main cost of electrolysis and the main expense regarding OPEX is electricity costs, and the largest consumer are the electrolyser stacks [7]. Other energy consuming components include power conversion electronics, water circulation, gas purification system, ventilation, assorted valves and control systems. Since the electrolysis is powered by TrønderEnergi's power production and hydrogen production by electrolysis is exempt from electricity tax in the 2019 state budget, only production costs are relevant [20] [80]. Grid rental costs are therefore not included, and this represents a substantial saved expense. To calculate the cost of electricity a projected electricity price from TrønderEnergi for the next ten years were the basis. The price of electricity for the period of analysis has been set to 0.32 NOK/kWh. This is the average of projected electricity prices for the time period 2020-2029 (see appendix A). However, in chapter 3.7 the cost with an electricity price varying from 0.26 to 0.80 NOK/kWH is presented in order to provide a perspective of the importance of electricity price.

In hibernation an electrolyser has a very low power consumption, limited to frost protection and control systems. The consumption will be dependent upon environmental conditions but 5kW is reported to be an indicative number. This number is for a PEM electrolyser of 2 MW, but it is assumed that this is linearly representative for alkaline electrolysers as well by looking at the ratio of H_2 production (see Appendix J).

By also assuming that switching the electrolysers on and off is instantaneous (no transition period, see Figure 10), and don't require additional power, calculation of the power consumption the entire year was possible by multiplying consumption with time.

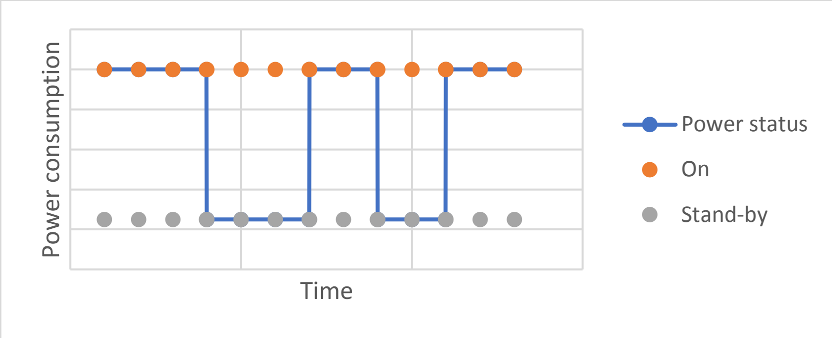

Figure 10 Assumed power fluctuation when switching electrolysers on/off

2.4.2 Cost of storage and transport

The cost of storage is directly linked to the required size which is directly coupled with the transportation rate. Therefore, the methodology of calculating the cost of storage and transport will be presented together in this chapter. However, it will be divided into compressed and liquefied.

It is assumed that some temporary storage capacity must be in place for TrønderEnergi to operate a hydrogen production facility. In addition, a more centrally placed storage facility close to a harbor seems like the natural strategy to easily reach marine customers. This strategy would entail a smaller storage facility at the production facility and a larger centrally located storage facility.

However, there is some regulatory legislation which affects the localization of a storage facility. Large scale hydrogen storage would be within *Regulations of major accidents* ("Storulykkeforskriften") [81]. For amounts up to 5 tons hydrogen it is defined as *notifiable business* ("Meldepliktig virksomhet"), which means that the operation will be dealing with article 6. That article requires reports every third year, areal planning and emergency response measures and must secure prudent distance to the population around the major accident activity, control of the surroundings around existing major accident activity and proper distances in establishing new major accident activities and changes in existing major accident operations [82]. This is the municipality's responsibility to oversee.

Furthermore, if the amount exceeds 5 tons and is below 50 tons it will fall under article 9. This defines the business as a *mandatory security report notifiable business* ("Sikkerhetsrapportpliktig virksomhet"). This requires reporting every year and requires application in accordance with building codes ("Bygningsloven") and the general public has a saying. In other words, medium to large scale storage of hydrogen can be quite challenging judicially.

The larger centrally located storage facility would hence require several assessments outside the scope of this thesis. The costs related to the larger storage unit is subject to so many expenses and considerations in addition to the sheer storage tank that it is outside the scope of this thesis to calculate it. The storage cost calculation in this thesis is hence limited to the smaller storage unit at the production site, which stores hydrogen to distribute to scheduled trucks. But transportation cost is coupled with distance and it is therefore necessary to find feasible central storage location to exemplify the distance. Brattøra is an especially well-suited hydrogen hub in Central Norway due to it being the start of the Northern Railway Track, and a speedboat and ferry center with a well-developed harbor. Since Brattøra is in an industrial area close to the general public storage of amounts exceeding 5 tons seems difficult. If the production is to be so large as to demand a storage above 5 tons, there would therefore be need for finding another storage facility close to a harbor. However, whether the hydrogen hub is located at the production site, a near harbor or somewhere similar or finding the exact location of the storage facility is outside the scope of this thesis. As I've been able to obtain the costs of transport for several transport routes ending at Brattøra this will serve as a basis for further calculations despite there being some potential legislative issues concerning storage as mentioned earlier. Hence, the transport cost is based upon the trucks transporting its cargo from the production site to a storage facility to Brattøra.

2.4.2.1 Compressed:

CAPEX:

The cost of hydrogen storage is threefold; the costs of constructing the storage facility (1), the costs of the utilities needed to operate it and their operation (2), and maintenance costs (3) [83]. These three categories will be included in the CAPEX and OPEX calculation.

The cost of construction (1) is assumed to mainly be determined by material and labor, and both are determined by size. The necessary size of the storage facilities is dependent on multiple factors; the on-site production, consumption rate and corresponding transport rate. Due to requirements for material properties and operating costs, large scale storage of gaseous hydrogen is usually not stored at pressures exceeding 100 bar in aboveground tanks and 200 bar in underground storage [83].

Storage tanks used in FCEVs (Fuel Cell Electric Vehicles) store hydrogen at 700 bar. But such pressures are too expensive for large scale storage as they need advanced vessel materials, for instance carbon fiber, and more expensive compressors [84]. As there are no natural underground storage options, containers are the only solution. There is little to gain by burying them as space probably won't be an issue[13]. The benefits of burying them are space saving, protection against physical damage and weather, but the disadvantage of extra cost and troublesome inspection is assumed to outweigh this solution [83]. This leaves an approximate storage pressure of 100 bar.

It is also important to be aware that hydrogen do as mentioned in 2.4.1 not behave as an ideal gas, and one can't assume a linear relationship between mass and pressure for a given volume of hydrogen [85]. That means that a doubling of hydrogen pressure won't necessarily double the mass of hydrogen stored. This fact does however not affect the change in cost due to increasing size of the tank, only the amount of hydrogen contained in it. At 100 bar the volumetric density is 6.98 kg/m^3, calculated by using the density ratio expressed in appendix B [86].

To avoid accumulation of hydrogen at the production site the transportation must at least equal the production. There are several options for transportation schedules and corresponding requirement for hydrogen storage. Either the tanks can be bigger in order to allow for transportation only in the day, or they can be smaller and demand more trucks and routes evenly spread through the day. This optimization is outside the scope of this thesis. Hence, it is assumed that the trucks will transport hydrogen at equally spaced intervals of the day without including potential cost increases due to work outside normal work hours. Which is to say that as soon as a truck-load of hydrogen is produced a truck

[13] However, with the recent protests and vandalism against further wind park construction at Frøya it could be that burying storage containers to minimize visibility is necessary [182] [183] [184]

is scheduled to transport it. However, this would put a cap on the storage size. The storage size will only be as large as the truck loads require, and larger production rates would hence increase the transport cost and not the storage size. Furthermore, it seems unreasonable to use the trucks themselves as storage tanks as that would entail the truck and truck drivers being stationary at the production site throughout the production.

To find a reasonable truck frequency it is necessary to find a reasonable truck-load. An effective way of illustrating the weight capacity of hydrogen is by expressing the ratio of mass of hydrogen to the entire tank. Weight percentage (wt%) is the weight fraction of a substance within a system to the total mass of the system. How much of weight of the total system, do the desired content constitute?

$$wt\% = \frac{weight_{hydrogen}}{weight_{storage\ system}} * 100 \tag{5}$$

Volume percentage (v%) is the weight fraction for a substance within a system to the volume of the system.

$$v\% = \frac{weight_{hydrogen}}{volume_{storage\ system}} * 100 \tag{6}$$

Several storage container manufacturers state the weight and cargo capacity of their containers on their websites and it is therefore possible to make a data set of normal wt% values. With that data set as basis it is possible to estimate how much hydrogen than can be expected stored in each container.

By using the values for wt% and v% it is possible to calculate the number of truck routes needed to transport a daily production. Through that number the transport cost can be calculated by finding the average cost for a route of a given distance.

The costs attached to transport is determined by driving distance, salary, fuel cost and other OPEX [7]. To calculate the transport costs the costs for different routes are aggregated into one average km-container-cost. This lowers the precision but was necessary as there are many possible locations for the production facility.

2.4.2.2 Liquefied:

To calculate the liquefaction cost a literature study was conducted. There are very few sources on liquefaction costs, so several assumptions had to be made for a data set to be developed.

The cost of liquefaction will be significant as it requires large amounts of energy to reach the required temperatures. Furthermore, these costs will benefit greatly of large-scale implementation. Since the electrolysers this thesis is based on have different production rates it is necessary to find a relation between production rate and liquefaction cost.

As mentioned, the present hydrogen market is generally speaking dominated by few units sold at a large unit cost. Marked actors are therefore very careful about what data they publish and share. To increase the reliability and validity of data several sources were needed. Direct communication with market actors, several conference presentations and peer-reviewed articles helped contribute to establishing a data set that through the use of some assumptions allow for a calculation of liquefaction cost. This data is not divided into

CAPEX and OPEX but yield a total cost on a per kg hydrogen basis and are used to make a data set of liquefaction cost for different production rates. The data set was then used to extrapolate an expression for the liquefaction cost as a function of production rate. The calculation is explained in chapter 3.3.2.

2. 5 Functional unit

A functional unit is the quantified description of the performance requirement that the product system fulfills. In a comparative study, the functional unit is the same for all the compared systems [87]. In this thesis three separate hydrogen production systems are defined by three different electrolyser options. The functional unit for these systems is defined as 1 kg of hydrogen produced and delivered to Brattøra.

Chapter 3 Results and discussion

Chapter 3 will present the costs related to production, storage and transport of hydrogen, the effect of a changing electricity price and larger production rates.

3.1 Lifetime of electrolysers

To proceed with an analysis of cost it is necessary to declare which scope the thesis operates with. Furthermore, calculations of OPEX require and finite length of time in order to find expected annual cost regarding operation and maintenance. It was decided to use the lifetime of the electrolysers as a guideline. Several sources were combined to decide the expected lifetime and corresponding scope of this thesis. Through the data analysis the following data regarding lifetime were found:

Source	Alkaline lifetime[years]	Source	PEM lifetime [years][14]
[64]	25	[64]	15
[73]	20	[88]	5*
[20]	15	[89]	20
		[73]	10-13
		[20]	12

Table 5 Lifetime of electrolysers

As the table shows estimating the lifetime is not completely straightforward because the different electrolyser technologies have different expected lifetimes, with different parts needing replacements. In many of these lifetime estimations they're including replacement of some essential equipment, for instance cell-stacks. The lifetime of cell-stacks in alkaline electrolysers varies from 8-12 years [73] [11], and for PEM it varies from 6.7 to 9 years [11] [72] [19]. As you've noticed the lifetime of cell-stacks don't necessarily add up to the lifetime of the entire electrolysis system. Which is to say that the cell-stack may mathematically need to be replaced for instance 1.6 times for alkaline and 1.8 times for PEM for a given period of time. The choice of lifetime can therefore inadvertently favor one of the technologies. In addition, there are many different lifetime estimates circulating with different assumptions as basis. This would be an argument for having different lifetimes for the two technologies. However, the replacement of cell-stacks is explicitly included in several of the offers for electrolysers. In addition, an economic comparison should be a comparison of the same length of time. All things considered a single, common lifetime was assumed in order to simplify the calculation process of this thesis.

With all this in mind the lifetime of 15 years seemed to be the best guesstimate for a joint lifetime of PEM and alkaline technology, and simultaneously is substantially less than the expected lifetime of storage- and other equipment. 15 years is within the estimated lifetimes of both technologies, though it is in the lower end of alkaline, and it should be sufficient with one cell-stack replacement for both technologies. Being in the low end reduces the value of alkaline output compared to PEM and is in that respect a conservative estimate. That will help ensure that the profitability of alkaline electrolysis isn't overvalued

[14] Some lifetimes were given in hours. These were converted to years by assuming electrolysis 80% of the year. The sources given in hours are marked with*. It is worth keeping in mind that these will probably be higher than what they are in years, as few electrolysers are on for ≥80% of the year.

and increase the reliability of the result. It is better to underestimate the profitability than overestimate it when it comes to a question of investment.

However, PEM and alkaline are worn down at different rates, and it is difficult to find specific information regarding the costs of replacing the different parts of each technology. Due to the PEM technology lifetime probably being stressed more than the alkaline (as 15 years is in the higher end of expected lifetime) it is not unlikely that the cost should be even more in favor of alkaline. But PEM has the advantage of more easily switching between production rates and turning on and off, but to what extent this affects the lifetime of it is not known.

3.2 The technical conditions at Fosen

This thesis' aim is to delve into the economic conditions for a hydrogen production at Fosen in order to perform a feasibility study. But to do that properly an overview of the technical conditions that can be expected is necessary. This will help evaluate the two different electrolysis technologies against each other as they have different characteristics and provide different limits for the calculation. Chapter 3.2.1 will investigate the probable production time through the year, and 3.2.2 will look into the number of restarts these conditions will entail for the electrolysers.

3.2.1 Production time through the year

Electrolysers have a rated power requirement at which hydrogen production at sufficient rate and purity is possible. It is therefore vital to see what fraction of the year Fosen Wind is capable of producing enough electricity to power the electrolysers.

Hydrogen need a high degree of purity to be commercially competitive, and modern electrolysers are capable of achieving that purity. Alkaline electrolysers for instance produce purity of >99.97%. However, this level of purity requires strict power conditions. The required purity can be achieved by keeping the electrolyser at constant and rated power [49] [52] [90]. Long periods of time with a production under the rated power requirement will be damaging to the production. Shutting down the electrolysers put a strain on the equipment and is damaging to the quality of the hydrogen. That means that not only the number of hours with adequate production is decisive, but also the number of non-production periods. This is due to the fact that production numbers alone don't paint the entire picture. For instance, a sufficient production in one continuous timespan of 7000 hours/year is highly preferable to a >7000 hour/year production broken up by several shut-downs every day. Therefore, a high production capacity combined with few timespans below required production capacity is ideal.

It was necessary to look into each of the six wind farms since they are geographically separated, and a hydrogen production would be located in one of them, or several separately. The total production at Fosen Wind is to that extent irrelevant for the conditions for hydrogen production.

The data set contains the production of each hour and was broken down into monthly production rates by using MATLAB, and the percentage of installed capacity were calculated. Each data point which has a percentage production beneath the required percentage production (of the installed capacity of that wind farm) was recorded. Bessakerfjellet broken into monthly percentage production in relation to installed capacity can be seen in Appendix C. When the table is expressed graphically it shows the varying production through the year(s).

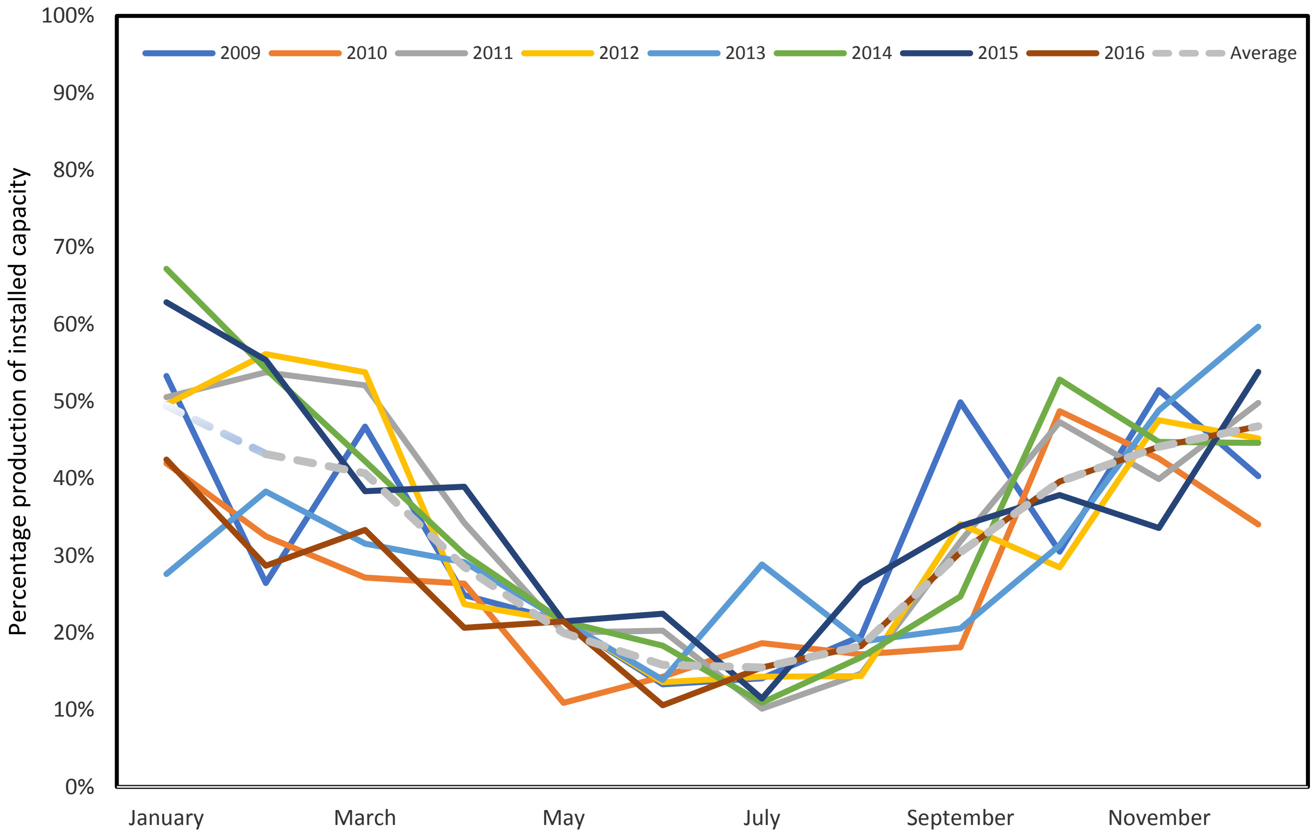

Figure 11 Monthly power production at Bessakerfjellet as a percentage installed capacity

Year	Percentage operation time at Bessakerfjellet
2009	32.7%
2010	27.7%
2011	35.4%
2012	33.5%
2013	30.8%
2014	35.7%
2015	36.4%
2016	29.3%

Table 6 Percentage operation time at Bessakerfjellet year by year

The graph shows that for a single month (January) the power production can vary by as much as 39.6 percent points (2013 and 2014). This illustrates the fluctuating nature of wind, and the challenges of estimating long-term power production rates. However, in the summer months, when the production is at its lowest, the variance is also very low. The lowest value recorded is from July 2011 when production was at a monthly average of 10.1 percent of installed capacity. Despite this being the lowest average production it yields an average production of 9.45MW the smallest wind farm (Hitra 2) enough to power several electrolysers.

In total Bessakerfjellet have an average hourly percentage production of power of 32.71% of installed capacity. Over the period 2009-2016 the monthly average production varied from 27.7% of installed production (2010) to 36.4% of installed production (2015)[15] (see Table 6). If these limits of production is assumed to give an idea of the maximum and minimum production at Fosen Table 7 shows that Fosen will probably produce at a higher percentage level than the data from Bessakerfjellet suggests.

	Installed effect [MW]	Pre-construction estimated production [GWh]	Estimated percentage operation time	Minimum percentage operation time according to the data from Bessakerfjellet	Maximum percentage operation time according to the data from Bessakerfjellet
Storheia	288	1000	39.64 %	27.7%	36.4%
Geitfjellet	180.6	548	34.64 %	27.7%	36.4%
Harbaksfjellet	136	443	37.18 %	27.7%	36.4%
Hitra 2	93.6	290	35.37 %	27.7%	36.4%
Kvenndalsfjellet	113.4	405	40.77 %	27.7%	36.4%
Roan	255.6	900	40.20 %	27.7%	36.4%

Table 7 Overview of the wind farms at Fosen

Table 7 shows that Bessakerfjellet has a significantly smaller average production as a percentage of the installed effect as what is expected at Fosen. This increases the likelihood that this calculation will not exceed the boundaries of profitability and will to that extent decrease the likelihood of overestimating the production capacity.

The production as a percentage of installed capacity can be expressed graphically to show how multiple electrolysers put a strain on the plant's ability to provide sufficient amounts of power. There are two sizes of *alkaline* electrolysers that are the basis for this thesis; 2.3MW and 6.8MW. The X-axis in Figure 12Figure 12 Percentage of time of adequate represents the number of 2.3MW electrolysers that are installed. Three 2.3MW electrolysers will roughly equal one 6.8MW electrolyser. On those grounds there were no need to complicate the calculation further. Every third unit on the x-axis equals one 6.8 MW electrolyser. This graph is calculated by assuming that when a percentage production at Bessakerfjellet was beneath the percentage production needed at the corresponding wind farm the production stops.

[15] See Appendix C

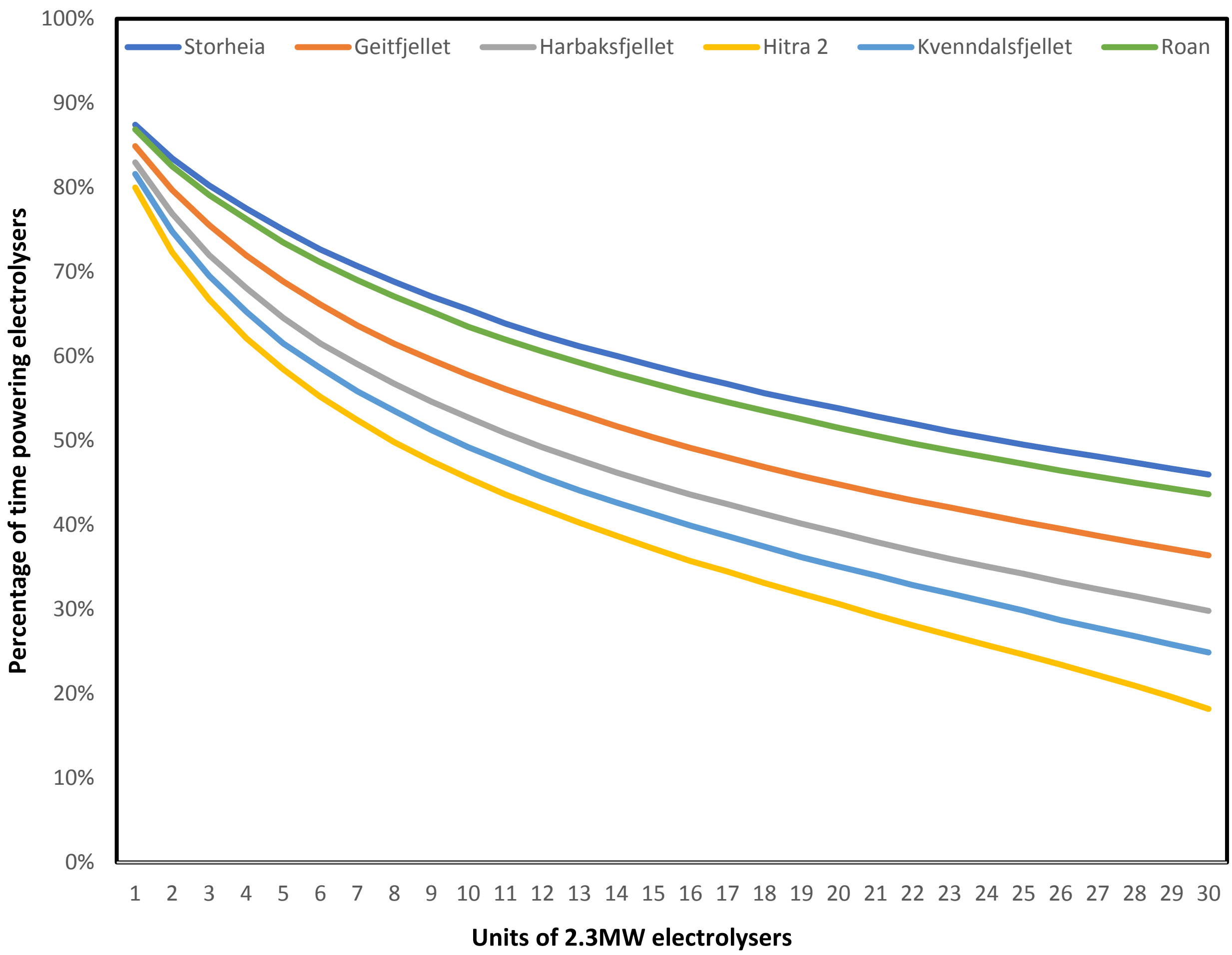

Figure 12 Percentage of time of adequate power production for alkaline electrolysers

For PEM electrolysers the 2.02 MW electrolyser make up basis (see Figure 13). The difference to the alkaline electrolysers is barely visible, but the wind parks' ability to power the electrolyser will of course be marginally better as the rated power is lower.

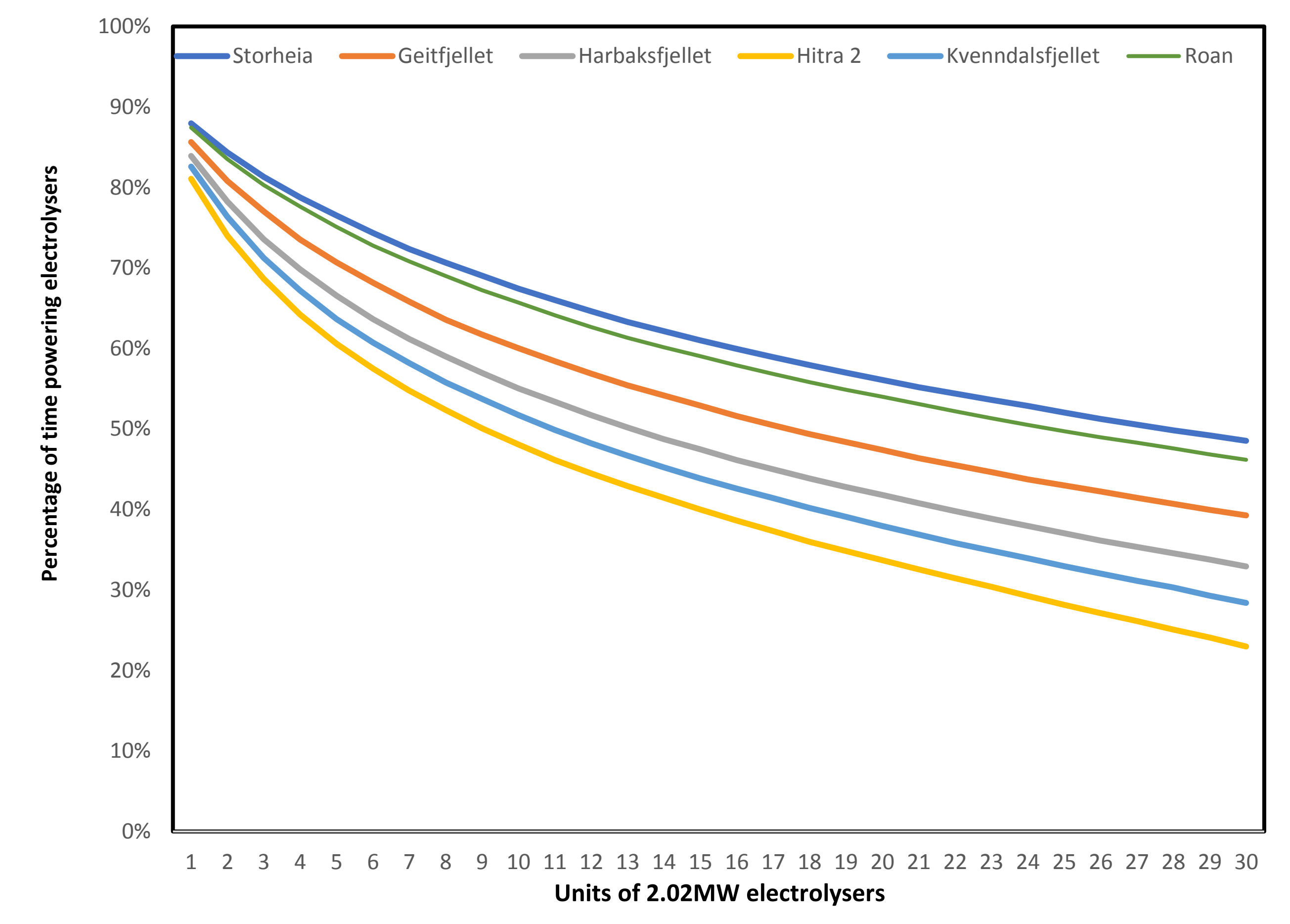

Figure 13 Percentage of time of adequate power production for PEM electrolysers

On the basis of Figure 12 and Figure 13 it is assumed that one unit will be able to produce hydrogen 80 % of the year, or around 7000 hours per year. This is a conservative estimate as all the wind farms are above 80 percent for one electrolyser. Later, when the production capacity of a range of electrolysers is calculated this operation time is adjusted according to the results shown in the previous graphs.

Furthermore, the calculation of the number of forced restarts skews the impression somewhat. This is due to the MATLAB code finding all time samples with a percentage production below the percentage required to produce enough power for the electrolysers. This means that larger installments, of several electrolysers, will be "punished" more than the smaller ones. Because eight electrolysers of 2 MW needing 16 MW will all be turned off at a production of 15 MW. In addition, Bessakerfjellet has an average percentage production below that expected at all of the wind farms at Fosen as mentioned earlier.

3.2.2 Number of forced restarts

The number of restarts of the electrolysers is important in order to evaluate the PEM electrolyser versus the alkaline electrolyser. Before every restart the alkaline plant needs to be cleansed with nitrogen to avoid detrimental effects to the machinery and the quality of the hydrogen [91]. However, the number of restarts is not the same as the number of moments in time power production was below required input power to the electrolysers. Seven moments (hours in the dataset from Bessakerfjellet) in a row below required power input only requires one restart. By using MATLAB, a program worked its way through the data set and store the number of sequences below required power input.

The number of restarts were found for several electrolyser configurations in the period 01.01.2009 to 23.06.2016. Keep in mind that the data yields information on an hourly basis, so it is assumed that the data spanning each hour are pretty constant or average moment pictures of the production. The number of restarts is therefore subject to some insecurity.

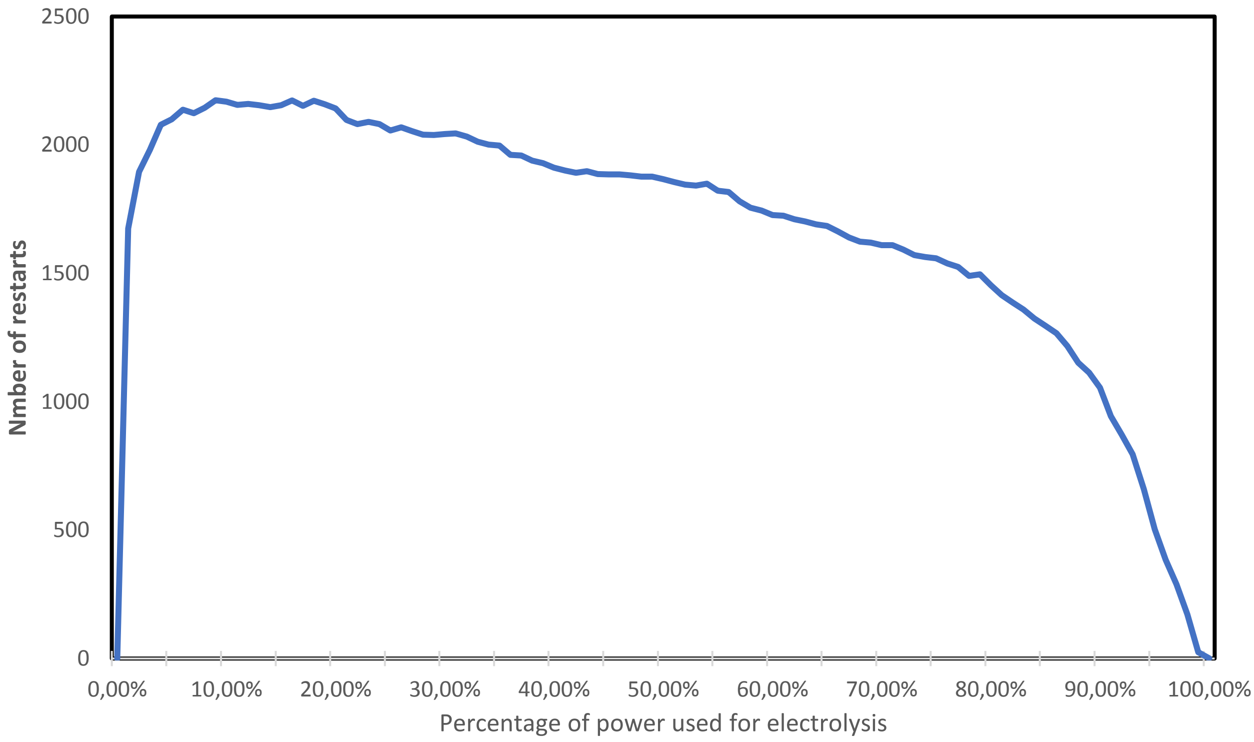

Figure 14 Number of forced restarts due to insufficient power production as a function of a increasing percentage of power used to operate electrolysers

The graph shows the number of necessary restarts at each production rate as a percentage of the installed capacity. However, also in these calculations the production ceases as soon as the wind production is below the rated requirement.

It is difficult to say something specific about the detrimental effects or costs of being forced to shut down electrolysers as markets actors weren't willing to share that information. But these graphs show that there are at least relatively small differences in the number of needed shutdowns up towards 80% operation time.

3.3 Production

This section will investigate the CAPEX and OPEX of an electrolyser production unit with an assumed lifetime of 15 years.

3.3.1 CAPEX and OPEX

By conducting the calculation described in chapter 2.3.2 the resulting CAPEX for the electrolysers are as in Table *8*:

	Cost [MNOK]	Foundation and building [MNOK]	Installation of equipment [MNOK]	Building plot [MNOK]	Battery back-up [MNOK]	Compressor [MNOK]	Buffer tank [MNOK]
Electrolyser A	19.00	4.00	2.50	0.30	4.00	4.00	0.11
Electrolyser B	48.00	10.00	6.25	0.75	4.00	12.00	0.32
Electrolyser C	19.36	3.22	0.69	0.30	-	3.22	0.09

Table 8 Overview of CAPEX for electrolysers

The most obvious point of discussion is the CAPEX for battery back-up which are the same for electrolyser A and B. There was no information available to determine how large the batteries for each alkaline electrolyser option needed to be. Several market actors were contacted, but this did not result in the required information. With that in mind it was decided to use the same cost for each option because the characteristics of the supplied battery example is 550 kWh and 500 kW. Remember that the battery is meant to allow the electrolysers to be turned off safely when the power production is too low, not to keep them in operation. To that end it seems reasonable to assume that the mentioned battery is more than sufficient. Furthermore, because it was difficult to find information regarding the development of cost due to smaller sizes it was safer for electrolyser A to assume the larger cost option and avoid calculating a too low CAPEX. However, it would be beneficial to use exact information about the required size of the battery and for several sizes.

Furthermore, the cost for installation of equipment for the PEM electrolyser is a source of doubt. It reportedly contained more expenses than the corresponding category for the alkaline electrolysers and despite of that it is much cheaper. However, the cost data is directly from supplier and must therefore assumed to be correct.

Another point of discussion is the buffer tank. The buffer tank was included in the data for electrolyser C. The storage capacity was however so small (2 m^3) compared to the production that it was obviously not meant as a lasting storage option. Rather it seems it will serve as a back-up in case of unsuspected production fluxes or something of that sort. It was therefore adjusted linearly with the production rate of each electrolyser. In addition, it is a close to negligible cost and will not significantly affect the final cost of the unit. This could of course argument for removing that expense but if it truly does represent a buffer in its more literal sense it is wise to be aware of the need. On those grounds it was included in the CAPEX overview.

If Table 8 is expressed in sector diagrams it shows that the expenses for the alkaline electrolysers are very similar (see Figure 15). Which is to be expected as any information regarding one but not the other, was linearly calculated for the other one. The graph for electrolyser C on the other hand show that the cost for buying the equipment is more dominating than for the alkaline electrolysers. This is due to the battery expense not being necessary.

The graphs are so similar because as mentioned any difference in what expenses was included in the information was assumed to be linearly dependent upon production rate. This is of course not correct because it would entail that the two technologies have the exact same features and characteristics. But there was no available information about how to address those specific costs differently for the different technologies. An assumed linear relation will hopefully even out to some extent across the total expenses. If it is assumed too big for one technology in one expense it will be too small in the next. This is a hopeful simplification as some expenses were much larger than other ones, for instance batteries compared to building plot. But in lack of more precise information it will anyhow provide a prudent basis for further calculation.

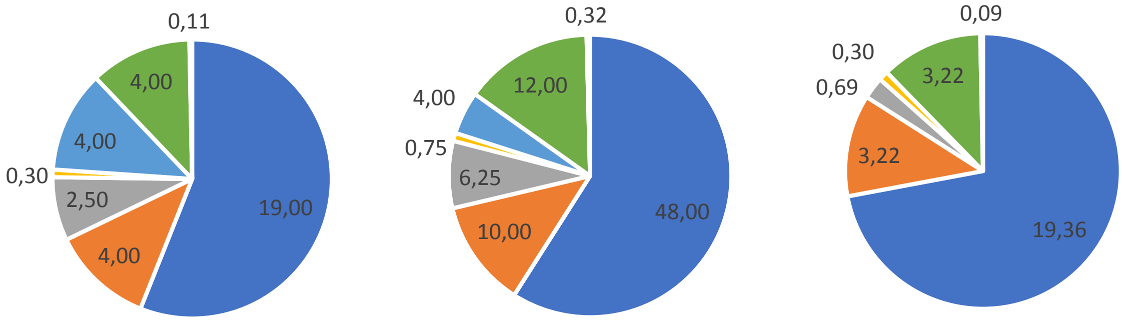

Figure 15 CAPEX distribution for the electrolyser options, A, B and C respectively

When Table *8* is summed it yields the following table over total CAPEX for the three electrolyser options:

	Sum [MNOK]
Electrolyser A	33.91
Electrolyser B	81.32
Electrolyser C	26.86

Table 9 Summed CAPEX for electrolysers

The OPEX assumptions and calculations resulted in the following table for the first year:

	Maintenance, incl. replacing cell stack [MNOK]	Average annual cost of water [MNOK]	Cost of standby electricity [MNOK]	Cost of electrictity [MNOK]
Electrolyser A	0.38	0.016	0.05	6.32
Electrolyser B	0.96	0.024	0.16	18.62
Electrolyser C	0.76	0.015	0.00	5.68

Table 10 Overview of OPEX for electrolysers

OPEX is of course an annual expense so future expenses are discounted by a discounting factor r in accordance with equations (2) and (3). Table 10 list the first year to give insight into the distribution of cost at which categories of expenses that are involved. However, the complete picture of OPEX is only painted through showing the cost over the entire lifetime of 15 years (see chapter 3.6).

Water cost has some one-time expenses, like a water gauge and a fixed price for connecting to the water grid. These are included in the total OPEX cost for the entire 15-year lifetime, but not included in the discounted cost (see appendix D for complete calculation). These expenses were not moved to CAPEX in order to avoid confusion, and those expenses are negligible when compared to the total cost. As this table show this cost is negligible. There are quite large differences in water cost from municipality to municipality but not large enough to make them significant for the total OPEX.

In accordance with the number of hours Fosen are capable of powering one electrolyser the operation time was set to 80 percent of the year (see chapter 3.2.1). This allowed for calculation of the electricity value by using the calculated electricity price of 0.32 NOK/kWh. The stand-by mode is the remaining 20 percent of the year.

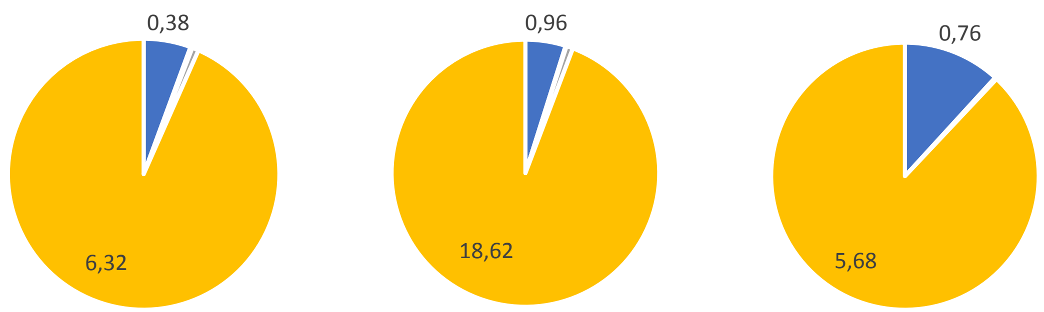

Figure 16 OPEX distribution for the electrolyser options, A, B and C respectively

This gives the following summed table over a 15-year lifetime with using equation (3) with a discounting factor of r =0.08:

	Total OPEX
Electrolyser A	64.74
Electrolyser B	188.93
Electrolyser C	68.29

Table 11 Total OPEX for one unit of electrolysers

3.3.2 Total cost:

The total levelized cost is calculated by equation (3) (TLC). Several industrial sources state that OPEX constitutes 75% of the total cost, and several scientific articles state an OPEX around 70-75% [7] [92]. The fraction of the total cost the OPEX constitutes is therefore included in the total cost table. If the fraction is of the same order of magnitude it gives credence to the calculations and increases the reliability of the sources. By summing CAPEX and OPEX we get the following table of total costs

	TLC	OPEX fraction[16]
Electrolyser A	98.65	66%
Electrolyser B	270.25	70%
Electrolyser C	95.55	71%

Table 12 Sum of CAPEX and OPEX costs for alkaline electrolysers

Table 12 shows that OPEX constitute a very reasonable fraction of the total cost according to industrial and scientific articles. This is an indication that the previous calculations stem from reliable sources, and that the assumptions used to calculate them are reasonable.

16

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

Equation (2) for Levelized cost of Hydrogen can then be used to find the cost on a per kg basis.

	LCOH [NOK/kg]
Electrolyser A	28.22
Electrolyser B	25.77
Electrolyser C	31.51

Table 13 Total cost per kg produced hydrogen

The electrolyser manufacturer NEL has stated a target of 25 NOK/kg for the electrolysis at an 8 tons per day level [93]. However, that is at an electricity price of 0.40 NOK/kWh. The projected price for this thesis was 0.32 NOK/kWh. The fact that this calculation was for a smaller daily production, but with a lower electricity price leads to believe that the calculation at least is of the correct order of magnitude, but maybe a bit too low. However, the costs are within the calculations of DNV GL's report for the Ministry of Climate and Environment and the Ministry of Petroleum and Energy which states costs of 22-44NOK/kg for alkaline and 31-51 NOK/kg for PEM [20]. This points to the cost being in the low range, but within reasonable values. This further increases the reliability of the data and information used for these calculations.

3.4 Storage

3.4.1 Compressed hydrogen

By investigating the product lists of tank producers Hexagon and Mahytec and by using equations (5) and (6) a list of pressure tank options was created expressing the weight and volume percentage (see Table 14 and Appendix E) [94] [95]. But in order to show the difference pressure makes "high pressure tanks" was defined as tanks with a pressure of >500, and "low pressure tanks" as all options below that pressure. This yield the following table of average values:

	wt%	v%
High pressure	4.7	3.8
Low pressure	5.6	1.8

Table 14 Average weight- and volume percentage

Despite scientific articles like Sdanghi et al. (2019) reporting that modern storage vessels achieve an average weight percentage of 3-4 wt%, it would seem that according to the manufacturers the actual number is closer to 4,5-6 wt% [96]. The span is due to differences according to which pressure that is used.

Trucks transporting compressed hydrogen will most likely use low- to medium pressure storage tanks, and with a wt% of 5.6 each 10-ton truck will have a cargo of 560 kg of hydrogen [16]. This fits nicely with the data gathered from the suppliers and the US Department of Transportation certification for composite tube trailers to carry 560 kg onboard, and it complies with the targets of the US Department of Energy for *Light-Duty Vehicles* for 2020 and 2025, 4.5 wt% and 5.5 wt% respectively [97] [98].

Assuming that the hydrogen production will be closely coupled with the demand and daily production, there is no need for large storage capacities on-site. That means that the size of the storage facility increases with the electrolyser and accompanying production rate. However, it would be wise to have some buffer storage in case of accidents delaying a transport truck for instance so a storage buffer capacity of 15% is included. It is assumed that it is desirable to have a consistent scheduled transport each day. Which is to say that trucks will arrive and leave at approximately the same times each day. As the trucks' potential cargo doesn't add up to the total production per day, there will be some unutilized cargo in each truck (production per day[kg]/cargo[kg] ≠ integers).

This strategy means that larger production rates don't affect the storage size, but the transport frequency requirement. That gives the following table:

	Type	Production [kg per day][17]	Number of truck routes per day	Production time between truck arrival [day]	Required storage capacity [kg][18]	Storage tank size [m^3] [19]
Electrolyser A	Alkaline	1000	~2	0.5	~575	~82.4
Electrolyser B	Alkaline	3000	~6	0.167	~575	~82.4
Electrolyser C	PEM	804	~2	0.5	~462	~66.2

Table 15 Storage requirements for compressed hydrogen

CAPEX:

A typical 500 kg tank at 400 bar in a 20 ft ISO container (Intermodal container [99]), will come at a cost of around 2.6 MNOK. A 1200 kg tank will require a 45 ft ICO container at a cost of around 6.2 MNOK. While a 4800 kg tank will be stored in four ISO containers at a cost of around 24.7 MNOK. These storage tanks are at a pressure quite a bit above the pressures needed for storage at such a production site. Gruger et al. (2018) operates with tanks a 1000 bar with a cost of 11 143 NOK/kg (around 6.4 MNOK for 575 kg), and one of 50 bar with a cost of 6156 NOK/kg (around 3.5 MNOK for 575 kg) [100]. Hence, despite high pressure storage tanks needing less material due to smaller surface are it is much more expensive to store at higher pressure, due to more expensive materials. It is hence likely that the cost of stationary storage at lower pressure will be less expensive than the tank examples listed previously. Storage tanks are also delivered in several sizes and it is possible that ordering specific sizes can yield higher costs as they are not standardized. However, if plotted into a graph the storage tank examples prove to have an almost perfectly linear cost development (See Appendix F). In addition, it is uncertain just how much less expensive say a 100-bar tank would be. It is hence assumed that the costs are close to linear with the examples to avoid calculating too low expenses. The cost of the storage tanks corresponding to the production sizes is as follows:

[17] Number of truck routes = Daily production/cargo size and round up to closest integer

[18] Required storage capacity = Production per day/number of trips per day + 15% capacity

[19] Storage tank size = Required storage capacity/number of kg per m3 (=6.98kg/m^3)

	Production [kg per day]	Storage tank size [m^3]	CAPEX[20] [MNOK]
Electrolyser A	1000	~82.4	2.96
Electrolyser B	3000	~82.4	2.96
Electrolyser C	804	~66.2	2.39

Table 16 CAPEX of compressed storage

This is calculated using the per kg price used in the examples of 500kg, 1200 kg and 4800 kg. If the numbers from Gruger et al. (2018) is used instead and assumed a linear relationship the cost at a 100 bar will be 6148.5 NOK/kg. That yields a cost for the electrolyser options of 3.54 MNOK, 3.54 MNOK and 2.84 MNOK respectively. However, Gruger's calculations are based on sources from 2013 and 2014. The examples given previously are from May 2019. It is likely that storage cost has been decreased due to development in a growing industry the last 5 years. Hence, the cost originating from the examples introduced earlier will be used in this thesis.

A compressor is necessary to reach the desired pressure. The compressor is assumed to constitute almost all utilities needed to operate (2) the compressed storage ((2) from chapter 2.4.2.1). There is of course some other equipment (pipes etc.), but that is assumed to be negligible. The CAPEX for compressors is included in the CAPEX cost for production however (see chapter 3.3.1) and will hence not be expressed here.

OPEX:

The scope of this thesis is 15 years. Greiner et al. (2006) operate with 30 years for storage tanks for hydrogen [71]. This indicates that the lifetime of the storage equipment exceeds the scope of thesis and a replacement would not be necessary within that scope. That means that costs will on a per kg basis be artificially high as the CAPEX can be distributed over a larger production cycle. However, this also decrease the possibility of an investment decision taken on the basis of too low costs, which is a positive effect.

The operational costs (2) ((2) from chapter 2.4.2.1) are mainly the energy used for compression, which requires 9-12% of the final energy content in the hydrogen [34]. However, he production cost is also expected to improve further in the near future [42]. Greiner & Korpås (2006) set yearly maintenance and operation of the compressor to 4 percent of the CAPEX, which equals roughly 150 000 NOK. Gruger et al. (2018) set the same expenditure to 192 000 NOK [100]. The average annual cost for operating the compressor is 360 000 NOK when using the percentage estimation mentioned above. That means that it is in the higher range according to available scientific sources. Which once again decreases the chance of the results being too low, and thereby increasing the risk of anticipating an unreasonable investment.

Hydrogen has an energy density in the range of 120 to 142 MJ/kg [101]. The assumed energy density for this calculation is the average of 131 MJ/kg and the assumed energy consumption for compression is 10.5% of the final energy content in the hydrogen produced. This leads to the following table:

[20] Using formula y=0.0051x + 0.0315 as extrapolated from storage tank examples

	Size [kg H_2/day]	Production in one year [kg]	Energy content in hydrogen [GJ]	Energy used for compression [kWh]	Value of energy consumed in the first year [MNOK]
Electrolyser A	1000	365,250	43,830	12,175,097	3.90
Electrolyser B	3000	1,095,750	131,490	36,525,292	11.71
Electrolyser C	804	293,661	35,239	9,788,778	3.14

Table 17 Overview of OPEX for compressed storage

Table 17 gives an overview of the OPEX, however, when the calculation stems from a percentage of energy in final product there is nothing to be gained from increasing the production rate, the OPEX will constitute the same share of the total cost. That is somewhat unreasonable as it is likely that larger production rates reduce the energy required to store a kg of hydrogen. Large-scale is as a rule of thumb less expensive than small scale. However, this percentage rule of thumb for the OPEX was the only sufficient information that was found during research and is therefore used.

Maintenance costs (3) ((3) from chapter 2.4.2.1) for storage are assumed to be of smaller magnitude than electrolysers, as they entail more complex operations. Maintenance costs of electrolysers were assumed to be 1.5-2 percent of CAPEX per year over the lifetime of the 15-year scope. The maintenance cost of the storage tank is hence assumed to be 1 percent of CAPEX for the scope of this thesis of 15 years. Which yields an operation and maintenance cost of:

	Maintenance cost [MNOK]
Electrolyser A	0.45
Electrolyser B	0.45
Electrolyser C	0.3

Table 18 Maintenance cost for compressed storage

Total cost:
By using equations (2) and (3) the Levelized Cost of Hydrogen Storage (LCOHS) by compression can be found, and that is expressed in *Table 19*.

	LCOHS for compression [NOK/kg]
Electrolyser A	11.92
Electrolyser B	11.10
Electrolyser C	11.71

Table 19 Levelized Cost of Hydrogen Storage (LCOHS)

3.4.2 Liquefaction

Liquefaction is considered to be profitable for higher demands (>500 kg/day) and mid-range distances according to Moradi et al. 2019 [35], but market actors have stated that such facilities should be in the 15 tpd (tons per day) range to be profitable. In 2011

California Air Resource Board expected hydrogen fuel to be liquefied by 2020-2025 due to its higher storage capacity [102]. Electricity consumption in most modern facilities is around 10 kWh/kg, but it is thought that 6 kWh/kg H_2 is achievable. Capital investment constitute around 40-50% of the specific liquefaction cost for newly constructed liquefaction plants [83].

Market actors has disclosed that a LH2 production of 30 tpd will yield a liquefaction cost of around 1 €/kg LH2 (9.73 NOK/kg), while a 1.5 tpd plant will yield a cost of around 4 €/kg LH2 (38.93 NOK/kg).

In a report from 2003 a graph over Capital Costs per unit, for small to medium units, is presented [103]. 400 Mscf (million standard cubic feet) per year is around 944 tons per year, which yields 2.6 tons per day. This give a cost of 0.27 $/100scf which equals 2.34 NOK/0.236 kg which yields a cost of 10 NOK/kg.

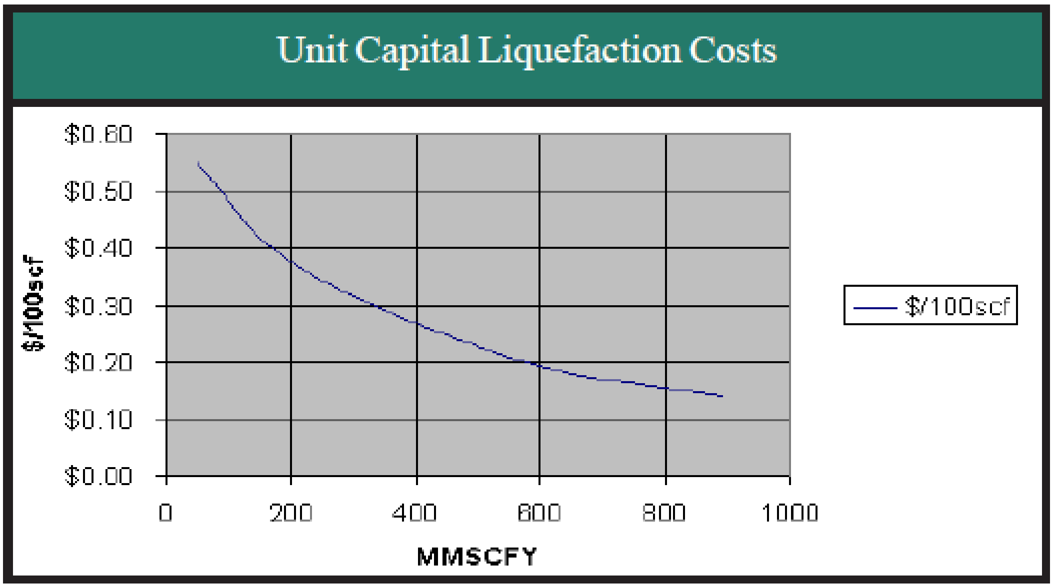

Figure 17 Capital Liquefaction Costs according to West (2003) *[103]*

According to the graph this will be about halved if the production is doubled. Which means that liquefaction of 5 tpd will yield a CAPEX of around 5 NOK per kg. Assuming that CAPEX of liquefaction constitutes about half of the total cost (see Figure 18 below and the information from [83] mentioned earlier) that yields a total cost of 10 NOK/kg at a production rate of 5 tpd. Several values could be extrapolated from that graph, but since the source is quite old it was decided to only include one value from that graph to avoid it skewing the results in case of significant change since 2003.

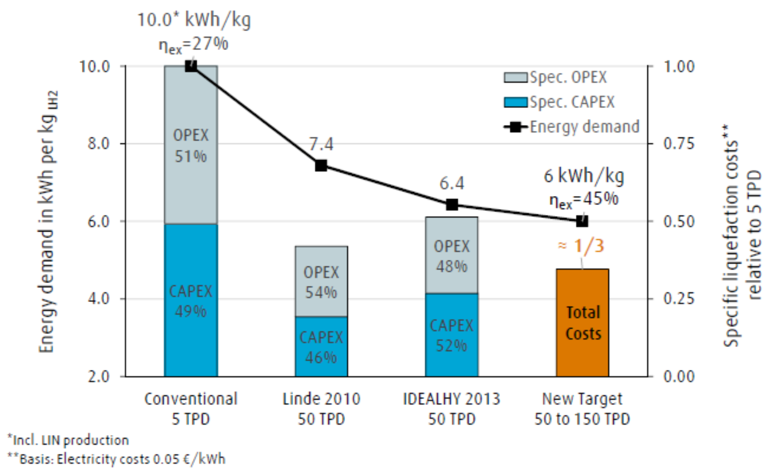

Figure 18 Cost distribution of different liquefaction technologies *[104]*

According to Cardella et al. (2017) there are substantial large-scale benefits when liquefying [104]. But increasing the production rate from 5 to 50 tpd the energy consumption is reduced from 10 to 6.4 kWh/kg (see IDEALHY 2013 in Figure 18).6.4 kWh/kg will reduce the energy used for cooling from 25-35% to 19.2%. However, this constitutes an economic tradeoff as an energy consumption of 7.4 kWh/kg allows for a relative reduction of OPEX and CAPEX of around 20% (see Linde 2010 in Figure 18). The graph allows for calculation of CAPEX and OPEX cost by assuming the share of OPEX electricity consumption constitute. By assuming that electricity constitutes around 50% (in alignment with [83]) of the total OPEX and the electricity cost of 0.05 €/kWh used by Cardella et al. (2017) as in Figure 18 it will give the following total cost:

Type of technology	Cost calculated using the electricity consumption and assuming the share of electricity [NOK]	Cost calculated through the percentage relative reduction seen in the y-axis (see Figure 18) [NOK]
Conventional (5 tpd)	19.22	19.22
Linde 2010 (50 tpd)	13.43	7.69
IDEALHY 2013 (50 tpd)	13.07	9.61
New target (50-150 tpd)	7.68	6.34

Table 20 Data for liquefaction cost

These calculations fit nicely with numbers yielded to me by market actors, which said that a typical increase in the total cost is 10 to 20 NOK/kg for medium facilities. I was also told that and a production increase from 5 to 20 tpd will roughly halve the cost.

The entire data set is presented in Appendix G. This data yields the following function

$$y = -4.619\ln(x) + 29.079 \quad (7)$$

This function is expressed in Figure 19 together with the data points.

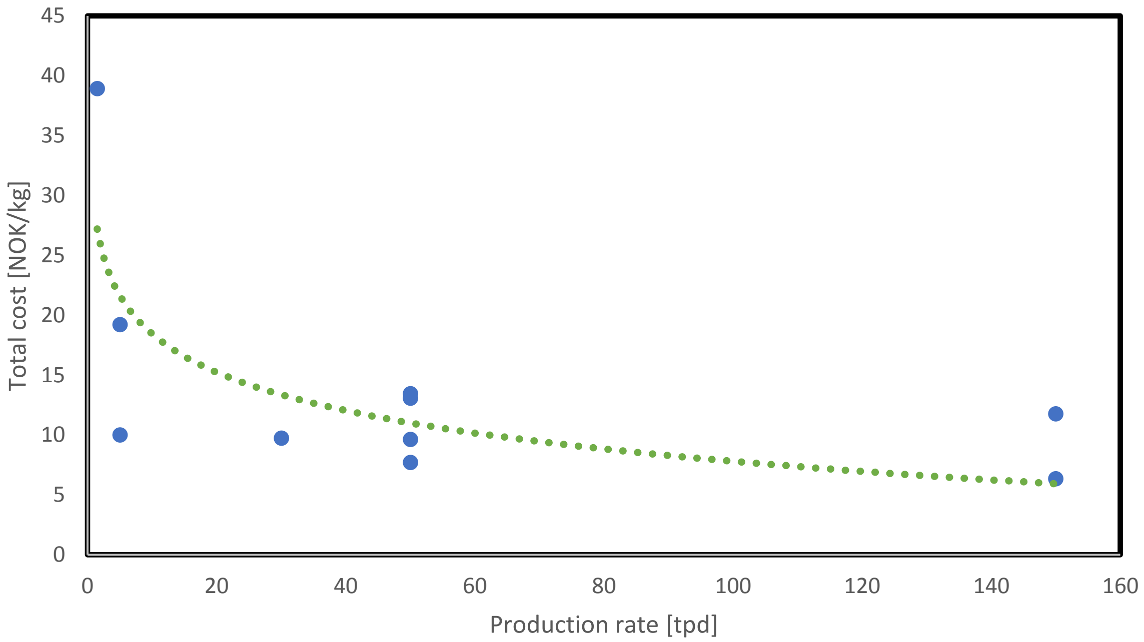

Figure 19 The graph for total cost of liquefying hydrogen

The graph fits nicely with information disclosed to me that liquefaction will lead to extra costs of 10 to 20 NOK/kg for medium liquefaction quantities. However, information also said that as liquefaction increase from 5 tpd to 20 tpd would roughly halve costs. This points to the possibility of smaller production sizes not being as expensive as the green line indicates.

It doesn't necessarily need to be either only liquefaction or only compression. The profitability of a sufficiently large facility needs to be weighed against the demand. This thesis does not aim at analyzing the potential demand for liquefied hydrogen. However, it is worth mentioning that the world's first hydrogen ferry is being built by Norled in Norway and will be in operation from 2021 [105]. Due to lack of liquefied hydrogen production in Norway it is forced to import the hydrogen from either France or Germany [106]. So, the customer base for liquefied hydrogen is growing. The project aims at using liquid hydrogen and would require several hundred kg per day. If this actually ends up using liquefied hydrogen, there are reasons to expect an increasing demand of liquefaction the next decade.

The cost related to liquefaction is calculated as the cost of building a facility capable of liquefying the entire hydrogen production in order to give a basis for comparison with compression. The specific cost is determined by using the function extrapolated from the data.

	Size [kg H_2/day]	Total cost [MNOK]	Cost per kg [NOK/kg H_2]
Electrolyser A	1000	127.98	29.1
Electrolyser B	3000	316.89	24.0
Electrolyser C	804	106.42	30.1

Table 21 The total cost of liquefied storage

These results also fit nicely with DNV GLs report saying that a 1000 km transport and delivery liquefied hydrogen will increase cost by 25 NOK/kg H2 compared to gaseous hydrogen [20]. These costs will increase cost relative to compressed by around 15-20 NOK, and that is for a much shorter distance than 1000 km.

3.5 Transport

3.5.1 Cost of transport

The cost of transport is a function of transport distance, and thereby number of trips per day. By using cost data for five different routes ending at Brattøra and finding the distance and the average cost per container per km can be calculated (see Appendix H). This is necessary in order to avoid calculating all the different route options as the location of the production unit hasn't been decided. This statistic reportedly includes all necessary cost; salary, equipment, trucks etc.

From	To	Distance [Km]	Time [min][21]
Roan	Brattøra	129	157
Harbaksfjellet	Brattøra	117	151
Geitfjellet	Brattøra	74.3	68
Storheia	Brattøra	75.6	105
Hitra 2	Brattøra	155	140
Kvenndalsfjellet	Brattøra	99.4	130
Average		**108.4**	**125.2**

Table 22 Route information

The distance is found using google maps' built-in distance estimation. This allows for a calculation of average cost per km.

[21] Assumed average velocity of 80 km/h

Route	Prices per km [NOK/km]		Prices per km per container [NOK/km*#container]	
Wind farm location	One container	Two containers	One container	Two containers
Roan	58.1	73.2	58.1	36.6
Harbaksfjellet	64.1	76.2	64.1	38.1
Geitfjellet	69.3	109.9	69.3	54.9
Storheia	68.1	71.2	68.1	35.6
Hitra 2	48.4	82.1	48.4	41.1
Kvenndalsfjellet	63.6	73.0	63.6	36.5
Average	**61.9**	**80.9**	**61.9**	**40.5**

Table 23 Cost of transporting containers

The table show that as one would expect it is profitable to increase the transport size.

Compressed hydrogen:

With a wt% of 5.6 each container will transport 560 kg of hydrogen. The average distance is 108.4 km. At an average cost of 51.2 NOK/km*container this yields a cost per trip of 5550 NOK. That leaves a cost of 9.91 NOK/kg H_2 transported.

However, be mindful of the fact that larger quantities will reduce cost. Transportation from Electrolyser B for instance requires thrice the number of truck routes. It is hence reasonable to assume that the unit cost will be reduced, the price per km per container being 65 % of the price per two containers. At a single electrolyser the difference is this big, but as soon as larger quantities are produced there will be transportation of two containers per trip. The constant use of the average value will sometimes be too high, and sometimes be too low, hopefully this will cancel each other out to some extent. In chapter 3.8, where calculations for systems consisting of several electrolysers are presented the cost of the lowest number of electrolysers will be the highest, and then decrease with increasing numbers of electrolyser to a stabilizing point.

A transport container with a pressure of 350 bar has a hydrogen cargo of 353 kg hydrogen and cost 1.6 MNOK. That gives a per kg cost per container of 4600 NOK. This container has a lower cargo capacity than what scientific literature says is a reasonable weight, but it will constitute the basis for these calculations. Furthermore, it is assumed that the electrolyser options will require the same number of containers as the number of truck routes per day. This is not necessary for the smaller production units, as two trips a day can be covered with a single electrolyser. But as the cost is small over the 15-year lifetime it is been decided to rather have a more than sufficient capacity. The electrolyser options is estimated to require the following number of containers:

	Number of truck routes per day	Containers needed for compressed H_2	Cost [MNOK]	Cost per kg H_2 [NOK/kg]
Electrolyser A	2	2	3.2	0.73
Electrolyser B	6	6	9.6	0.73
Electrolyser C	2	2	3.2	0.91

Table 24 Storage information

Liquefied hydrogen:

The average cargo weight when transporting liquefied hydrogen is 4000 kg [16]. This is transportation of another medium, with other characteristics. But it is assumed that the difference in cargo will have a negligible effect on the cost per trip. That means that the average cost per trip is around 5550 NOK. That leaves a cost of 1.39 NOK/kg.

Liquefied hydrogen will for larger scale need around 1/7 of the containers that compressed needs. However, for small scale the cost will be similar as you can't purchase 14.3% of a container. Containers for liquefied hydrogen will possibly also be of another price range. Unfortunately, the search for information about that cost difference was not successful. With that in mind it was decided to not include the costs for containers to not skew the results in favor of liquefied hydrogen. In addition, the container cost calculated previously is low and almost negligible, and won't significantly affect the investment basis. But for a more detailed analysis the cost of the necessary storage device on the trucks themselves should be included.

3.5.2 Comparison of transport solutions

The cost calculated above is based upon average cost in order to find a representative cost for a variety of production sizes. This means that production rates which requires two containers will have lower transport cost than those calculated, and the lowest production rates would actually have higher costs. With that being said this is the cost for the two transportation options:

	Cost [NOK/kg]
Compressed	9.91
Liquefied	1.39

Table 25 Comparison of cost per kg for transport of compression and liquefaction

3.6 The total cost

Summing up the production stage, storage and transportation over the 15-year scope you get a total cost which yields the following cost per kg hydrogen produced. This table and Figure 20 show the break-even price for the hydrogen fuel. The break-even price is the price at which an asset must be sold to recover the costs of producing and owning it [107].

Stage	Alkaline				PEM	
	Electrolyser A [NOK/kg]		Electrolyser B [NOK/kg]		Electrolyser C [NOK/kg]	
Production	28.22		25.77		31.51	
Storage	Compressed	Liquefied	Compressed	Liquefied	Compressed	Liquefied
	11.92	29.10	11.10	24.00	11.71	30.10
Transport	9.91	1.39	9.91	1.39	9.91	1.39
Total	**50.05**	**58.71**	**46.78**	**51.26**	**53.13**	**63.00**

Table 26 Total cost

Table 26 shows that liquefied hydrogen is not much more expensive than compressed hydrogen. The obvious culprit is transport cost of liquefied. As the cost related to transporting the hydrogen from the original tank to the trucks is assumed included in the storage cost or negligible it is possible that some significant costs are missing. However, the research for a detailed cost overview of the trucks themselves it wasn't possible to address that cost. It is presumed that it is better to not speculate on this cost and rather present the cost as it is, and then open up for further examination of the transport cost of liquefaction.

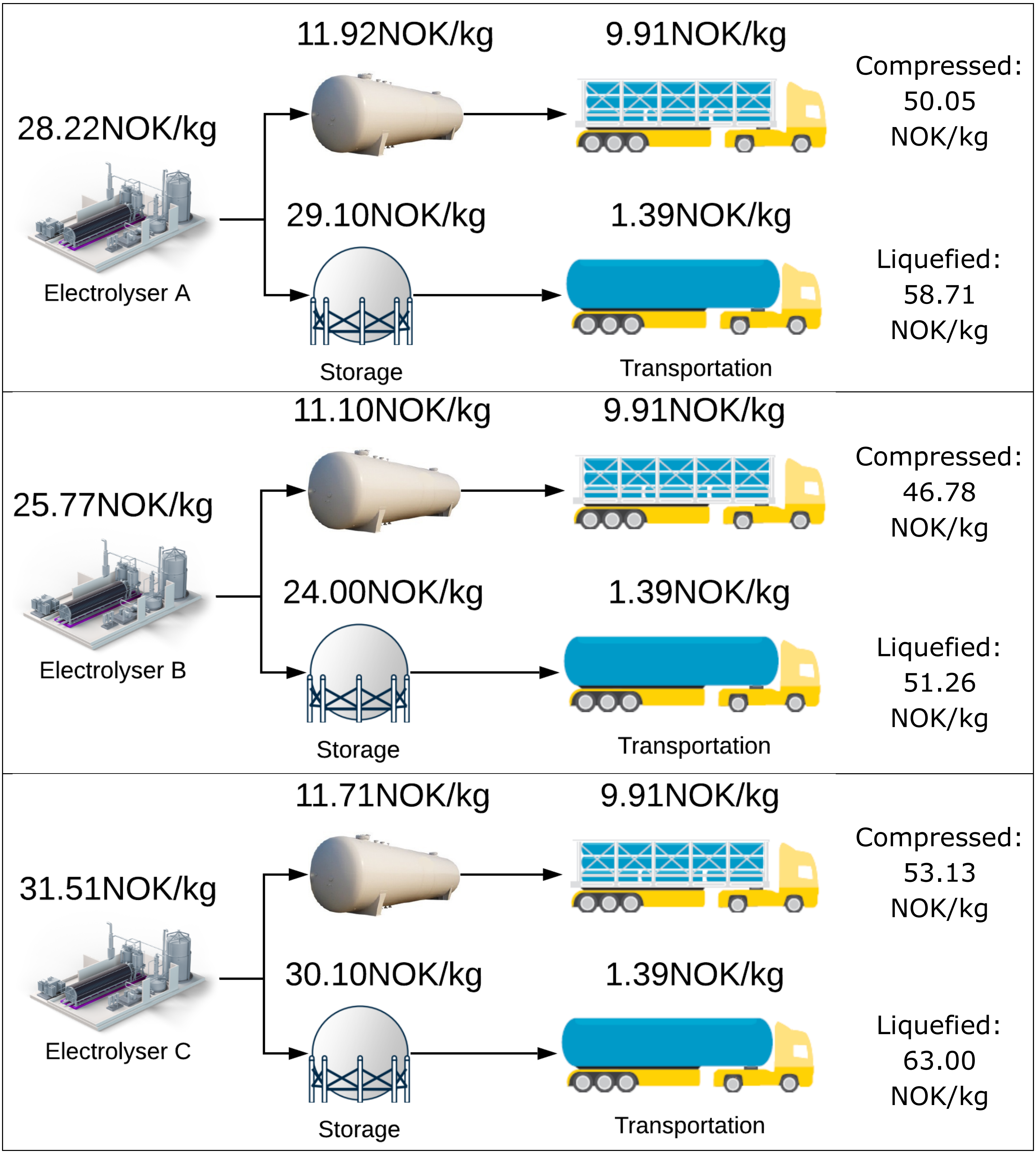

Figure 20 Overview of total cost

3.7 The effect of a changing electricity price

Up until now the cost calculation has been performed by using the average electricity price for the next 10-year period. However, the electricity price is subject to variations. And the price of electricity is paramount for the hydrogen price and it is therefore vital to give an insight into the effects of a changing electricity price. This will allow for a more confident investment decision and give more correct perspective on the feasibility of hydrogen production at Fosen.

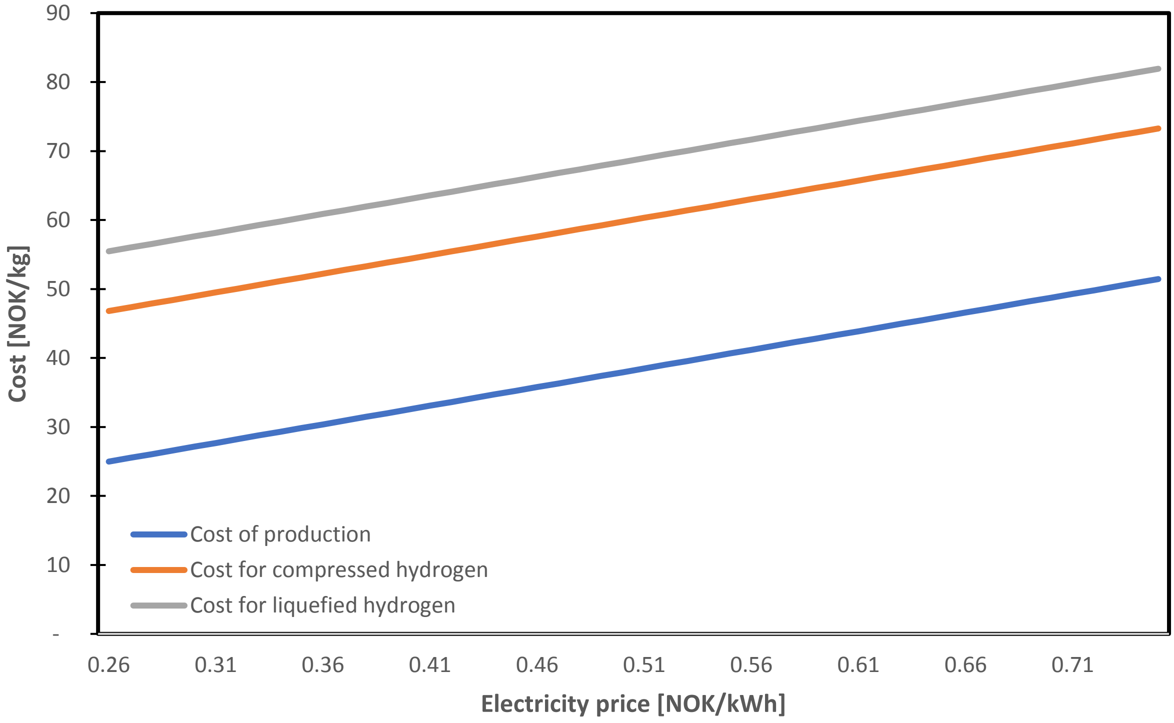

Figure 21 Production cost as function of electricity price for electrolyser A

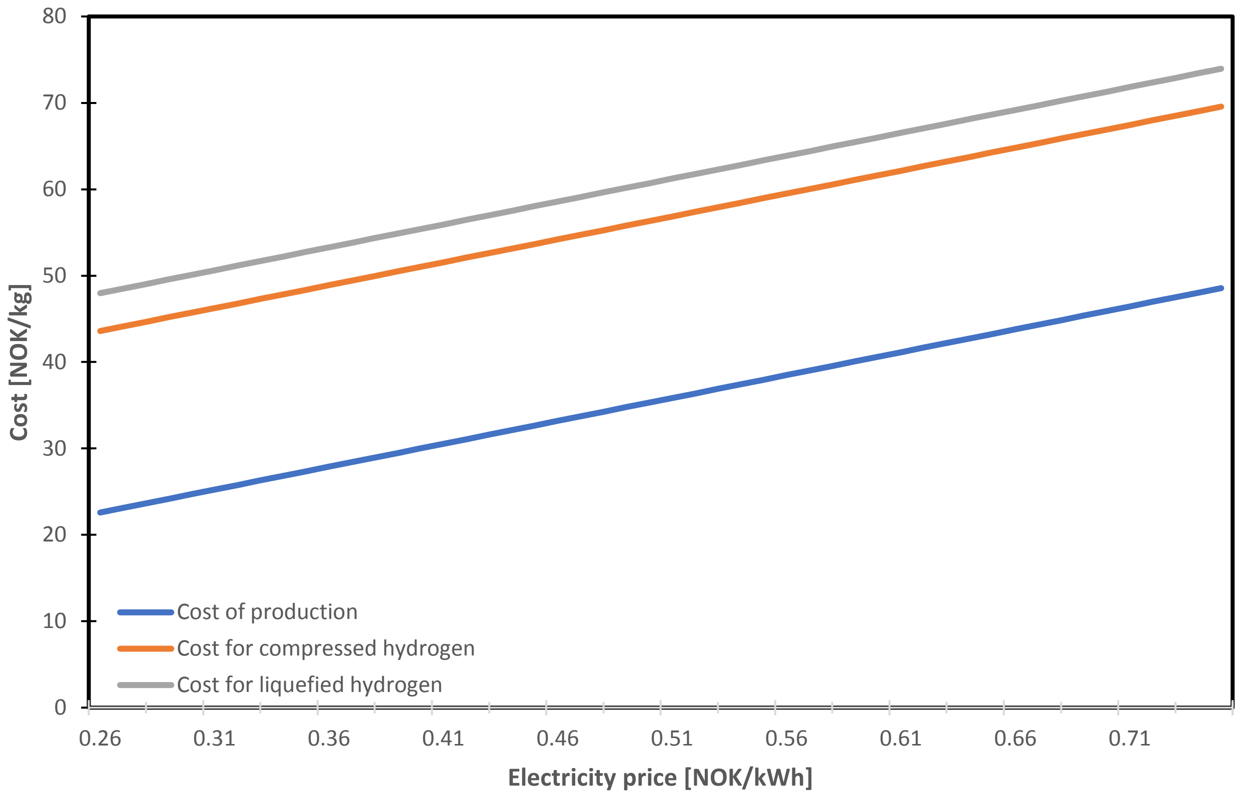

Figure 22 Production cost as function of electricity price for electrolyser B

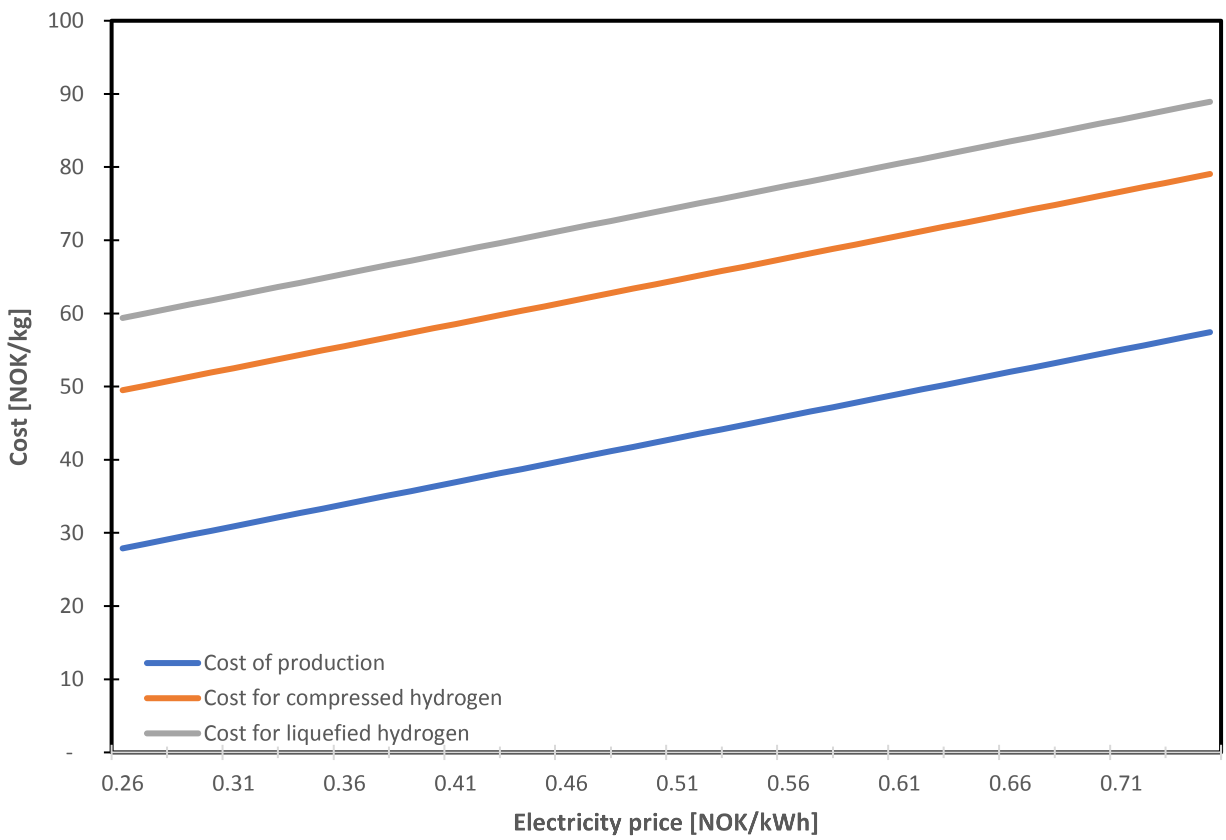

Figure 23 Production cost as function of electricity price for electrolyser C

These estimates show that hydrogen production at Fosen Wind is profitable for a large range of electricity prices. With long-term contracts it should therefore be possible to produce hydrogen at quite a low cost compared to most competitors.

3.8 Cost development with increasing production rate

Chapter 3.3 to 3.5 is a walkthrough of how the average cost connected to each of the three electrolyser options are calculated. This calculation is now developed further by expanding the number of electrolysers up to and including five units of each. That means that there are 216 purchase combinations[22].

Refhyne is currently the largest electrolysis plant in the world. With an installed capacity of 10 MW it produces around 1300 tons H2 per year, or around 3.6 tons per day [108]. This yields some perspective about the probable size of a potential plant but for analytical purposes much larger sizes will also be presented.

It is assumed that transport costs will be reduced linearly with an increasing production rate, until a level where it stabilizes. The maximum cost is the calculated average cost of cost per km per container for one container per trip; 61.9 NOK. The minimum cost is the average cost per km per container for two containers per trip; 40.5 NOK. The average costs are used because there are many potential locations for the hydrogen plant. The maximum cost is used for the smallest production rate which is only an average of 707 kg per day[23], and the minimum cost is reached at 10 containers per day or 5600 kg (560 kg per truck if compressed).

By then multiplying the CAPEX and OPEX of a single electrolyser, assuming 10 percent discount at more than three electrolysers, and 15 percent discount at more than five, decreasing transport costs and the corresponding decreasing liquefaction cost the cost development looks like Figure 24. The discount is assumed because it is reasonable to expect electrolyser manufacturers to want to create incentives for larger orders.

[22] 0-5 of Electrolyser A, B and C gives 6 options for each. That leaves 6*6*6 =216 possible combinations

[23] The average production per day for electrolyser C with the maximum operation time at Fosen of 89 percent as calculated in chapter 3.2

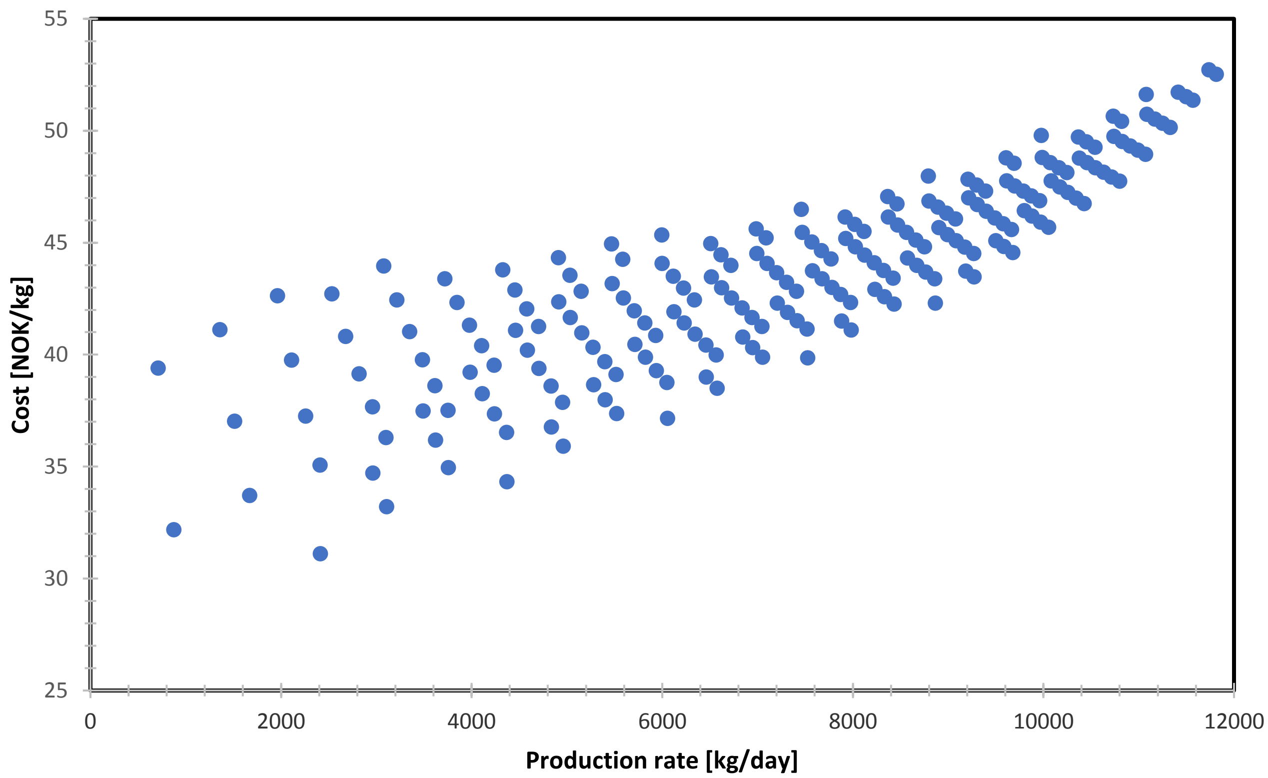

Figure 24 Graph of cost following a decreasing operation time due to higher energy requirements

The cost is increasing but fairly stable up until a production rate of 6000 kg/d but then starts to increase significantly. The stability is due to a falling transport cost up to 5600 kg, while the increase is due to some negative effects. The transport and liquefaction cost and the CAPEX decrease with increasing production rate. But the production as a percentage of installed capacity falls with increasing production rate due to larger power requirements. As the size of the electrolysis plant increases, so does the required power.

It is contra-intuitive to see an increasing cost with increasing production rate. To illustrate the importance of operation time graphs depicting the production for a theoretical wind plant capable of keeping all electrolysers running at 80 percent and 100 percent of the time is presented in Figure 25 and Figure 26.

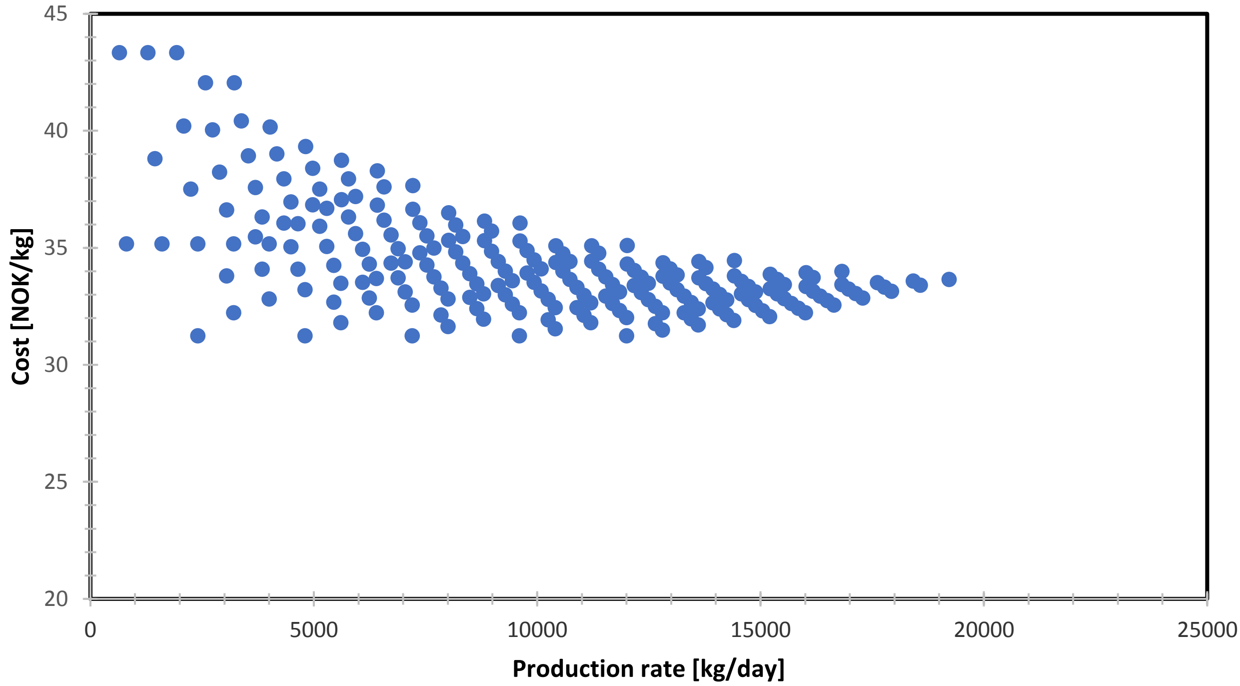

Figure 25 Graph of cost at a guaranteed operation time of 80% of the year

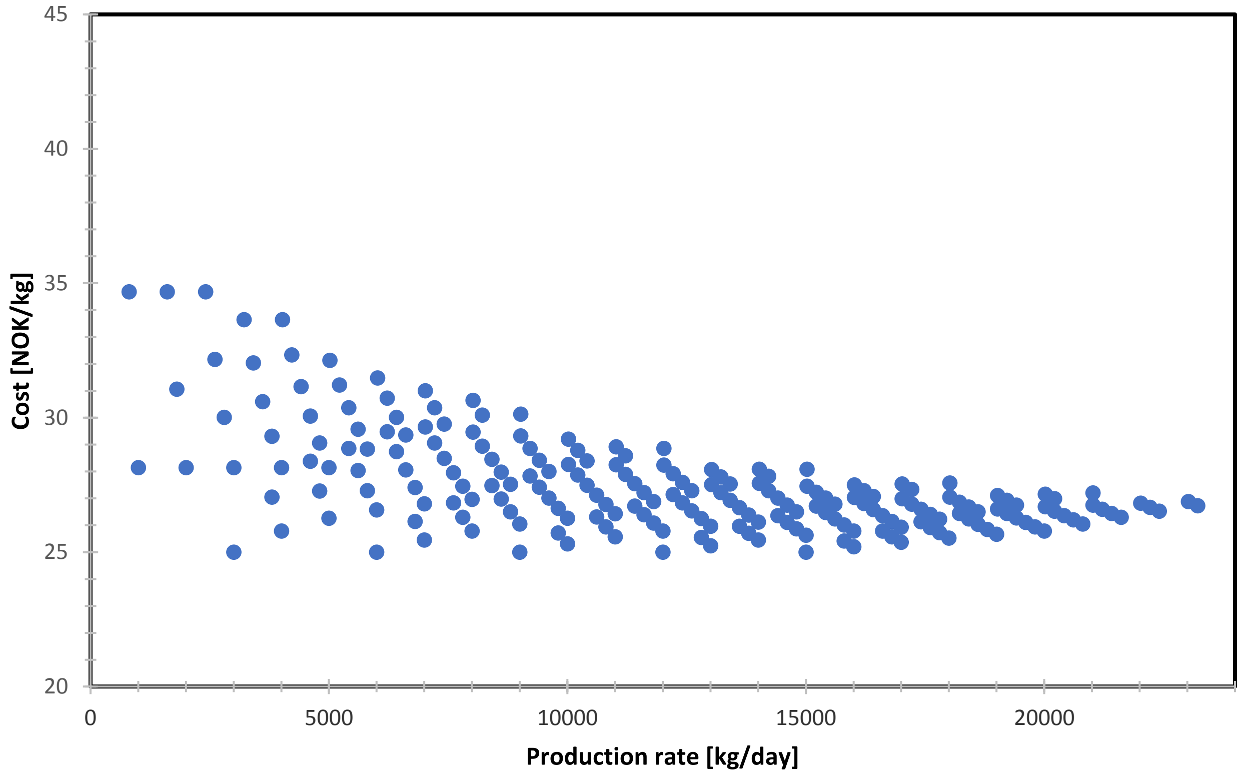

Figure 26 Graph of cost at a guaranteed operation time of 100% of the year

The cost development with non-decreasing production capability follows what looks like a natural cost development when increasing the production rate. Keep also in mind that the actual production numbers would be higher for Figure 24, as Bessakerfjellet had a lower production percentage than all the wind farms at Fosen, and multiple electrolysers mean that there is not necessarily a need to shut all down when insufficient power to all.

Figure 25 and Figure 26 show that the assumptions lead to a natural declining cost with an increasing production rate, but this decrease is undone by the falling operation time. Be also aware that the narrowing of the scatter plot is not due to the calculations being more precise, it is simply fewer combinations of electrolysers that can produce those kinds of production rates.

Chapter 4 Further comments

Besides presenting the calculations regarding cost for production, storage and transport there are several interesting aspects that can inform a research question of whether a hydrogen production facility at Fosen is feasible, some of these aspects will be presented in chapter 4.

4.1 Net present value (NPV)

Net present value is an easy way of assessing investments. It is a profitability analysis which is used to see if an investment is profitable or not. This is achieved by discounting future cash flows to present day value [109] [110].

$$NPV = \sum_{t=1}^{T} \frac{C_t}{(1+r)^t} \tag{8}$$

$C_t = the\ payment\ surplus\ in\ year\ t$

$t = lifetime\ [y]$

The payment surplus is dependent upon the price of hydrogen, which can be determined by market conditions. But to offer an overview of potential profit the NPV is calculated by assuming a hydrogen price of 70 NOK/kg. That is quite a low hydrogen price as Uno-X for instance operates with 90 NOK/kg (see chapter 4.3.2). However, their price is for end consumers buying fuel to their cars. A price of 70 NOK/kg will make all options profitable but at different rates.

	A compressed	A liquefied	B compressed	B liquefied	C compressed	C liquefied
NPV [MNOK]	49.9	28.24	174.23	140.61	33.92	14.08

Table 27 NPV for the different production options

The hydrogen price is set by demand. Hence, Figure 27 show the NPV as a function of hydrogen price.

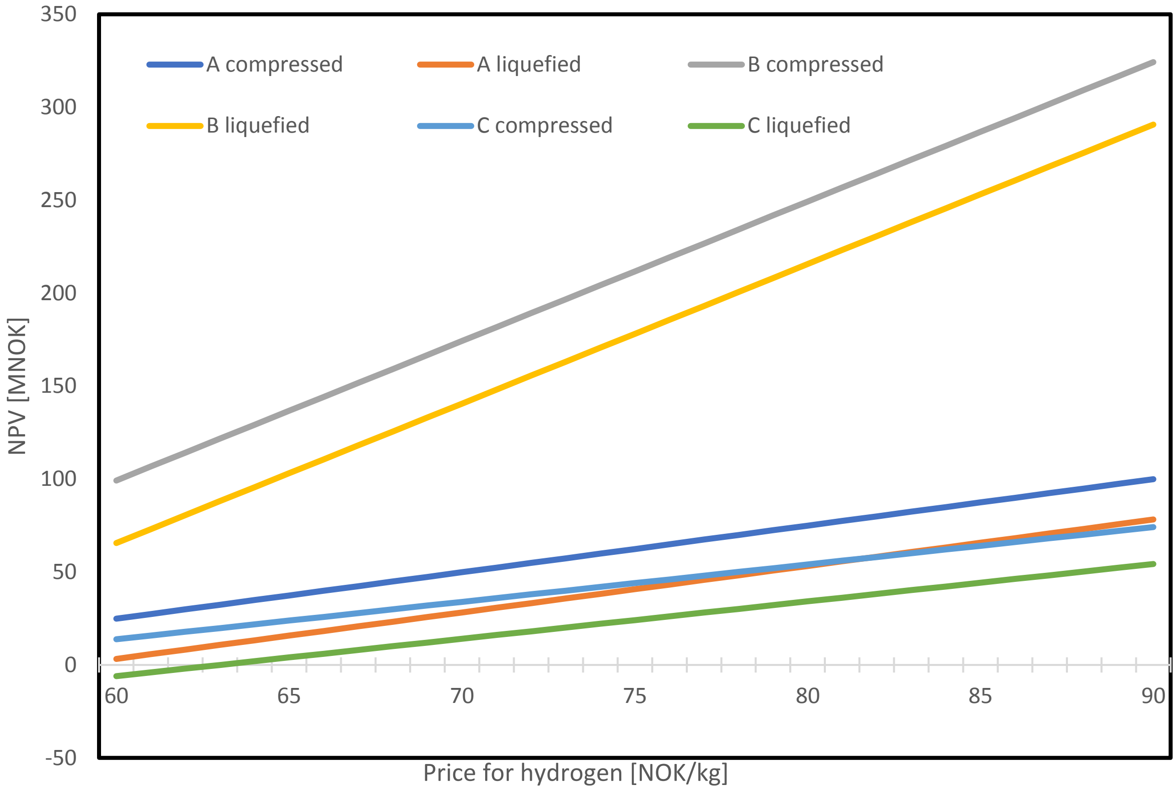

Figure 27 NPV as a function of hydrogen price

The NPV shows that the project is profitable for an array of hydrogen prices. An interesting observation though is that liquefied hydrogen from electrolyser A gives a higher return than compressed hydrogen from electrolyser C when the price is in the 80s.

4.2 Information to improve investment decisions

This thesis' basis is two different electrolysis technologies, PEM and alkaline. In addition to the cost there are other factors which are important to come to a conclusion as to which technology to go for. To provide more insight into these factors this chapter will present projected cost development and a technical comparison of the technologies, compare the storage solutions and the efficiency, present the theoretical production potential and compare the production cost with that of other countries.

4.2.1 Comparison of production technologies

4.2.1.1 Comparison of estimated cost development:

Saba et al. (2018) conducted a literature review of published investment costs of water electrolysers from the 1990s through 2017 [111]. They found that the R&D efforts have led to remarkable cost reductions. In the year 2030 cost projections for alkaline technology ranged from 787 to 906 $€_{2017}/kW_{HHV}$ and between 397 and 955 $€_{2017}/kW_{HHV}$ for PEM electrolysis [111] (see Figure 28). The range of values for the PEM technology is quite large but the lower end is almost half of that of alkaline. This points to PEM's great potential for further cost development.

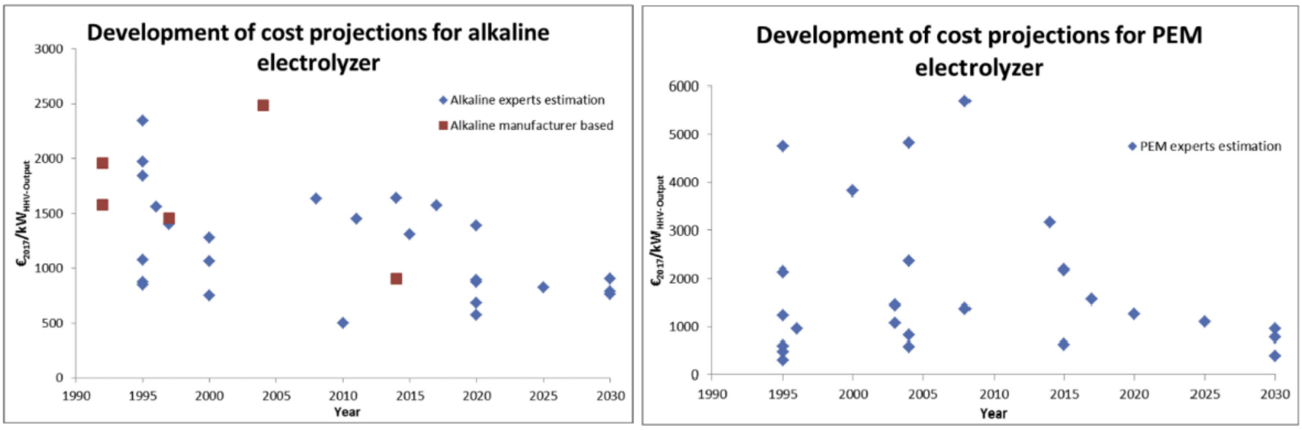

Figure 28 The projected cost development of alkaline and PEM electrolysers for 2030 *[111]*

There are however large differences in estimates for 2030 from different sources. Fraunhofer-Institute projects a cost for *alkaline* in 2030 of 600-1400€/kW, and 850-1800€/kW for PEM [20]. While E4Tech and Element Energy projects a cost of 370-800€/kW for alkaline and 1900-2300€/kW for PEM [20]. Meanwhile, Nel projects a cost of 350€/kW for *PEM* in 2030, and Smolinka et al. (2015) expects the costs of PEM electrolysis to drop below those of alkaline by 2030 [112].

DNV GL on the other hand assumed an electricity cost for a Norwegian commercial customer not including taxes of 0.34-0.67 NOK/kWh in 2020, and 0.38-0.77 NOK/kWh in 2030 and calculated the following cost per kg hydrogen[24] [20].

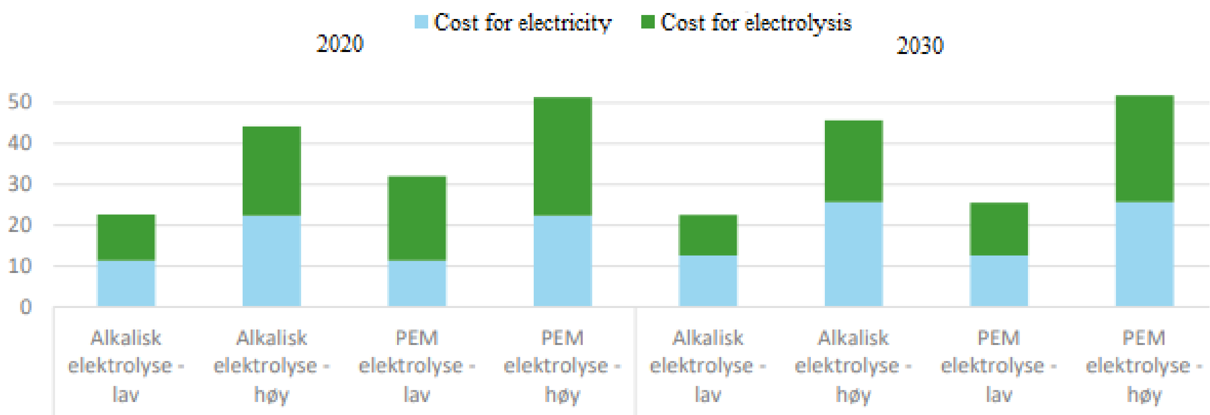

Figure 29 Estimated cost for hydrogen production by electrolysis in Norway, adapted from *[20]*

The calculation divides each technology into a low- and high-cost scenario for the year 2020 and 2030. The difference in high and low costs are due to differences in grid rental costs, and technology [20]. Fosen Wind will be in the lower end of these estimations as there are no grid rental costs and the electricity price is the lower end of the aforementioned span as well. These calculations show an expected negligible drop in costs for alkaline electrolysers in the year 2030 relative to 2020, and a drop from around 32-51 to 25-51 NOK/kg for PEM electrolysis (Column 3 and 4 in each section). This shows that PEM electrolysis is still subject to significant cost reductions compared to alkaline.

[24] “alkalisk” = alkaline, “elektrolyse” = electrolysis, “lav» =low, «høy» = high

It would seem that there are disagreements as to the status in 2030 regarding alkaline versus PEM technology. This makes it less tempting to wait a few years in order to see for instance PEM drop an expected amount of cost before an investment, because it is not certain it will be so. This bodes for avoiding postponement of an investment in hydrogen, and rather position oneself in the emerging market now. When the market position is established a new production strategy can then be outlined when the cost is stabilizing.

4.2.1.2 Technical comparison:
The two technologies represent several pros and cons. In Table 28 a technical summary is given, and in Table 29 the most significant differences are aligned.

	Temperature [°C]	**Electrolyte**	**Efficiency[25]**	**Purity**	**Current density [A/cm²][26]**
Alkaline	60 - 80	Potassium-hydroxid	65 - 82%	99.5-99.9998%	0.1-0.4
PEM	60 - 80	Solid state membrane	65 - 78%	99.9-99.9999%	>1.6

Table 28 Electrolysis technologies compared *[16] [113] [114]*

Alkaline electrolysis	**PEM electrolysis**
Long-term stability	Rapid system response
Well established technology	Large potential for improvements
Commercially used in industry for almost a century	Commercially used for medium and small applications (<300 kW)
Low cost	Expensive
Stacks in multiple MW range	Compact system design
Low current densities	High current densities
Corrosive liquid electrolyte	Non-corrosive solid membrane
Potentially significant impurities: KOH, O_2, H_2O	Only possible impurity of significance is H_2O
Typically only 80-90% turndown and stopping or off-time shortens lifetime	100% turndown and any stopping or off-time extends lifetime
Requires back-up power to safely shut down	Does not require backup power supply

Table 29 Comparison of alkaline and PEM electrolysis *[114] [16] [115] [116]*

Alkaline is cheaper and have a longer lifetime than PEM electrolysers. However, PEM technology cost is widely expected to be reduced over the next few years due to further

[25] Efficiency is defined as the relation between ideal and actual energy needed to drive the reaction
[26] A very high current density is mostly undesirable. Electrical conductors have a finite resistance which means that they dissipate power in the form of heat. The current density must be limited to prevent the conductor from melting or catch fire [179]

development but as mentioned in the previous chapter it is difficult to say by how much. Furthermore, since wind energy is by nature fluctuating it is vital that the electrolysers are able to operate during sudden changes in operating conditions. PEM electrolysers provide an advantage in that they are easier to operate, faster to start up and yields high power and current density and have less severe effects to the quality of the hydrogen. This is important considering the fluctuating nature of wind energy resulting in ~1500-2200 restarts annually (see Figure 14). PEM electrolysers don't require the installation of a back-up power source. This can result in lower CAPEX and OPEX, especially for production units with dynamic energy sources like wind and solar.

Allidéres et al. (2018) found that PEM water electrolysis stacks have the necessary flexibility needed to provide electrical services to the power grid. They can be designed to operate over the entire 0-100 % power range [116]. A PEM electrolyser can respond to a cold start in 5 minutes, and warm start in 30 seconds. Modulation between two points only take 2 seconds. NELs M series of PEM electrolysers have a start-up time of <5 min and ramp-up time (from minimum to full load) of <10 seconds with a ramp rate of >15% per sec [117].

4.2.2 Comparison of storage solutions

In short to medium distances compressed gas is probably advantageous due to the extra cost affiliated with liquefaction. At the moment almost all hydrogen consumption is based upon compressed hydrogen. This makes liquefied hydrogen a future solution for a large-scale deployment of hydrogen or for very heavy transport.

Which type of storage to use is of course dependent on the application, and can be divided as in table 4 according to Ogden et al. (2014):

Application	Compressed hydrogen gas	Liquid hydrogen
Light duty vehicles	X	
Buses	X	
Medium duty trucks	X	
Heavy duty trucks	X	X
Rail		X
Marine		X
Aviation		X

Table 4 Applications of hydrogen liquid and gas, adapted from [118]

As the hydrogen market grows on and the customer base emerges this outline will help guide the strategy choices regarding storage technology.

4.2.3 Comparison of efficiency

Hydrogen production requires energy consumption. Any energy conversion will result in loss of energy and a reduced efficiency. The effectiveness of hydrogen production is decided by the amount of energy consumed to produce a certain amount of energy in hydrogen form. It is crucial that all calorific values are lower heating value so as to be comparable. Hydrogen has a lower heating value of 120.21 MJ/kg [119].

The efficiency is calculated by using the following formula:

$$\eta_{electrolyser} = \frac{energy_{out}}{energy_{in}} = \frac{energy_{hydrogen}}{energy_{electricity}} * 100\%$$

$$= \frac{Energy\ content_{hydrogen}[\frac{kWh}{kg} H2] * Production_{hydrogen}\ [kg\ H2]}{1000\left[\frac{kWh}{MWh}\right] * Energy\ consumption_{electrolyser}\ [\frac{MWh}{day}]} * 100\% \tag{9}$$

Which yields the following table

	Type	Size [kg/day]	Power consumption	Efficiency
Electrolyser A	Alkaline	1,000	2.3	60.38 %
Electrolyser B	Alkaline	3,000	6.8	61.27 %
Electrolyser C	PEM	804	2.04	54.73 %

Table 30 Efficiency of electrolysers

This table shows that the efficiency increases with larger production units, and alkaline is more efficient than PEM [119]. The efficiency will be reduced further due to energy required for compression of liquefaction. E4Tech and Element Energy estimated that energy efficiency will be 62-74% in 2030 [20], and Li (2008) operates with an efficiency of 70% [120] [121].

The efficiency is hence in favor of alkaline technology at the moment. The difference also illustrates the importance of choosing ones' battles when introducing hydrogen fuel in large-scale. A conversion to hydrogen will represent a loss of consumable energy, and it is therefore important to utilize hydrogen where hydrogen is advantageous to batteries. This involves long-distance and heavy-duty transport and marine activities like ferries, speedboats and cargo ships.

4.2.4 The complete hydrogen production potential

In order to illustrate the complete potential of hydrogen production at Fosen the maximum production is calculated and then the number of vehicles this amount of hydrogen can fuel is calculated. It is not an economic calculation, it is simply a calculation illustrating the shear production capacity at Fosen if the necessary decisions were made.

Fosen Wind has an installed effect of 1057 MW and a production of 3.6 TWh per year. By assuming that the wind park will limit the number of electrolysers to an amount which allows for an operation time of at least 60% of the year, the potential number of electrolysers can be calculated. From there the total hydrogen production potential can be calculated. This shows that the different wind farms have the capacity to operate the following amount of electrolysers at least 60% of the year if similar conditions as averaged at Bessakerfjellet:

	2.3MW Alkaline	6.8MW Alkaline	2.02MW PEM
Storheia	14	4	15
Geitfjellet	8	2	10
Harbaksfjellet	6	2	7
Hitra 2	4	1	5
Kvenndalsfjellet	5	1	6
Roan	12	4	14
Total	**49**	**14**	**57**

Table 31 The maximum electrolyser potential a limit of 60% operation time

This results in the following production per year (see Figure 30).

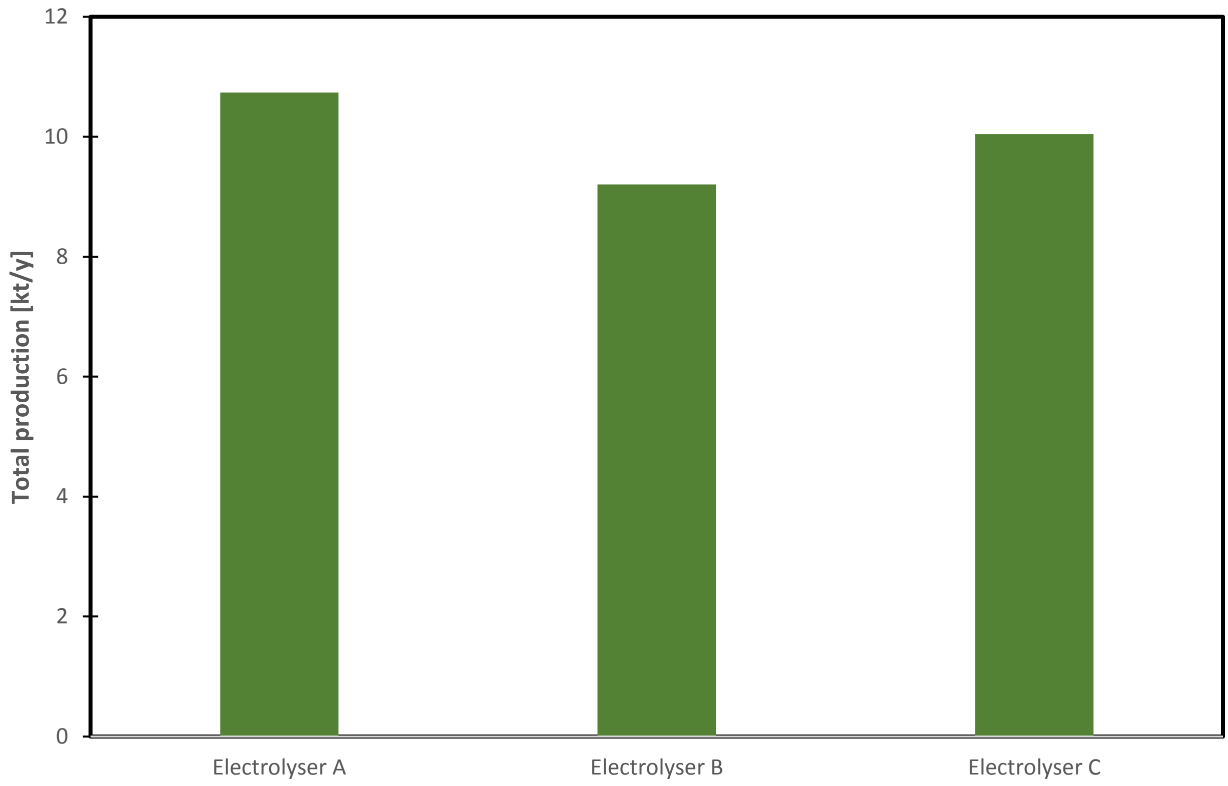

Figure 30 The total hydrogen production at Fosen when combining all wind farms

It would be possible to make a combination of different sized electrolysers in order to optimize the production, but as this calculation aims to illustrate the potential that has not been done. The average production of 10 million kg per year is enough hydrogen to supply the following number of vehicles for one year:

Type of vehicle	Number of vehicles in Norway	Distance traversed per year [million km/y]	Distance potentially covered by hydrogen [million km/y]	Percentage of total park covered
Personal car[27]	~2.8 million [28]	~34000	~1000	2.91%
Trucks[29]	~72 400	~2600	~122	4.69%
Buses[30]	~15 600	~550	~125	22.94%
Ferries[31]	100+ [32]	-	-	-
Speedboats[33]	~100 [34]	-	-	-

Table 32 The number of vehicles potentially fueled by hydrogen produced at Fosen

This calculation show which enormous potential Fosen theoretically possesses. Fosen have the capacity to become a hydrogen hub for off- and onshore hydrogen activity for Central-Norway.

4.2.5 International comparison

Norway's large power capacity leads to low power prices. As shown in Table 33, power cost constitutes 56-66% of the total levelized cost of electrolysis calculated in this thesis. That means that Norwegian power prices will lead to cheaper electrolysis and hydrogen.

	Percentage of cost due to electricity
Electrolyser A	61.28 %
Electrolyser B	65.87 %
Electrolyser C	56.81 %

Table 33 Percentage of cost due to electricity

To make a point of reference the projected electricity prices for Denmark, France and Germany has been obtained (see Appendix I). By finding the average of the given period the projected electricity price is

	Denmark [NOK/kWh]	France [NOK/kWh]	Germany [NOK/kWh]
Average	0.38	0.48	0.46

Table 34 Projected electricity prices for Denmark, France and Germany

With these electricity prices and assuming that the other costs will be the same as in Norway, the production cost for the three electrolyser options will be as follows:

[27] Average driving distance of 12400 km/year [160] and 10 km on 100 g H2 [125]
[28] [173]
[29] 400km per 32.86 kg H2 [161] and an average of 35 796 km per year [162]
[30] 8 kgH2/100 km [163] and an average of 34 836 km per year [162]
[31] 150 kg H_2/d for MF Ole Bull [168], 66 departures/d [169] and a distance of 2.2 km [170]
[32] The number of ferry services, not ferries. The average number of ferries for each service is unknown [174] [175]
[33] Trondheim-Kristiansund 400 kg compressed H2 one way [171] and three departures per day [172]
[34] [176]

Per kg	Denmark	France	Germany	**Norway**
Electrolyser A	31.46	36.86	35.78	**28.22**
Electrolyser B	28.95	34.25	33.19	**25.77**
Electrolyser C	35.12	41.15	39.95	**31.51**

Table 35 Hydrogen cost compared to other countries

That leads to a significant cost reduction in Norwegian favor compared to these countries:

Difference	Denmark	France	Germany
Electrolyser A	+3.24	+8.64	+7.56
Electrolyser B	+3.18	+8.48	+7.42
Electrolyser C	+3.61	+9.64	+8.44

Table 36 Hydrogen cost [NOK/kg] compared to Norway

This illustrates another major advantage that Fosen wind possesses regarding hydrogen production. When the cost can be significantly lower than potential markets as Denmark, France and Germany, it is possible to envisage a future export market. When the cost is significantly less is may be cheaper to import hydrogen from Norway despite increased transport costs than to produce it themselves.

4.3 Information to check assumptions

The calculations in this thesis would not be possible without assumptions due to uncomplete data. To check these assumptions some comparisons of data is possible, and that will be presented here. In addition, the share of the total cost that OPEX constitutes was found to be very reasonable in chapter 3.3.2.

4.3.1 Comparison with available CAPEX data

Despite market actors being restrictive with financial data some scientific articles and project reports operate with CAPEX of electrolysers on a €/kW-basis. These data are an effective way of checking the calculations and examples used in this thesis.

However, it is often unclear exactly which expenses are included in CAPEX for production. In one sense it makes sense to include the compressor and battery since it is vital for producing hydrogen of sufficient quality. But it is feasible that many electrolysers will use grid-assistance and not batteries. That will not be accounted for in the CAPEX but the OPEX. Hence, the CAPEX for electrolyser including battery and compressor is shown in Figure 31, while the only the CAPEX for the electrolysis equipment is shown in Figure 32.

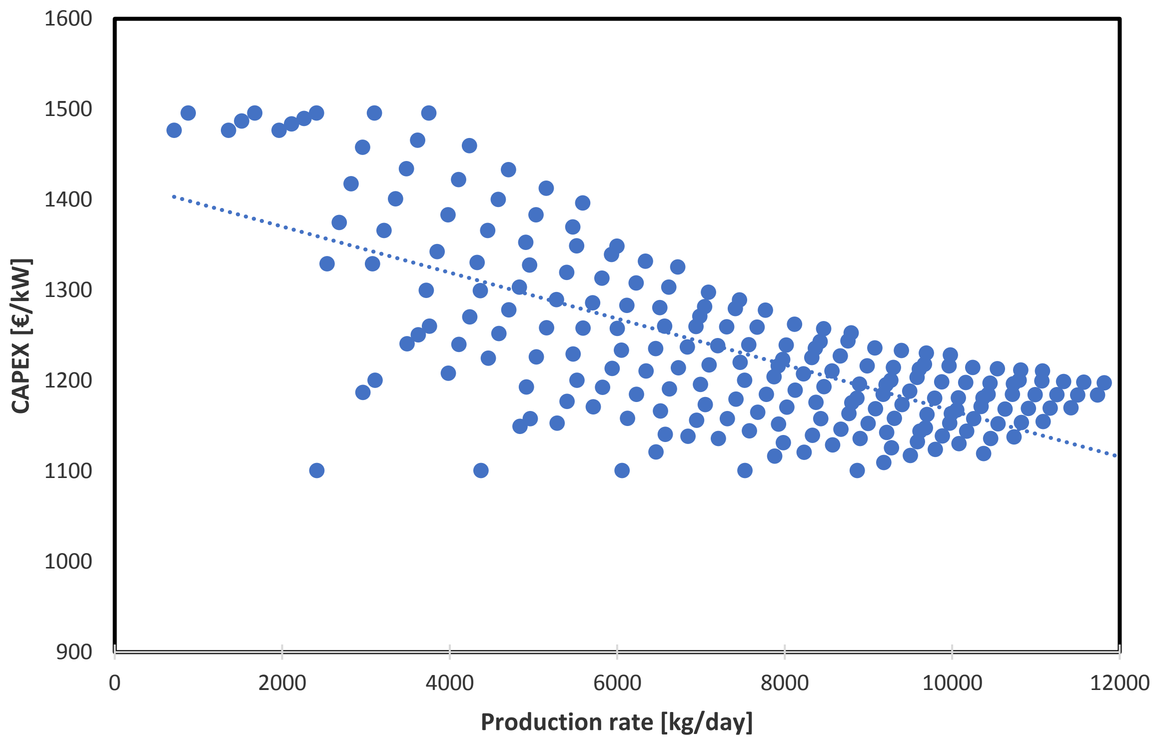

Figure 31 Cost development due to larger production rates (battery and compressor included)

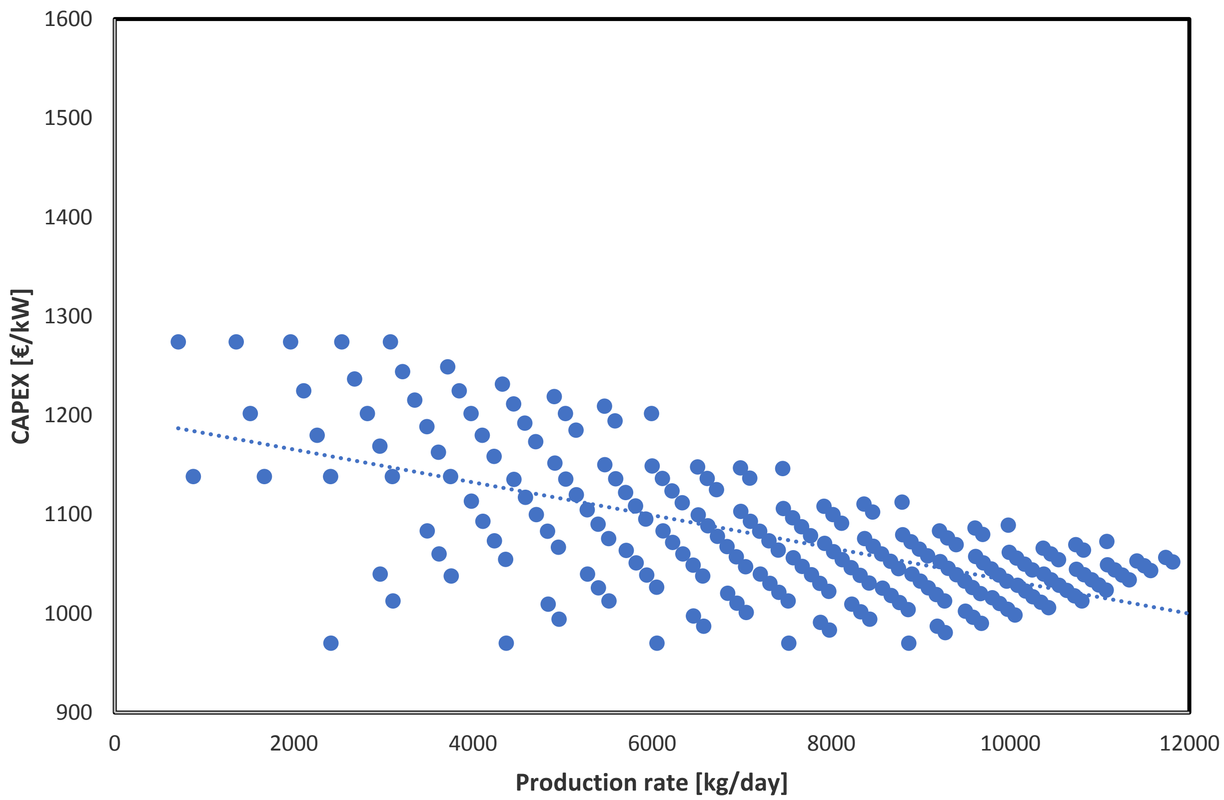

Figure 32 Cost development due to larger production rates (battery and compressor excluded)

For the graph showing the CAPEX excluding battery and compressor the cost lies in the range of 970 to 1280 €/kW. That value range can be compared to cost data in the data set extrapolated from several sources. Keep in mind that the narrowing of values in the highest production rates are not due to higher accuracy, but fewer combinations of electrolysers reaching those production rates.

CAPEX of electrolyser [€/kW]	Source	Type of electrolyser	Note
250-1270 (2030)	[20]	PEM	E4Tech and Element Energy
350 (2030)	[20]	PEM	
370-800 (2030)	[20]	Alkaline	
600-1400 (2030)	[20]	Alkaline	Fraunhofer-Institute
650 (2020)	[20]	PEM	
700-1130	[122]	Alkaline	
700-1250	[20]	Alkaline	Nel 2014 15 bar + commissioning
740-1300	[20]	Alkaline	IEA 2015
800-1300	[122]	PEM	
840	[64]	Alkaline	
850	[20]	PEM	
850-1800 (2030)	[20]	PEM	Fraunhofer-Institute
930	[64]	Alkaline	
970-1140	Info from market actor	Alkaline	
1000-1200	[20]	Alkaline	E4Tech and Element Energy. Not including installation
1010	Info from market actor	PEM	
1300	[71]	Alkaline	
1460-1492	[70]	Alkaline	450 and 545 kW electrolysers
1486	[64]	Alkaline	
1720	[64]	Alkaline	
1900-2300 (2014)	[20]	PEM	E4Tech and Element Energy

Table 37 CAPEX from different sources

The values are within quite a big span, from 250 to 2300 €/kW. However, some of these values are projections for 2020 and 2030. If we only look at the data for the current state, the span is 700 to 1720 €/kW. The calculated data lies in a span right in the middle of those sources. That means that the calculations will be in the right order of magnitude, and the fact that the unrelated data from different sources are in the same ballpark as the data used for this thesis strengthens the reliability of the results.

4.3.2 Comparison with hydrogen cost in literature

Another source of comparison is the price and the cost of the produced hydrogen. This will contextualize the cost calculations for Fosen and put into perspective its economic strength and provide insight into the profitability of a hydrogen production at Fosen Wind. Table 38 show the cost from several sources. Cost is the production cost without the margins for profit included. Table 39 on the other hand show the price, which is what customers would pay. This is of course dependent upon the margins of profit that is chosen but it is an indication of the profitable range.

The cost for hydrogen:

Source	**Cost [NOK/kg]**	**Cost per 10 km[35] [NOK]**
[123] Kumar et al.	88.79	8.9
[16] Fischedick et al	38.96-116.88(now), 29.22-58.44 (projected)	3.9-11.7
[124] Greensight	72.3-74.5[36]	7.2-7.5
[61] Mohsin et al.	37.1[37]	3.7
[20] DNV GL	15 (potentially) [38]	1.5

Table 38 The cost of hydrogen in literature

Price to give the normal gross profit:

Source	**Country**	**Price [NOK/kg]**	**Price per 10 km [NOK]**
[125] Uno-x	Norway	~90	9
[126] CAFCP	USA	120.6	12.1
[127] H2 Suedtirol	Italy	109.96	11
[124] Greensight	Norway	87.0-99.4[39]	8.7-9.9
[124] Greensight	Norway	69.3-79.1[40]	6.9-7.2
[124] Greensight	Norway	59.7-67.9[41]	6.0-6.8
[124] Greensight	Norway	56.0-61.8[42]	5.6-6.2
[8] Glenk & Reichelstein	Germany, USA	31.46[43]	3.1

Table 39 The price of hydrogen in literature

The information from [124] is especially interesting as this is a calculation for a hydrogen project at Gloppen, Norway. In this report from Greensight the production cost and price are calculated for a daily production of a few hundred kg. The calculations done in this thesis give a cost of the same order of magnitude but less expensive. That is reasonable considering that the production rates in this thesis are higher than at Gloppen, but could also be a sign that results are too low. When put into a graph this comparison gives a

[35] ~10 km on 100 grams H_2 [125]
[36] At a production rate of 145 kg/d
[37] At ap production rate of around 2.5 tpd
[38] At a power price of 0.26 NOK/kWh
[39] At a production rate of 145 kg/d
[40] At a production rate of 207 kg/d
[41] At a production rate of 270 kg/d
[42] At a production rate of 327 kg/d
[43] The break-even cost for hydrogen in Germany

better overview. The calculations from this thesis don't have transport and storage included in the graph (see Figure 33) since the cost from the sources are only the production itself.

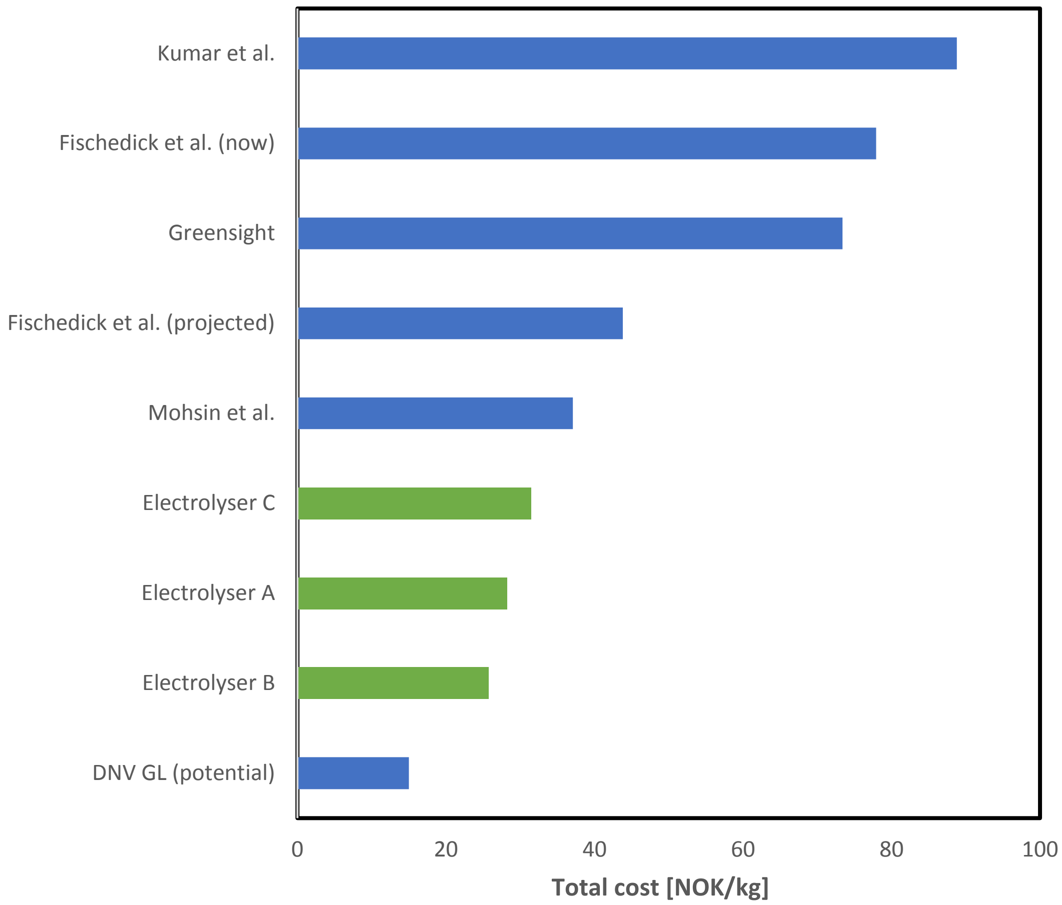

Figure 33 Comparison of total cost (thesis calculations in green)

The graph shows that the calculations are low, which on the on hand is plausible because of the very advantageous conditions at Fosen. On the other hand, it could also be a sign of some expenses lacking or being underestimated. However, the projected potential cost calculated by DNV GL is almost half of the cost of electrolyser C. This show that the calculations don't necessarily are too low. Fosen and TrønderEnergi simply have several advantageous characteristics which allow for a low hydrogen production cost.

4.4 Further discussion

The research question for this thesis is:

Can Fosen Wind produce hydrogen at a market competitive cost?

As mentioned, this research question requires several assumptions and they have a varied degree of justification. In this section those assumptions and the results they lead to will be discussed.

4.4.1 Unclear data and sources

A lot of the source data used to complete this thesis are themselves results of assumptions and do not always clearly state which assumptions, or what is included in the data. It is rarely stated whether salaries are included in transport related costs, or what is included in CAPEX cost, or the cost of cell-stacks to mention some. These shortcomings in data means that the calculations in this thesis require some assumptions build on other assumptions in order to end up with a calculated cost result. Such a data basis will potentially skew the results and thereby decrease the reliability of the results and conclusions.

However, several measures have been taken to try to deal with this obscurity. It has been dealt with by finding similar costs in literature (see chapter 4.3) to check that several parts of the calculation are of reasonable orders of magnitude, checking other relations like the fraction of the total cost constituted by OPEX (see chapter 3.3.2) and seeing that the cost per kg hydrogen is in accordance with NEL's target (see chapter 3.3.2).

However, the calculated end cost is very low. This can be due to Fosen's favorable qualities for hydrogen production. But it is also an indication of possible lacking costs, or sources underestimating the true cost. A potential lacking cost is the cost of evaporated liquefied hydrogen or the shipment containers. These kinds of "shortcuts" were necessary and taken when seeming reasonable. E.g. the cost of evaporated liquefied hydrogen can be regained to some extent, and the losses are only a few percent and assumed negligible (0.1-1%). Furthermore, the calculations used the most expensive source when in doubt, or used the average value calculated from a dataset, which decreases the possibility of the end-cost being too low. This reduces the risk of overestimating the potential pay-off.

Another issue is the state of the hydrogen industry. The hydrogen industry and its associated technology is growing fast and in several countries. In such a rapid development, projections are difficult, and the overall picture is changing constantly. That means that sources from just a few years ago can potentially be wrong or yield a wrong impression of the current state. In addition to the possibility of a fuzzy overall picture the actors constituting that picture benefits from skewing the information in their favor. Most of the anonymous sources in this thesis are market actors. It is possible that they have incentives for supplying data from the positive end of the spectrum, strengthening the potential of hydrogen. In addition, different suppliers may give information with different content in agreements and contracts. In combination these factors make it difficult to give a result of high reliability and utility. The obscurity of the industry requires a restrained conclusion, which makes the conclusion more diffuse, thereby reducing the utility of it.

4.4.2 Suboptimal assumptions

It is suboptimal for calculations to use assumptions at all, but not always to the same degree. As mentioned in the previous chapter some assumptions are simply necessary to get to a result. But some assumptions or ways of calculation in this thesis led to counterintuitive developments as well. For instance, the calculation of the OPEX related to storage the basis is that the cost requires 9-12% of the energy in the final hydrogen. This means that mathematically there is nothing to gain from increasing the production rate – which is unlikely. Generally speaking, large scale is less expensive than small scale. A lot of the assumptions available in the hydrogen industry are rules of thumb which will skew the overall picture. Furthermore, these rules often don't explicitly state the production rate they assume for instance. When the rules of thumb express linear relationships this weakens their accuracy and lead to counterintuitive developments like the one mentioned above - financial development is rarely linear.

Another example is the cost of storage which was calculated by using the cost per kg, and the amount was determined by the transport rate. The assumption that there would be a constant and fairly regular transport led to electrolyser A and B requiring the same storage despite B producing thrice the hydrogen of electrolyser A. This difference was accounted for in the increased transport frequency but can give an unfortunate impression.

In literature most reports have used a Weibull distribution to simulate data for wind parameters for instance. A Weibull distribution is a continuous probability distribution often used to examine life data through distribution parameters. Instead, this thesis uses data from a similar wind park called Bessakerfjellet. This has been the basis for calculating the probable production and the number of forced shutdowns. These are simplifying assumptions which would benefit from more accurate data of the conditions at Fosen. However, that data was only used to give an indication of the technical conditions. The actual operation time will actually be larger than the one used during these calculations. Hence, this assumption will also avoid overestimating the hydrogen production potential at Fosen Wind.

4.5 Strategy alternatives

There are several reasons for and ways to commence a hydrogen production [48]. The research in this thesis can shed light on some of these alternative strategies. That will be done shortly in the following sub-chapters.

4.5.1 Hydrogen as fuel or feedstock

Norway possess large on- and offshore wind resources. In Norway most onshore wind power potential can be found along the coastline. Hydrogen production for ferries and other naval traffic is therefore a natural combination. In addition, several large Norwegian cities are located at the shore and can therefore also become hydrogen hubs for heavy-duty marine and land transport. In this respect Norway is ideal for a hydrogen fuel focus. Marine activities can easily be coupled with heavy-duty trucks and industrial machinery, and thereby gradually increase the volume of hydrogen consumption. The calculation for the percentage of the Norwegian trucks and buses a hydrogen production at Fosen could cover also illustrated this potential. By utilizing more of the renewable power potential along the Norwegian coast a well-distributed hydrogen infrastructure can help remove carbon emissions in marine sector.

However, it is important to be aware of which battles to fight. Norway has a very well-developed power infrastructure, with a strong electric vehicle base. It will be wise to let batteries continue to power those vehicles and routes where batteries are sufficient. A hydrogen fueled car will use 30-35% of the original energy content for propulsion of the vehicle [128] [119] [129]. Batteries on the other hand have an efficiency of around 90 percent, and 80 percent when including the process from electricity to movement [130] [119].

In addition to the hydrogen, this system will produce quite large amounts of heat and oxygen (8-to-1 relationship to the hydrogen). With connection to the right industries this can represent a profit. In Hirth (2018) heat is assumed to be worth 0.60 NOK/kg H_2 [124].

Hydrogen fuel can therefore also represent income and mitigation measures for oxygen and heat demand.

4.5.2 Hydrogen production by excess power

A hydrogen production unit is often launched as a way of storing the power production when it is above the concurrent consumption [8]. This will however only be profitable under specific circumstances. As Figure 25 and Figure 26 show (80 and 100 percent production) electrolysis require quite a large operation time to be profitable. Using excess power, or peak-shaving, does therefore not seem as a feasible strategy. The CAPEX is simply too large. In order to illustrate this graph for a production time of 20 percent was produced:

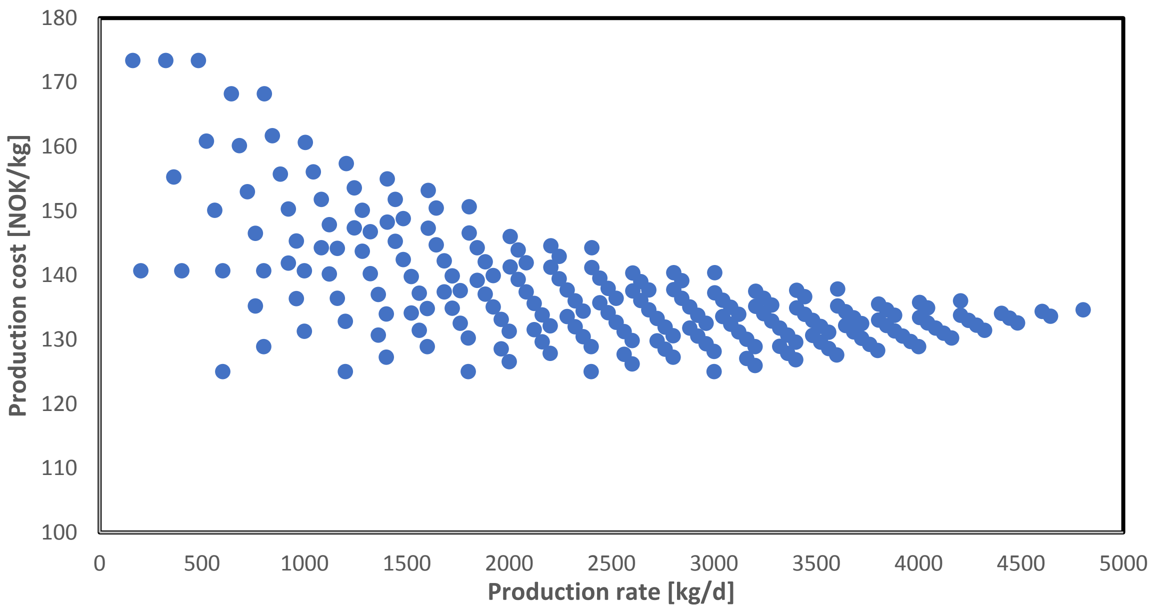

Figure 34 Production cost at peak-shaving, which is production at an average of 20%

As the graph shows the cost at 20 percent operation time per year (around 1750 hours) will in a 15-year scope result in a production cost way above the profitable range. It is possible that the reduced production time will increase the lifetime. But that the lifetime will be increased so drastically as to make up for the reduced production time seems very unlikely. Proost (2018) also states that this isn't a viable solution due to the number of hours of production needed annually to justify the investment [122].

4.5.3 Store electricity in hydrogen in times of low prices

The idea of storing excess power in hydrogen when prices are low, and then using it to produce power when the prices are high has been suggested by some actors [48]. Despite large fluctuations in electricity prices and the long-time storage potential of hydrogen such an option seems unfeasible. As shown in chapter 4.2.3 the loss of energy is too big. Power-to-hydrogen conversion represent an energy loss, a second conversion back to power will further decrease the remaining energy. The purchase of equipment to produce hydrogen seems way too expensive to justify such an investment strategy.

4.5.4 Locally produced hydrogen

As the transportation cost is so large, a feasible strategy for compressed hydrogen is to produce hydrogen in many smaller local production units. Norway is a country dominated by marine activities with all major cities being located with connection to the sea. A stepwise development of hydrogen production across the Norwegian coastline is a prudent way of establishing a zero-emission marine sector. This will ensure short transportation distances, and effectively maximize the amount of hydrogen used for propulsion of vehicles. As hydrogen production units are very modular it is very feasible to create specifically designed hydrogen hubs with a fitting production rate.

Liquefied hydrogen however will require larger production rates than what several local hydrogen hubs entail. When the demand of liquefied hydrogen is sufficient, larger liquefaction plants can be constructed. Large enough to allow for profitable liquid hydrogen. In that regard Fosen, centrally located in Norway with a well-developed infrastructure in all directions, is a very viable location.

Chapter 5 Conclusions

This thesis has investigated the cost related to producing hydrogen by wind powered electrolysis at Fosen. Included in that assessment is the CAPEX and OPEX of the production units and storage facility, and the transport to a suitable hydrogen hub. This has been assessed by basing calculations on data received from market actors and by using available scientific and other public sources. By comparing these calculations with similar assessments done by scientific articles and project reports the credibility of this work was assessed and the results put into perspective.

The calculated results seem to be reliable as they fit into cost and price calculations from scientific articles, reports and company websites. However, throughout the research to this thesis it has become apparent that the hydrogen industry is relatively speaking quite new and growing. Hydrogen is not a new fuel or idea, but it represents a new industry and infrastructure when scaled up. There exist rather large discrepancies in source material in hydrogen cost and price estimations, both for the present and for projections towards 2030. Further significant developments are expected, and this introduces another variable of uncertainty regarding the premises for the calculations. There is also little direct experience with hydrogen in Norway and abroad, and many possible market actors and customers are only working on future projects or have only completed preliminary research. In sum this provide an unclear picture for drawing a conclusion to the research question:

Can Fosen Wind produce hydrogen at a market competitive cost?

The functional unit was defined as 1 kg of hydrogen produced and delivered to Brattøra. The different electrolyser options have all resulted in a cost for compressed and liquefied hydrogen transported and delivered to Brattøra. The calculated results yield specific numbers regarding total cost but should be interpreted as indicative, not precise cost estimations. The network of assumptions, aforementioned sources of unreliability, and rules of thumb allows for the calculation of a cost but decreases the accuracy of the result.

However, despite not being able to give a decisive, reliable cost of producing hydrogen, the cost falls within an order of magnitude which points to Fosen producing hydrogen at a market competitive cost. By providing points of comparison for reasonable costs, international prices and for different electricity prices this thesis finds that a hydrogen production facility at Fosen could produce cost competitive hydrogen both for the national and the international market. It is just not able to confidently determine at exactly what cost.

Wind-powered electrolysis at Fosen will produce hydrogen at a very low break-even cost. Due to some necessary simplifications, however, the actual cost will probably increase somewhat from the calculated one when the exact location of the hydrogen hub is determined. An exact location will allow for more precise calculations of costs related to property, safety measures, further transportation and so on. Furthermore, the total cost shows that large-scale production at Fosen is only advantageous up to a certain production rate. It is vital to maintain a sufficient operation time and corresponding production rate to justify the investment. If the power requirement gets too large the power production at Fosen will simply not be sufficient. The per kg cost of hydrogen will hence increase if the production rate exceeds a threshold value. However, that value is so large that is should not pose an actual risk to a hydrogen production facility in any foreseeable future. For all intents and purposes Fosen Wind will be able to produce cost competitive hydrogen.

Electrolyser B gives the lowest cost per kg, but only if the operation time is kept high enough, and it includes the disadvantages of alkaline electrolysers. A PEM electrolyser larger than electrolyser C would therefore seem like the most advantageous option.

Furthermore, hydrogen production by electrolysis will also entail producing an energy carrier from another energy carrier, resulting in energy loss (see chapter 4.2.3). Norway has a well-developed power infrastructure and the largest electrical vehicle fleet in the world. Despite the political incentives for EVs (Electric Vehicles) are slowly being revoked by the Norwegian government they still experience a solid market share due to an expanding recharge infrastructure and EV acceptance. Hydrogen actors must therefore aim at introducing hydrogen in suitable sectors to avoid competing with renewable, established energy alternatives like batteries. However, where hydrogen outcompetes batteries, e.g. in marine activities and long distance and heavy-duty road transport, hydrogen should be a part of the environmental change mitigation effort.

The main strength of this thesis is the way fresh data from several relevant market actors are combined into assessing a specific project's hydrogen producing potential. This decreases the probability of an increasing margin of error as assumptions build upon assumptions to calculate the end-results. The initial data is reliable and relevant which increases the accuracy of the end-results. It also puts the work of this thesis in a strong position as it has utilized information few reports have had access to earlier. In addition, this thesis is quite limited in scope and scale compared to many hydrogen research reports thereby increasing the confidence of the conclusion.

Wind powered hydrogen will allow for renewable energy to reach end-users on a broader, larger scale than before. It will help introduce new tools to reach the mitigation targets and offer a new low-carbon option to the Norwegian transport sector. Furthermore, it will make Fosen Wind engage in a new exciting industry which can produce an entire array of jobs and other new possibilities. Fosen possesses the capacity to be a part of that industry by producing hydrogen at a low break-even cost, at a central, well-developed location in Norway. In sum, a hydrogen production facility at Fosen seems to be a "win-wind" situation for Fosen Wind and Norwegian mitigation measures.

Chapter 6 Recommendations and further work

Despite this thesis possessing several important strengths as mentioned in the previous chapter there are some weaknesses that should be addressed in further work. Among these weaknesses is the fact that especially the transport section would benefit from a deeper, more detailed analysis and simulations regarding topography, corresponding fuel consumption with and without cargo, traffic flow, winter and summer conditions, and alternative routes due to road works or accidents. The transport calculations in this thesis was included despite being rather basic as providing a preliminary overview of the potential of hydrogen production at Fosen was the goal. This would require more specific data which should be possible to obtain from a transport company. During the final stages of the study cost for trucks were finally discovered. According to the IEA a truck for compressed hydrogen come at cost of 8.6 million NOK, and a truck for liquefied hydrogen cost 6.5 million NOK [131]. Due to time limitations this was not possible to include in the overall cost but should be in further work.

An investment in a hydrogen production plant exhibits a few important characteristics. The CAPEX is a sunk cost, meaning that it cannot be recovered. It could, in theory, be possible to sell the production equipment, but this would not be easy as one of the strengths and reasons for the investment in the first place was TrønderEnergi's advantage in using their own electricity production. This means that an investment must have a secure and strong customer base. A hydrogen industry is not a short-term decision, there is only a long-term alternative. Furthermore, the production cost is determined by a fluctuating and uncertain electricity price. The profitability of such an investment is hence completely dependent upon the Norwegian electricity price staying low. However, the electrolysis technology is modular and allow the owners to choose both the start-up timing and the production rate. It is therefore paramount that a study locates the ideal location and timing of the production plant, the development in demand must be assessed, and the production rate must be set accordingly. Furthermore, it is vital to find a suitable harbor and storage facility and conclude where to locate the hydrogen storage hub, which centers all hydrogen production. It will be wise to keep the possibility of cross-border export in mind, despite such an arrangement being several years into the future. The hydrogen market is growing, e.g. France has a €100m hydrogen plan, and Germany has the biggest increase in hydrogen refueling stations in the world [132] [133]. In Denmark the CEF (Connecting Europe Facility) program announced support for 200 new buses, and in Sweden The Nordic Hydrogen Corridor is more than doubling the number of hydrogen stations, creating a hydrogen refueling network from Finland to Denmark [134] [135] [136] [137]. With a growing demand abroad, easily accessible export ports can be a vital capability to support a sufficiently large-scale production plant to keep costs down. That capability could also help make liquefaction plants profitable. As mentioned, the Norled ferry is planning on using liquefied hydrogen. As the demand for liquefied hydrogen will evolve slowly, it is important to be early with any liquefaction capacity. The slow increase in demand will probably not allow for several profitable liquefaction plants in Norway any time soon. To put in bluntly, the early bird gets all the worms. Being a supplier of liquefied hydrogen to the first customers in Norway may offer the market position required to in the longer run export liquefied hydrogen and exclude most national competitors. In other words, it is a market with significant first-mover advantages. A broad study of potential liquefied hydrogen demand should therefore be commenced as soon as possible in order to anticipate a market potential for liquefied hydrogen, and the location of an export capable port.

The delivery capacity of the electrolyser producers has not been investigated. This is an essential part of evaluating such an investment as large order will take time, and an order queue may already be in place. When deciding upon an electrolysis technology the delivery schedule should be a decisive factor. Though, the production capacity at Fosen will probably not start in a scale significantly challenging the delivery capacity of electrolyser producers. NEL announced in August 2018 the construction of the world's largest electrolyser plant. This will increase the production capacity to 360 MW/year. Located in Notodden, Norway, the plant will among other things help NEL deliver their contract for 448 electrolysers to Nikola [138].The plant will be fully operational by early 2020. However, in a growing market like the hydrogen market there is more opportunities for bottlenecks. A study of the electrolyser production capacity must therefore be a part of the aforementioned study to determine the timing of an investment.

In a wind powered hydrogen production system it is important to optimize the size of the production facility so that the utilization is maximized while still producing enough hydrogen. A larger production unit would be able to utilize more power and produce larger amounts of hydrogen but would be utilized in smaller periods of time. The exact operation time should be calculated to find the ideal production size. Electrolysis offer a big advantage in that it is a very modular technology easily expanded over time [52]. It is possible to calculate the optimal combination of electrolysers and the optimal production size based on both wind power potential and the customer base in the region. This would allow for a more detailed assessment which would support TrønderEnergi in any endeavor to develop a hydrogen production unit.

A further evaluation of which production technology to use would also be necessary. The fluctuation of wind power will be in favor of PEM, but it is difficult to say something specific as to what extent, and whether it makes up for the higher cost. A natural next step would therefore be to find data on the exact cost or degradation of restarts to compare PEM to alkaline technology. However, PEM is clearly most common when using wind power and would seem to be the natural choice. Being such a modular technology a PEM electrolyser investment may benefit from being distributed across several steps to allow for any near-term cost decrease to benefit the investors. As mentioned in chapter 2 the production rate is assumed to be constant throughout the lifetime of the equipment as well. There seems to be little available data on this, and it could therefore be necessary to research the degradation rate of all potential technologies. For larger production rates it could furthermore be profitable to connect to the grid despite increasing the electricity cost since the operation time increases (see Figure 25 and Figure 26). This could also affect the lifetime of the equipment and hence needs to be included in the study.

The control of an electrolyser system has its challenges too. Turning the system on and off is not instantaneous, wind conditions are fluctuating and the European power market trades within agreements made the previous day. In Norway, electricity is traded on the Nord Pool Spot Exchange. It split into a day-ahead market and an intraday market. In the day-ahead market one trades hourly contracts within an auction at noon (12.00) the previous day [70]. A larger electrolyser system would therefore need a sophisticated control system to avoid unnecessary and potentially damaging shutdowns. It is probably wise to combine forecasts with a buffer. If the wind power production is forecasted to fall below 5 percent above the rated power for instance, it is shut down. This will increase the amount of downtime, but also decrease the number of shutdowns. How this is solved will affect the lifetime of the different systems differently and is therefore an important part of developing a hydrogen production capability.

Besides the economic factors a hydrogen industry may give other advantages. It is feasible that the general public will find hydrogen fuel an exciting idea, thereby giving the provider a positive and environmentally friendly image. Such a development will give publicity and may improve the recognizability of a company. It would therefore be interesting to commence a study on the public perception of hydrogen. An environmental study of the advantages of locally produced hydrogen can then be used to improve hydrogen's status and outreach. Hydrogen is only as profitable as its customers determine it to be. Campaigns may be initiated to show those potential customers just how beneficial hydrogen may be to their operation.

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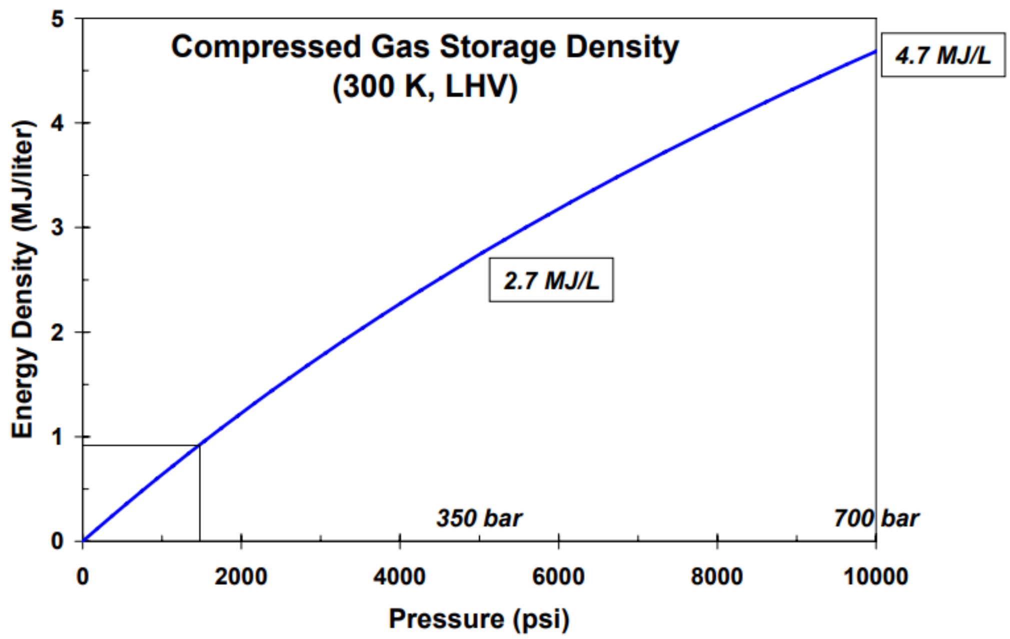
Appendix

A Projected electricity prices in the period 2020-2029

Year	Price [Euro/MWh]	Price [NOK/kWh]
2020	36.25	0.35
2021	33.43	0.33
2022	33.1	0.32
2023	33.0	0.32
2024	32.18	0.31
2025	32.25	0.31
2026	32.25	0.31
2027	32.25	0.31
2028	32.25	0.31
2029	32.25	0.31
Average	**32.921**	**0.32**

B Expected tank pressure

Calculation of the tank pressure is done by using the following graph:



Adapted from *[139]*, self-drawn cube in bottom left corner

100 bar equal 1450 psi. In the graph this reads to a little below 0.915 MJ/L. 1 m^3 equals 1000 L. That yields 915 MJ/m^3 at 100 bar. Hydrogen contains 131 MJ/kg. That yields 6.98 kg/m^3 at 100 bar.

C Power production at Bessakerfjellet

The average production for each month over the time period 2009-2016 expressed as a percentage of installed capacity.

	Jan	Feb	March	Apr	May	June	July	Aug	Sep	Oct	Nov	Dec
2009	0.533	0.264	0.468	0.249	0.215	0.133	0.141	0.196	0.499	0.305	0.515	0.403
2010	0.420	0.325	0.271	0.264	0.109	0.143	0.187	0.172	0.181	0.487	0.426	0.340
2011	0.506	0.538	0.521	0.343	0.200	0.203	0.101	0.147	0.318	0.473	0.399	0.498
2012	0.496	0.561	0.538	0.237	0.215	0.136	0.143	0.144	0.341	0.285	0.476	0.452
2013	0.276	0.383	0.316	0.291	0.215	0.139	0.289	0.189	0.206	0.314	0.488	0.597
2014	0.672	0.542	0.422	0.302	0.215	0.183	0.109	0.168	0.247	0.528	0.447	0.446
2015	0.629	0.554	0.383	0.389	0.215	0.225	0.115	0.264	0.338	0.379	0.336	0.538
2016	0.425	0.287	0.333	0.206	0.215	0.106	0.155	0.183	0.304	0.396	0.441	0.468

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
Average	0.494	0.432	0.407	0.285	0.200	0.158	0.155	.0183	0.304	0.396	0.441	0.468

D Feed water consumption

According to [68] the average feed water consumption is 0.9 L/Nm^3 H_2. 1Nm^3 H_2 equals 0.0899 kg H_2, which is to say 1 kg H_2 equals 11.126 Nm^3 H_2. Nm^3 is gas measured at a certain pressure and temperature. This was not expressed in NELs product list, so it is assumed that it is at 1 atmosphere and 0°C. 0.9 L/Nm^3 H_2 equals 10.013 L/kg.

The levelized cost of water is calculated by using a discounting factor of 8%.

In addition, a water gauge must be installed to measure the amount of water. That is not municipality specific. This is done by a plumber and the cost is usually around 3000 NOK, so it is negligible. The gauge remains the municipality's property however, with an annual fixed cost of 266 NOK [140]. Total cost of the water gauge for the scope of this thesis is 3000+266*15 = 6990.

The levelized OPEX for each year with summed total cost (CAPEX included) at the bottom row:

	Electrolyser A	Electrolyser B	Electrolyser C
0	15 963	24 436	15 132
1	14 780	22 626	14 011
2	13 685	20 950	12 973
3	12 672	19 398	12 012
4	11 733	17 962	11 123
5	10 864	16 631	10 299
6	10 059	15 399	9 536

7	9 314	14 258	8 830
8	8 624	13 202	8 175
9	7 985	12 224	7 570
10	7 394	11 319	7 009
11	6 846	10 480	6 490
12	6 339	9 704	6 009
13	5 869	8 985	5 564
14	5 435	8 320	5 152
15	5 032	7 703	4 770
Sum[44]	**174 284**	**255 289**	**166 346**

	Water consumption per kg H_2 produced [kg H_2O/kg H_2]	Varying water expenses per kg H_2 [NOK/kg H_2][45]	Amount of H_2 produced over lifetime [kg H_2]	Water cost over lifetime [MNOK]
Electrolyser A	10	0.145	4383000	0.343
Electrolyser B	10	0.145	13149000	0.424
Electrolyser C	20[46]	0.29	3523932	0.335

E Weight- and volume percentage, wt% and v%

Pressure [bar]	kg hydrogen	total weight	wt%	volume [l]	v%	Source
60	4.2	215	2.0	850	0.5	Mahytec
525	9.7	260	3.7	300	3.2	Mahytec
700	2	53.6	3.7	52	3.8	Mahytec
200	0.7	16	4.4	46	1.5	Hexagon
250	8	164	4.9	450	1.8	Hexagon
250	6	94	6.4	350	1.7	Hexagon
300	7.2	112	6.4	350	2.1	Hexagon
350	7.5	101	7.4	312	2.4	Hexagon
350	8.4	112	7.5	350	2.4	Hexagon
500	16.5	280	5.9	530	3.1	Hexagon
500	10.7	229	4.7	347	3.1	Hexagon
700	1.4	34	4.1	36	3.9	Hexagon
700	1.6	29	5.5	39	4.1	Hexagon
700	2.6	43	6.0	64	4.1	Hexagon
700	3.1	59	5.3	76	4.1	Hexagon
950	12.4	365	3.4	254	4.9	Hexagon

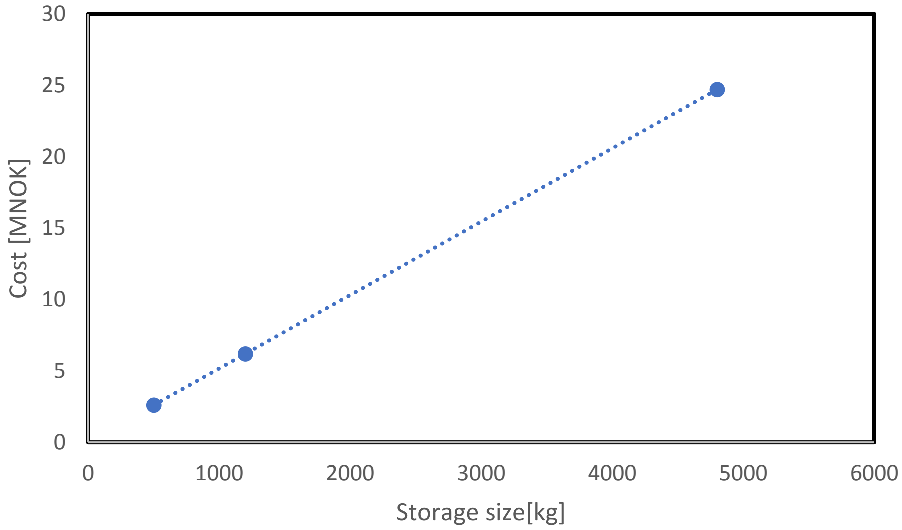
[44] Including varying cost and one-time fees in accordance with equation (4)

[45] 1 M^3 of water weighs 1000 kg.

[46] Disclosed in communication with market actor

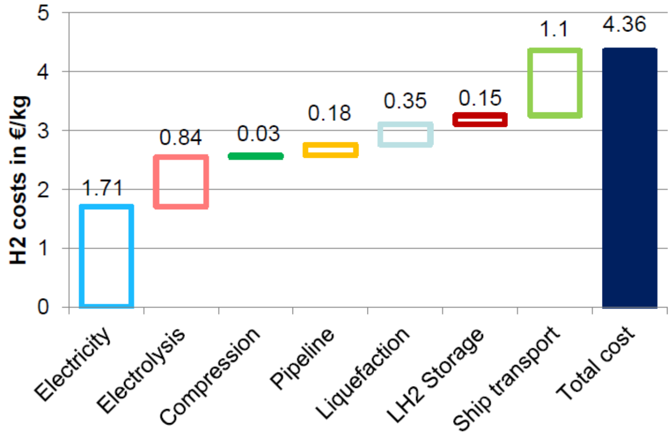
F Storage tank cost expressed graphically

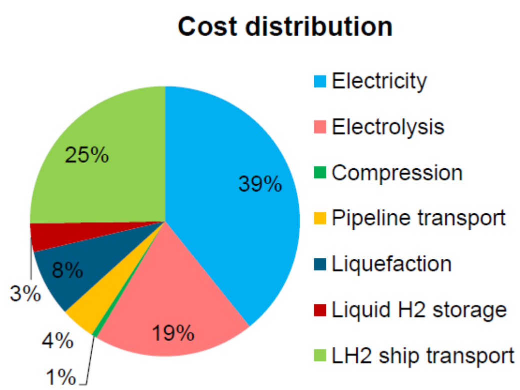
This is the result of plotting the cost data in a graph. It is almost perfectly linear.



G Liquefaction costs

In addition to the data expressed in the text research found data for a very large project. At the World Hydrogen Energy Conference in Rio 2018, Dr. Detlef Stolten et al., Director of the Institute of Energy and Climate Research at Forschungszentrum Jülich, presented a calculation over costs related to hydrogen production in Argentina and transport to Japan [92]. That yielded the cost overview seen in the graph below.





It says that liquefaction will constitute about 11% of total costs, and this is included transport to Japan (21 400 km). This is a cost of 0,5 €/kg, or 4,9 NOK/kg (Liquefaction plus LH2 Storage). Its basis for transport is Kawasaki's LH2 cargo ships which is in the R&D state and is expected to be launched sometime in the second half of the 2020s. These calculations were for enormous production quantities and included several very positive assumptions. It is not included in the data set because it will result in a negative regression line for sufficiently large production rates. However, it is mentioned here as a point of reference.

The entire data set is as follows:

Source	Produksjons-rate [tpd]	Totalkostnad (OPEX + CAPEX) [NOK]
Supplied information	1.5	38.93
Conventional [104]	5	19.61
West 2003 [103]	5	10.00
Supplied information	30	9.73
Linde 2010 I [104]	50	13.70
IDEALHY 2013 I [104]	50	13.33
LINDE 2010 II [104]	50	7.84
IDEALHY 2013 II [104]	50	9.80
New Target I [104]	150	12.00
New Target II [104]	150	6.47
Presentation [92]	5205	4.90

This results in the graph with the best fitted line and the function is

$$y = -4.619\ln(x) + 29.079$$

Other interesting information that was found was the presentation by Joe Schwartz for Praxair in 2011 [141]. That states the following

	2005 (status)		2012		2017	
Production rate	30 tpd	300 tpd	30 tpd	300 tpd	30 tpd	300 tpd
Installed Capital Cost [million $]	50	170	40	130	30	100

However, as this data doesn't contain information about the expected lifetime of the plant it is not possible to calculate a cost per kg of liquefied hydrogen. It is therefore not directly comparable to the other sources used for calculating a liquefaction cost. But as information about cost of liquefaction is so difficult to find, it is included here to provide further points of comparison if needed.

H Transport

The following data has been supplied during this study:

From	To	Km	Time [min]	One container	Two containers
Lundamo	Brattøra	43	50	3000	3800
Driva	Brattøra	129	115	7500	11500
Nea	Brattøra	77	81	5146	7472
Trolla	Brattøra	8.7	15	1500	1900
Uthaug	Brekstad	6.4	9	1400	1800

To allow for comparison with the Fosen wind farms a price per km of travel was calculated

From	To	One container [NOK/km]	Two containers [NOK/km]
Lundamo	Brattøra	69.8	88.4
Driva	Brattøra	58.1	89.1
Nea	Brattøra	66.8	97.0
Trolla	Brattøra	172.4	218.4
Uthaug	Brekstad	218.8	281.3

I Comparison of electricity price

Projected electricity prices for other countries has also been obtained:

	Denmark [NOK]	France [NOK]	Germany [NOK]
2020	0.42	0.52	0.49
2021	0.39	0.48	0.47
2022	0.38	0.47	0.47
2023			0.48
2024			0.48
Average	**0.39**	**0.49**	**0.47**

J Electricity consumption in hibernation

The electricity consumption during electrolysers’ hibernation mode is as following assuming the indicative numbers mentioned:

	Electricity consumption in hibernation mode [kW]
Electrolyser A	6.2
Electrolyser B	18.7
Electrolyser C	5

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