Simen Kjørstad
Morten Elias Lødemel
Mikael Melstveit Matthews

Integration of a Hydrogen Solution for Solving Power-Related Grid Problems

Analysing the Competitivness of Hydrogen

Bachelor's thesis in Renewable Energy (Fornybar Energi)
Supervisor: Steven Boles (NTNU) and Zohreh Jalili (NTE)
May 2022

Bachelor's thesis

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

Kunnskap for en bedre verden

Simen Kjørstad
Morten Elias Lødemel
Mikael Melstveit Matthews

Integration of a Hydrogen Solution for Solving Power-Related Grid Problems

Analysing the Competitivness of Hydrogen

Bachelor's thesis in Renewable Energy (Fornybar Energi)
Supervisor: Steven Boles (NTNU) and Zohreh Jalili (NTE)
May 2022

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

NTNU
Kunnskap for en bedre verden

Norwegian University of Science and Technology

Bachelor thesis

Project title: Integration of a Hydrogen Solution for Solving Power-Related Grid Problems **Oppgavens tittel (NOR):** Integrering av en Hydrogenløsning for å Løse Effektproblemer i Strømnettet	**Date handed out:** 29.11.2021 **Submisson date:** 20.05.2022 **Number of pages / pages in appendix:** 146/6
Group participants: Simen Kjørstad Morten Elias Lødemel Mikael Melstveit Matthews	**Supervisor:** Steven Boles **Project number:** 22BIFOREN-011
Client: NTE	**Client Supervisor:** Zohreh Jalili

Available: ☒

Available after agreement with NTE: ☐

Report made available after:

Preface

This bachelor thesis marks the end of the Bachelor's Degree Programme in Renewable Energy at the Norwegian University of Science and Technology (NTNU) in Trondheim. The project is provided by NTE. The main focus of the thesis is to evaluate the competitiveness of a hydrogen grid solution compared to an upgrade of grid infrastructure. The thesis corresponds to 20 credits, and has to be delimited accordingly. The thesis is written in cooperation between the following students: Simen Kjørstad, Morten Elias Lødemel and Mikael Melstveit Matthews.

Several experts on the field of hydrogen and the electrical grid have been contacted throughout this period. We would like to express our gratitude to all the contributors of this thesis. Many thanks to Daniel Janzen for help with the economic analysis. A special thanks to Rune Paulsen for guidance on the electrical grid and suggestions to calculations. This thesis would not have the same depth and insight without their help.

We would also like to thank Zohreh Jalili and NTE for providing us with this project, and for weekly guidance and follow-up. These meetings have been valuable for collecting information and sort out ideas. In addition, Zohreh has arranged meetings with manufacturers, which have been very helpful. Furthermore, we would like to thank our internal supervisor, Steven Boles, for support during the process of writing this thesis.

Trondheim, May 20, 2022

Simen Kjørstad	Morten Elias Lødemel	Mikael Melstveit Matthews

Sammendrag

Elektrifisering og økende andel av fornybar energi har tydeliggjort behovet for nye energibærere. Dagens strømnett er designet for et økende behov på noen få prosent årlig. Dagens behov øker mye raskere enn dette. Den raske økningen i elektrisistetsbehov øker presset på strømnettet. Utbygging av strømnettet er dyrt og tidkrevende. Alternative løsninger må vurderes for å muliggjøre overgangen fra et fossilbasert til et miljøvennlig energisystem.

I dag er det et begrenset antall løsninger som tilbyr langsiktig lagring av energi. Hydrogen er en mulig løsning på dette problemet. Med hydrogen kan man lagre store mengder energi over lange perioder, som kan utnyttes ved behov. Denne energien kan bidra til å stabilisere strømnettet, samt utsette eller unngå behovet for dyre oppgraderinger. Varierende energiforsyning og energibehov gjør det utfordrende å dimensjonere fremtidige oppgraderinger av strømnettet. Resultatet kan være at nettet dimensjoneres for situasjoner som sjelden forekommer. Dette kan gi høye og tildels undøvendige utgifter. Basert på dette er det aktuelt å se på om alternative løsninger kan utsette eller fjerne behovet for slike dyre oppgraderinger av strømnettet.

Oppgaven dreier seg i hovedsak om hvorvidt en hydrogenbasert løsning er konkurransedyktig i forhold til oppgraderinger av strømnettet. Hovedmålet med oppgaven er å presentere en sammenligning av disse to løsningene. Dette gjøres ved hjelp av en økonomisk analyse. Den økonomiske analysen brukes som grunnlag for å vurdere konkurransedyktigheten til en hydrogenløsning. Denne består av å beregne hydrogenkostnad over levetiden, LCOH, og energiproduksjon over levetiden, LCOE.

Beregningene viser at et elektrolyseanlegg i Meråker på 1.25 MW, kan produsere hydrogen til en LCOH-pris på 47.5 NOK/kg etter kompresjon. Dersom man legger til lagring og transport blir LCOH-prisen betydelig høyere. Dette gir en LCOH-pris på 71.0 NOK/kg. Denne prisen illustrerer hvor viktig transport er for den totale prisen. I denne oppgaven ser man på muligheten for å bruke hydrogenet i Sørli, rundt 300 km fra Meråker. Den store transportkostnaden illustrerer at fremtidige småskalaprosjekter bør være i nærheten av produksjonssted.

Det er gjort antagelser som forenkler kalkulasjonene. Videre arbeid bør ta for seg disse antagelsene i mer detalj. Hydrogenmarkedet er i stadig utvikling. Fremtidig teknologi- og markedsutvikling kan endre premissene som ligger til grunn for denne oppgaven.

Resultatene fra oppgaven viser at en hydrogen løsning kan gi samme pris som alternative løsninger for oppgraderinger av nettet. Prisen på elektrisiteten som anlegget produserer er 6.25 NOK/kWh. Dette gir en totalpris for hydrogenløsningen på 210 MNOK. Til sammenligning er prisen på de ulike nettoppgraderingsløsningene mellom 144 og 226 MNOK. Sentrale aktører regner med at prisen på hydrogen vil kunne leveres til lavere priser enn det som fremkommer her. På sikt vil dette kunne gi mer konkurransedyktige hydrogenløsninger.

Abstract

Electrification and the growing share of renewable energy have highlighted the need for new energy carriers. Today's electrical grid is designed for an increasing demand of a few percent annually. The current demand increases much faster. The rapid increase in electricity demand increases the pressure on the electrical grid. Development of the electrical grid is expensive and time-consuming. Alternative solutions must be considered to enable the transition from a fossil-based to an environmentally friendly energy system.

Today, there are a limited number of solutions that offer long-term storage of energy. Hydrogen is a possible solution to this problem. Hydrogen can store large quantities of energy over long periods. This energy can be utilised when needed. Consequently, hydrogen can contribute to stabilise the electrical grid, and delay or prevent the need for expensive grid upgrades. Varying energy supply and energy demand make it challenging to dimension future grid upgrades. The result may be that the grid is dimensioned for situations that rarely occur. This can result in high and sometimes unnecessary expenses. Based on this, it is relevant to look at whether alternative solutions can delay or eliminate the need for such expensive electrical grid upgrades or not.

The thesis investigates whether a hydrogen-based solution is competitive compared to upgrading the electrical grid. The main objective of the thesis is to present a comparison of these two solutions. The result is based on an economic analysis. This is used as a basis for assessing the competitiveness of a hydrogen solution. The economic analysis consists of calculating hydrogen cost over lifetime, LCOH, and energy production over lifetime, LCOE.

The calculations show that an electrolysis plant in Meråker of 1.25 MW, can produce hydrogen at an LCOH price of 47.5 NOK/kg after compression. With additional storage and transport, the LCOH price is significantly higher. This gives an LCOH price of 71.0 NOK/kg. This price illustrates how important transport is for the total price. This study evaluates the possibility of using the produced hydrogen in Sørli, around 300 km from Meråker. The large transport cost illustrates that future small-scale projects should be in close distance to the production site.

Assumptions have been made that simplify the calculations. Further work should address these assumptions in more detail. The hydrogen market is constantly changing. Future technology and market development may change the premises on which this thesis is based.

The results from the thesis show that a hydrogen solution can give the same price as alternative solutions for upgrades of the grid. The price of electricity produced from the fuel cell is 6.25 NOK/kWh. This gives a total price for the hydrogen solution of 210 MNOK. In comparison, the prices of the various grid upgrade solutions are between 144 and 226 MNOK. Market participants expect that the price of hydrogen can be delivered at significantly lower prices than what is presented in this study. In the long-term, this could provide even more competitive hydrogen solutions.

Table of contents

List of Figures

List of Tables

List of Terms

Term	Explanation
Anode	The electrode where the oxidation occurs.
Boil-off	A phenomenon which happens when liquid hydrogen is not cold enough, so that parts of the liquid evaporates.
Cathode	The electrode where the reduction reaction occurs.
Discount Rate	A rate used to determine the present value of future cash flows.
Electrical Grid	A network for electricity delivery between consumers and producers.
Electrode	Electrical conductor.
Electrolyte	Ionic conductor.
Electrolysis	A process that uses electricity to split the water molecule to hydrogen and oxygen.
Electrolyser	A machine where electrolysis occur.
Embrittlement	Degradation of metals due to contact with hydrogen.
Endothermic	A reaction that absorbs energy.
Enthalpy	A thermodynamic property that describes a system's internal heat.
Entropy	A thermodynamic property that describes the unavailability of a system's thermal energy.
Exothermic	A reaction that releases energy.
Fuel Cell	A machine that uses hydrogen and oxygen to produce electricity and water.
Grid Tariff	Costs for using the electrical grid for transporting electricity.
Net Present Value	The difference in the present value of cash inflows and cash outflows over a period of time.
Rectifier	A machine that converts AC to DC.
Specific energy	Energy stored per unit mass or per unit volume.
Transformer	A device that transfers electric energy from one circuit to one or multiple others.

List of Symbols

Symbol	Unit	Explanation
α *		Charge Transfer Coefficient
η_f	$[\%]$	Efficiency
ρ	$[S/cm]$	Ionic Conductivity
ΔG	$[J]$	Change in Gibbs Free Energy
ΔH	$[J]$	Change in Enthalpy
ΔS	$[J/K]$	Change in Entropy
ASR_Ω	$[\Omega cm^2]$	Area Specific Resistance
c*		Coefficient
e_H	$[kWh]$	Electricity Produced from Hydrogen
E_{anode}	$[V]$	Anode Half Cell Potetial
$E_{cathode}$	$[V]$	Anode Half Cell Potetial
E_{cell}	$[V]$	Cell Voltage
E_{ref}	$[V]$	Reversible Voltage
F	$[C/mol]$	Faraday's Constant
j	$[A/m^2]$	Electrode Current Density
j_0	$[A/m^2]$	Exchange Current Density
j_L	$[A/m^2]$	Limiting current density
L	$[m]$	Length
m_H	$[kg]$	Mass of Hydrogen
n	$[year]$	Economical Lifetime
r	$[\%]$	Discount Rate
R	$[J/Kmol]$	Universal Gas Constant
T	$[°C]$	Temperature
U_{TH}	$[V]$	Thermo Neutral Voltage
z*		Number of electrons

* Blank fields means that the symbol is dimensionless.

List of Acronyms

Acronym	Explanation
AC	Alternating Current
AEC	Alkaline Electrolysis Cell
AEMEC	Anion Exchange Membrane Electrolysis Cell
AFC	Alkaline Fuel Cell
ASR	Area-Specific Resistance
CAPEX	Capital Expenditures
CCS	Carbon Capture and Storage
CHP	Combined Heat and Power
DC	Direct Current
DMFC	Direct Methanol Fuel Cell
DSB	The Norwegian Directorate for Civil Protection
DSO	Distribution System Operators
GDL	Gas Diffusion Layer
Genset	Generator Set
HHV	Higher Heating Value
IRENA	International Renewable Energy Agency
LCOE	Levelised Cost of Electricity
LCOH	Levelised Cost of Hydrogen
LCOTH	Levelised Cost of Transporting Hydrogen
LHV	Lower Heating Value
LOHC	Liquid Organic Hydrogen Carrier
MCFC	Molten Carbonate Fuel Cell
MNOK	Million Norwegian Krone
MV	Medium Voltage
NOK	Norwegian Krone
NVE	The Norwegian Water Resources and Energy Directorate
OPEX	Operational expenditures
PAFC	Phosforic Acid Fuel Cell
PEMEC	Polymer Electrolyte Membrane Electrolysis Cell
PEMFC	Polymer Electrolyte Membrane Fuel Cell
SOEC	Solid Oxide Electrolisis Cell
SOFC	Solid Oxide Fuel Cell
TSO	Transmission System Operator
VAT	Value Added Tax

1 Introduction

The demand for clean electricity and energy storage solutions increases globally in light of the Paris Agreement. Countries have agreed to set high ambitions to limit global warming. The energy system needs to change, from producer to consumer, for these ambitions to be reached. This energy transition is widely understood, and countries have set frameworks for how they will reach their targets. This includes a transition from fossil fuels to renewable energy sources. Higher shares of renewable energy and electrification of sectors result in higher electricity demands and increasing pressure on the electrical grid. This results in challenges and implications that have to be solved for environmental targets to be met.

The transition to a fossil-free energy system is a transition towards an energy system with variable supply and demand. This change will be radical. As of 2020, fossil fuels accounted for more than 80% of the global primary energy consumption. Renewable energy sources accounted for no more than 13% of the total primary energy consumption. Towards 2030 and 2050, the share of renewables is expected to increase significantly. By 2050, renewable energy sources are expected to make up two-thirds of the total energy consumption and 85% of power generation. This transition will be important to limit global warming. However, new energy carriers will be needed to fully exploit the increased share of renewable energy and transfer energy to where the demand takes place. In addition, energy carriers can help maintain the quality of the power provided to end-users. [1, 2]

Limited grid capacity, in combination with intermittent energy supply, creates a demand for low-carbon seasonal storage solutions. Currently, there are limited options for long-term storage of energy. Hydrogen is a promising candidate for meeting this increasing demand for storage solutions. Hydrogen can better exploit renewable energy by providing large storage capacities and seasonal storage. The stored energy can be consumed in periods of need using a fuel cell, generating electricity for off- and on-grid facilities. Furthermore, this can provide stability to the electrical grid. Some sectors are challenging to electrify, both technologically and economically. Hydrogen offers a viable solution to decarbonise these sectors, where emissions are difficult to reduce. In other words, hydrogen can play a critical role in a clean energy system. [3]

Investments in hydrogen are increasing rapidly. This is a response to the global commitment of decarbonisation. At the beginning of 2021, more than 30 countries, including the EU, have released hydrogen roadmaps. In addition, several hundred hydrogen projects have been announced. Furthermore, billions of dollars from public funding are committed to developing hydrogen technology and solutions. However, despite the recent uptake and political roadmaps for hydrogen, several barriers have to be overcome. Regulatory frameworks are currently a limitation for further investments and deployment of hydrogen solutions. Further investments are also needed to improve the cost competitiveness of hydrogen applications. [4]

1.1 Scope of the Thesis

This thesis aims to investigate the competitiveness of a fuel cell system operation to solve grid problems compared to upgrading the grid infrastructure. The fuel cell system will be fuelled with green hydrogen from an electrolysis plant at Meråker. The produced hydrogen will be compressed, stored, and transported to the area of fuel cell operation. In order to estimate the total costs of the fuel cell system alternative, there will be conducted a levelised cost of hydrogen (LCOH) and a levelised cost of electricity (LCOE). The LCOH calculations will take into account all the costs of installment, operation, and distribution of hydrogen. The LCOE will consider the fuel cell system installment and operation costs and the hydrogen bought to the price estimated from the LCOH. The total cost of the facility will then be estimated based on the LCOE and the total amount of produced electricity through the lifetime of operation. Finally, the total cost will be compared to what a required investment in grid infrastructure would cost.

To achieve the purpose of this study, based on the information presented so far, the following thesis statement will have to be answered:

Is the integration of a hydrogen solution for solving power-related grid problems competitive compared to an upgrade of grid infrastructure?

Defining competitive, both technical and economical aspects have to be evaluated. The thesis focuses on the entire hydrogen value chain, from production through electrolysis, to generation of electricity from a fuel cell.

1.1.1 Delimitations

The value-chain of hydrogen includes several components. Each component have to be included in order to present a credible economical analysis. For simplicity, assumptions were made to make the study manageable. Alternative technologies for the different components in the value-chain is presented. However, few of these are considered as an actual alternative for this study. This applies to, among others, the choice of electrolyser and fuel cell. For both cases, PEM-technology is considered the only option.

Furthermore, the calculations are affected by the fact that several parameters are assumed to be constant. This applies to, among others, the efficiency of components, electricity price and the price of hydrogen. While these parameters might vary significantly for a real case, this is not accounted for in this thesis. Consequently, the operational profiles of the different components such as the electrolyser and the fuel cell system are not evaluated in greater detail. The outputs of interest are the production volume from the electrolyser and generated electricity from the fuel cell.

These delimitations will affect the calculations, which introduce a level of uncertainty to the results. However, it is assumed that this does not affect the conclusion of this thesis.

1.1.2 Thesis Structure

The thesis is divided into different chapters. Chapter 2 provides information on the electrical grid and how future energy demands might change. The need for energy security is also highlighted. Chapter 3 presents theory about hydrogen and the hydrogen market in general, production and storage. Chapter 4 provide information on fuel cells and different applications where fuel cells can be used. Chapter 5 presents an overview of the economic assessments conducted in this thesis. These four chapters provide the theoretical basis necessary for further analyses. The methodology for collecting data, perform calculations and defining the system is presented in chapter 6. Results are presented in chapter 7. These results are further discussed in chapter 8, with a final conclusion at the end of the thesis.

1.2 Contributors

Information from several contributors have been important for the result of this thesis. NTE, with Zohreh Jalili, has been the main contributor. NTE is also the client of this case. Other important contributors is presented in table 1. Information has been gathered via physical and digital meetings, and mail.

Table 1: Contributors to the Bachelor thesis

Names	Company	Title
Geir Martin Bakken	NTE	Business Developer, Renewable Energy, at NTE [5]
Jørn Helge Dahl	Hexagon Purus	Director of Sales and Marketing in Hexagon Purus [6]
Knut Granlund	Enova	Senior adviser in Enova [7]
Thomas Holm	IFE	Research scientist in hydrogen at Institute for Energy Technology [8]
Daniel Janzen	Greensight/Norsea	Energy Economist & Business Developer [9]
Fredrik Moen	Meråker Hydrogen	CEO in Meråker Hydrogen [10]
Odd Moen	Siemens	Head of Strategy and Business Development in Siemens [11]
Steffen Møller-Holst	SINTEF	Vice President Marketing, Hydrogen Technologies, in SINTEF [12]
Rune Paulsen	Tensio	Leader of network development and network strategy in Tensio [13]
Bjørn Simonsen	Saga Pure	CEO in the investment company Saga Pure [14]
Ronnie Smedsvik	Andersen & Mørck	Freight Forwarder in Andersen & Mørck [15]

2 Status of the Grid

The electrical grid is a critical infrastructure in the modern society. Almost all parts of society depend on a reliable supply of electricity. The grid is designed to deliver peak demands, as well as handle small increases in demand each year. The rapid growth in demand and renewable generation cause problems in the existing electricity grid. Problems grids operators face are, among others, driven by the electrification and decarbonisation of sectors. In several regions, the existing grid has problems meeting growing new demands, while still operating within regulatory limits. This calls for expensive grid upgrades or new measures to meet the requirements of a changing energy system.

2.1 Electrical Grid

The electrical grid is the link between the producers and the consumers of electricity. The electrical grid also connects the Norwegian power system with the power systems abroad. The Norwegian power system is complex and needs to ensure a secure and reliable supply of electricity. Industries, businesses, households, and essential public services depend on a well-functioning power system with a reliable electricity supply. The electrical grid is a critical infrastructure in a well-functioning power system. Hence, it has a core function in modern society. [16]

The electrical grid must deliver electricity from remote power plants to the areas where the consumption occurs. As a result, electricity often travels long distances between these two points. Furthermore, electricity is a highly perishable product, as it must be utilised the exact second it is produced. This requires a balance between production and consumption at all times. The grid is designed to handle power demands at all times. Electrification and increased use of intermittent renewable power pose challenges for the grid and the grid operators. These challenges will keep rising in the future. Hence, good planing, maintenance, upgrade of the current system, and new solutions are required to solve the challenges of the future power system. [17]

2.1.1 Grid Infrastructure

As mentioned above, the grid infrastructure delivers electricity from power plants to consumers. The Norwegian electricity grid consists of three levels: the transmission grid, the regional grid, and the distribution grid. Most consumers of electricity are connected to the regional or the distribution grid. The different levels are presented in figure 1.

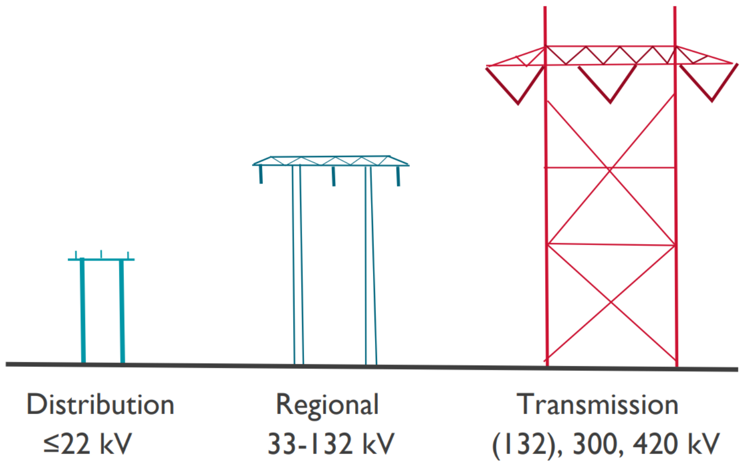

Figure 1: Different levels of the Norwegian electricity grid. [18]

As shown in figure 1, the transmission lines operate at the highest voltages. The voltage is usually 420 or 300 kV, but there are some lines carrying 132 kV. The regional grid links the transmission grid and the distribution grid. The regional grid may also include production and consumption from large electricity producers and major consumers. Power-intensive manufacturing or the petroleum industry are generally connected to the transmission or regional grid. Normal voltage levels in the regional grid are 132 and 66 kV, but they can be operated at levels down to 33 kV. The lowest level is the distribution grid. This is the part of the grid that normally supplies power to consumers. The distribution grid carries voltages from 22 kV down to 230 V. The low voltage distributed to customers usually is 400 V and 230 V in Norway. [16, 18]

Transformers are used in the electrical grid to convert voltage between different levels. An example is between the transmission grid and the regional grid. The voltage is stepped down from the transmission grid to the regional grid [19]. Before entering consumers, higher voltages need to be stepped down to safe levels. On the other hand, step-up transformers are used at power stations to reach the high voltage levels needed to transmit electricity. Power losses in transmission lines are proportional to the current in the lines. As a result, reducing the current flow will reduce the power loss in the transmission lines. The current can be reduced by increasing the voltage. Hence, high voltages are used to reduce losses and increase power transmission efficiency. [20]

2.1.2 Organisation of the Electrical Grid

Costs of grid development are high. Hence it is not rational to construct several competing grids that are not fully used. As a result, grid operations are not subject to competition. For this reason, there is just one distribution system operator (DSO) in each distribution area. The DSO has the monopoly for grid operations in their area. Approximately 130 DSOs operate the Norwegian regional and distribution grid. Statnett have the monopoly of the transmission grid operation in Norway and is the only Norwegian transmission system operator (TSO). [16, 18]

Statnett have the overall management and control of the Norwegian power system. They have the task of coordinating production and electricity consumption to always ensure balance in the power system. Statnett own the Norwegian transmission system and the interconnectors that connect the Norwegian power system to the European power system. Statnett's most essential tasks are planning, expanding, and investing in the power grid to meet future needs. Every other year Statnett update their Grid Development Plan and Power System Plan. The Power System Plan describes the current power system and outlines possible developments in transmission needs and potential actions. The Grid Development Plan describes what drives the development of the power system, ongoing development projects, and planned activities. [17, 21]

Statnett collaborate with local DSOs. When a company or a producer wants to connect to the grid, they contact the local grid operator. The DSO needs to evaluate whether the grid has sufficient capacity or if measures are needed. In all cases where the transmission system is affected, the connection must be clarified with Statnett. Statnett have processed applications for close to 11 000 MW increased volume for the last two years. These applications are primarily from local grid companies. This is because most connections occur directly in the local or regional grid. [22, 23]

Regluation of the Grid

The DSOs are heavily regulated because of their local monopoly. The purpose of this is to ensure the necessary level of investment in the grid, satisfactory maintenance and operation, as well as to prevent the DSOs from exploiting their monopoly. There are also several other purposes of regulation. This includes ensuring that everyone who requires it has access to the grid, that the quality of supply is satisfactory, that there is sufficient capacity on the grid, and that the security of supply is maintained. [24]

The Norwegian water resources and energy directorate (NVE) regulates the power system and grants licenses for transmission and production of energy. Facilities for production, conversion, transmission, and distribution of electrical energy cannot be built, owned, or operated without a license from NVE. Within an area, a permit can be granted to construct, own, and operate facilities to distribute electrical energy between voltage levels determined by Norwegian authorities. The permits are given with specific obligations and requirements for the grid companies listed in the previous paragraph. The permits allow the grid companies to build and operate with voltages up to 22 kV without submitting every single case to NVE. [18, 25, 26]

The construction and operation of facilities not covered by the assigned licensing scheme need new permits. NVE processes applications for such permits. In these cases, NVE thoroughly processes the information given in the case. This process is comprehensive and time-consuming. How the case is processed depends on the size of the planned facility and the assumed consequences for the surroundings. [27]

DSOs are also subject to legal and functional unbundling. This is also a part of the NVE regulations. New regulations regarding legal and functional unbundling came into force on the 1st of January and the 12th of March 2021. The background for these new regulations is to separate monopoly activities from activities exposed to competition. Legal unbundling requires that grid operations, being monopoly activities, are carried out by companies whose only purpose is the grid operation. Production and trading, which are competitive activities, need to be carried out by separate companies. Consequently, a grid company cannot be owned or own an entity that is involved in production or trading. Functional unbundling, on the other hand, requires that the grid company is operated independently of other activities. Tensio, a grid company in Trøndelag, is a result of these new regulations. The company is a fusion of the grid operating parts of the energy companies NTE and TrønderEnergi. [16, 28, 29]

Incomes and Expenses in the Power System

As described above, Norwegian authorities have established extensive control of monopoly operations. This is to prevent the grid companies from exploiting their monopoly position. NVE have a revenue cap regulation in which each grid company has an annual revenue cap. The annual revenue cap is set at a level where the grid companies can earn revenues that cover the costs of operation and maintenance and give a reasonable return on invested capital. However, this requires efficient grid operation, utilisation, and development. If the grid is operated with low efficiency, or in the case of power supply interruptions in the grid, the permitted revenue of the grid companies is reduced. These regulations will secure the customers from being exploited, while still securing revenues for grid companies. [24]

The grid companies earn most of their incomes from grid tariffs. The tariffs are set so the incomes do not exceed the permitted level set by the regulations mentioned above. The customers of the grid companies pay a tariff to get access to the power market. Grid companies are required to offer all customers a connection to the grid. These connections result in a cost. If the connection of a customer requires grid investments, the grid company may require a connection charge, and the customer must cover a proportional share of the costs entailed. The object of this cost is to make the customer responsible for the connection and the eventual grid infrastructure upgrade. The costs not directly related to the responsible customer will result in increased tariffs for the other customers of the grid company. [24, 30, 31]

In addition to grid tariffs, customers of the power market also need to pay for their electricity. The grid tariffs illustrate that the grid customers pay the local grid company to transport electricity to them. The electricity price is based on the price on the power market Nord Pool. Nord Pool is the leading power market for the purchase and sale of electricity in Nordic and Baltic countries, as well as Germany and Great Britain. Nord Pool calculates the system price for the following day. The system price is calculated theoretically, assuming there are no bottlenecks in the Nordic transmission lines. This price is the same for the entire Nordic market and works as a reference for further pricing. In addition to this, Nord Pool calculates area prices. These prices take the bottlenecks in the grid into account. The area prices create the balance between purchase and sales bids from participants in the different bidding zones in the Nordic market. Norway has five such zones. These are displayed in figure 2. The red arrows illustrate the power exchange between the regions and other countries. The area prices depend on numerous variables. Local variables can be reservoir filling, power outages, and bottlenecks on the grid. Since Norway is connected to other countries, supply and demand from all countries using the marketplace is the most decisive variable.[32–34]

The power suppliers buy the electricity from Nord Pool and sell it to their customers, providing a balance between production and consumption [34]. The electricity demand varies from season to season and over a day. As a result, the electricity price fluctuates throughout the day. The price of electricity varies hour by hour and is highest in the periods with the highest demand. This is usually in the morning at 07-10 and in the afternoon and evening at 17-20. The lowest electricity prices are usually between 02-05 at night. [33]

2.1.3 Bottlenecks in the Grid

Everyone connected to the grid will to some extent, influence the quality of the supplied electricity. When the demand for electricity and power is too high, bottlenecks can occur. Regarding the grid, the term bottleneck is used when there is a higher demand for power transfer than what the grid can withstand. Bottlenecks cause problems for the quality of the electricity supply. It can either include problems with continuity of supply or voltage quality. Further, this can result in problems with delivering the required levels of voltage that are expected. For this reason, requirements to ensure delivery are strictly regulated by laws. The laws ensure that the delivered voltage has a certain quality in order to be safely used and not damage electrical applications. Low voltage quality can cause a breakdown of electric equipment, shorten the lifetime of devices, and flickering in lighting. [35, 36]

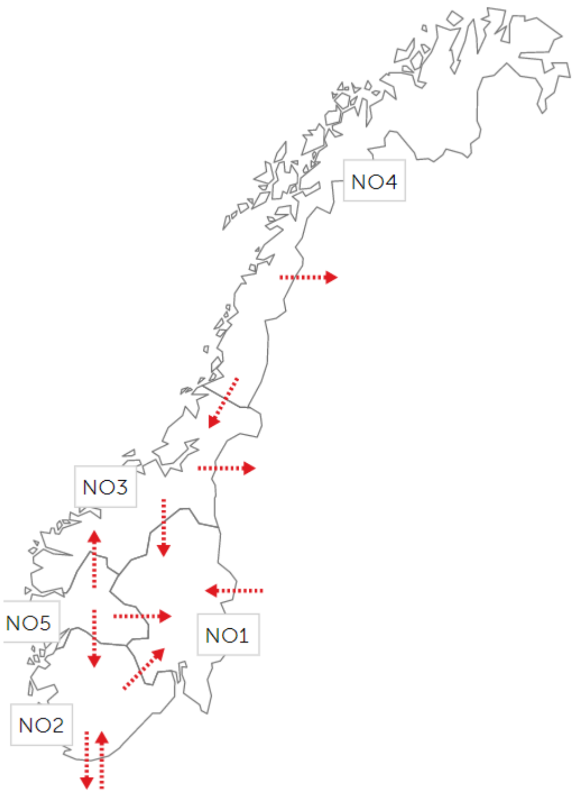

Figure 2: Norway is divided into five different power regions, with different power prices. The red arrows represent normal power exchange patterns. [32]

Voltage quality parameters have been defined in electricity supply regulations that describe frequency, continuous voltage phenomena, and random voltage phenomena. For example, typical limit values for voltage and power supply is ±10% of the nominal voltage, cf. "fol"* §3-3. Meaning, for a 230 V connection, the requirements of voltage lay between 207-253 V, and for a distribution grid at 22 kV, the voltage requirements are between 19.8 kV and 24.2 kV. [35, 36]

One problem with today's grid infrastructure is that bottlenecks occur more frequently than ever. The bottlenecks can occur at every level in the grid. For example, the transmission grid that connects the Norwegian grid from north to south has problems with transmission capacity between different power regions. The northern parts of Norway have a power surplus, but there is a problem exploiting this resource as the transmission lines lack capacity. The transmission capacity to other countries is also a problem. For instance, Sweden has a higher transmission capacity from the north to the southern parts of the country, compared to Norway. This contributes to bottlenecks in the transmission from the north to the south of Norway. [13, 34]

The main reason for bottlenecks on the distribution grid is today's consumption pattern, which deviates distinctly from what it did when the grid first was constructed. At that time, the grid powered mainly lights, refrigerators, and other minor devices. The present demands are much higher, as the power demands have developed over the years. The grid is developed for a yearly increase of power demand around 1-3%. However, there is a rapid development of electricity-driven technology. In addition, the electrification of industrial processes and the implementation of variable renewable energy sources are increasing rapidly. This leads to an imbalance between production and consumption. This can give periods with no production and high consumption, or high production and low consumption. [13, 37]

As a consequence, the power lines reach their maximal transmission capacity. This happens at all levels. When the power lines reach their maximal transmission capacity, bottlenecks occur. Furthermore, much of the production from renewable energy is non-dispatchable. Meaning it can not be controlled. Examples of this are wind and solar power. This makes it more challenging to balance production and demand. Consequently, larger capacity margins are needed in the existing grid. These examples are problems grid companies are facing regarding future grid infrastructure upgrades. The need for additional storage options will probably increase to avoid dimensioning the power grid based on extreme values. Today's government regulations imply that grid companies have sufficient energy and power capacity so that the consumers may use 100% of their demand whenever they want, without limitations. As a result, it will be challenging to consider future intermittent renewable energy supply and increasing consumer demand when planning grid upgrades. [13, 37]

*Regulations on delivery quality in the power system.

2.1.4 Solving Bottlenecks in the Grid

As mentioned in the previous chapter, grid problems and bottlenecks will occur more frequently. Hence, measures in the grid are needed to avoid future bottlenecks and meet customer demands. Today's measures are often expensive and tedious. Grid infrastructure upgrades are such a measure. The assessment of grid infrastructure upgrades can take up to twelve months. The construction time can last four to ten years, depending on what measure is needed. As a result of high expenditures and long development time for such measures in the grid, new and innovative methods could be courses of action to solve grid problems. [1, 38]

Storing energy from variable energy sources and delivering power when and where it is needed can be a possibility for solving grid problems. For instance, low energy demand and low electricity prices during nighttime can be used to store energy for later use. In these cases, hydrogen or batteries can be utilised to store energy at low demands and later deliver this energy back to the grid when demand rises. These energy carriers, and others like it, can help solve the bottleneck problems and ensure voltage quality. [1, 38]

2.2 Future Energy Demands

The Paris Agreement of 2015 set the framework for future energy demands. An agreement was made between 195 countries to keep global warming well below 2 °C. This ambition requires economies worldwide to decarbonise large parts of the world's energy system. The need for action is pressing. Transitioning from non-renewable and carbon-based energy sources requires clean, renewable, and low-carbon solutions. Important focus areas in the energy transition are improving energy efficiency, switching to low-carbon energy carriers, developing renewable energy sources, and implementing carbon capturing and storage (CCS). [1]

What the future energy market will look like is difficult to anticipate. Future demand, electricity generation, and share of renewable energy highly depend on policies and future technological progress. Several reports and studies try to make projections of the future energy market. Such projections are presented in figure 3. These projections are a part of the International Renewable Energy Agency's (IRENA) global roadmap, REmap. The REmap case analyses the deployment of low-carbon technologies to generate a transformation of the global energy system, which can limit the rise in global temperature to below 2 °C above pre-industrial levels by the end of the century. [2]

Figure 3 presents IRENA's projections for total final energy demand, electricity generation, and renewable installed capacity in 2050, based on the REmap case. The figure shows that the electricity share of the total energy consumption will more than double by 2050, while the share of fossil energy carriers will reduce. Furthermore, a higher share of the electricity generation will be from renewable energy. In the REmap case, renewable energy use would nearly quadruple within 2050. The majority of the increased electricity generation will be wind and solar-based. The figure also shows how the installed renewable power capacity might be shared between the different sources. Despite the uncertainty

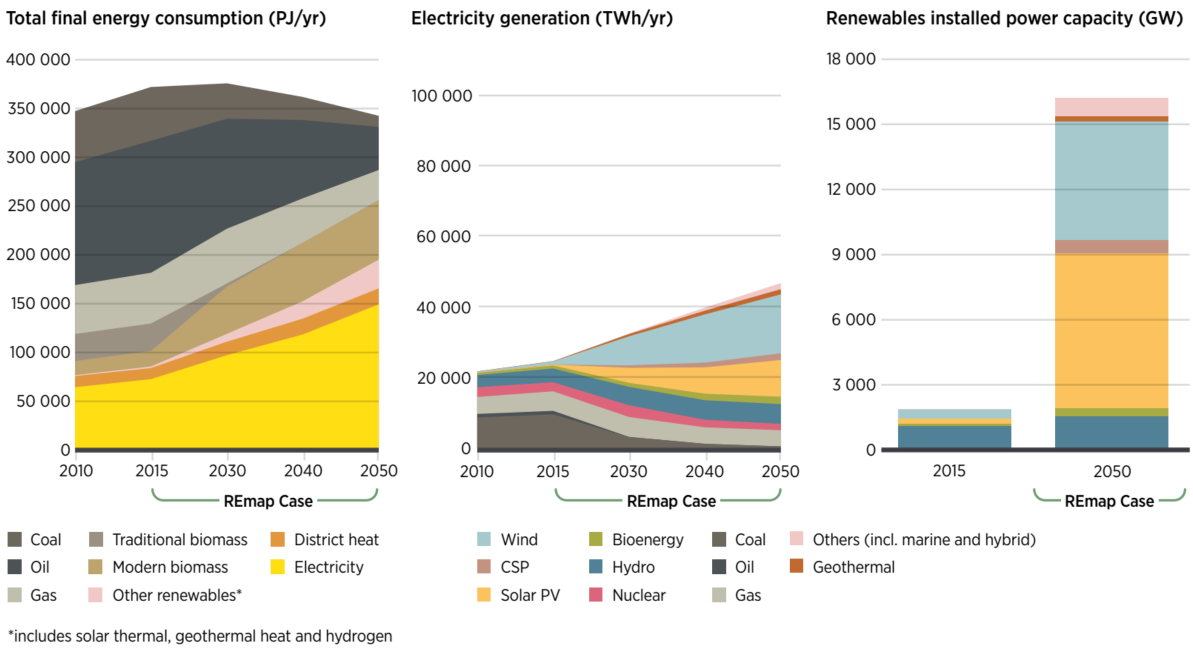

Figure 3: Total energy consumption towards 2050 (PJ/yr), the electricity generation mix (TWh/year) and installed power capacity from renewable sources in 2050 (GW). [2]

regarding future energy demands, IRENA's REmap gives an insight into what the future energy market could look like if the climate goals are to be reached. [2]

The rapid decline of renewable energy costs, electrification of sectors, improved energy efficiency, new technological breakthroughs, and policy actions drive the energy system towards a sustainable pathway. The REmap report is just one of several reports proposing a possible pathway for the energy transition. There is a common consensus in the report, that the future energy market will be based on an increased share of renewable energy and new technologies. Resilient energy systems are just one of the challenges the future energy market faces, and challenges related to this are expected to rise. Several other challenges also have to be solved to secure future energy supply. This is further described in the following chapter. [2, 39]

2.3 Energy Security

Energy security refers to issues of energy supply and access to fuels. The number of sectors considering low-carbon solutions for future energy supply is rising. The increased focus on reducing emissions leads to challenges finding the next energy sources and carriers. If hydrogen is going to be such an energy carrier, both in Norway and globally, it has to be accessible and resilient technologically and economically. In addition, the invasion of Ukraine has led to an accelerating debate on reducing the reliance on Russian hydrocarbons. Russia is a significant supplier of oil and gas to the European continent, and concerns related to energy transition and energy security have emerged after the invasion. There are mainly four aspects of energy security: sustainability, accessibility, affordability, and resilience. This chapter addresses these aspects when implementing hydrogen technology for energy supply. [3, 40–42]

Sustainability

Clean hydrogen is one of the most versatile decarbonisation vectors within several sectors, especially the hard-to-abate ones such as aviation, maritime, and industry. In order to address hydrogen as a clean or low-emission solution, the hydrogen has to be produced from renewable energy or with fossil fuels with CCS. Furthermore, hydrogen allows for further integration of renewably produced energy as hydrogen can store energy, be transported, and utilised in otherwise remote areas. Hence, hydrogen can become a solution for areas lacking low emission solutions. This potentially accelerates the transition to a more renewable energy mix. Regarding end-users, hydrogen can be critical in the decarbonising industry, long-range mobility, heating applications, and power generation. [43]

Accessibility

Hydrogen can be produced using a wide range of energy sources. Globally, hydrogen is mainly produced with fossil fuels. Clean hydrogen produced by electrolysis using renewable energy plays a minor role in the current global hydrogen production. Clean hydrogen can be produced from surplus electricity at periods with low costs, but the number of hours during which surplus energy is available is generally low. By using a CCS-solution, hydrogen production with fossil fuels can be a low-emission solution. The wide range of production possibilities secures hydrogen availability. However, the solutions are currently linked to high costs. Consequently, the cost of clean hydrogen can become a limitation to accessibility. Moreover, there are also some limitations to distance when transporting hydrogen. Currently, hydrogen transportation is relatively expensive, limiting the utilisation areas. [3]

Hydrogen is an energy carrier that can flexibly store energy. Therefore, there is much potential for hydrogen-based fuels. However, if hydrogen and hydrogen-based fuels, such as ammonia, are to be adopted in the energy mix, technological solutions must be available. Piloting and demonstration projects of hydrogen and hydrogen-based fuels in new applications could be essential for reduced production costs, hence also the accessibility of hydrogen. [41]

Affordability

The affordability of hydrogen is an important aspect when evaluating energy security. In many commercial applications, the energy cost is important in terms of global competitiveness. The cost of hydrogen can be calculated using a LCOH. LCOH is an approach that looks into the costs of providing services and installations for hydrogen production. The cost of hydrogen will be essential for implementing a hydrogen society. Current estimates show that blue hydrogen is two times the price of natural gas, and green hydrogen is five times the price after long-distance shipping. Predictions show trends of the hydrogen price falling fast. However, there is a need for financial support for hydrogen to become economically viable over the next decade. Based on the current energy costs, the utilisation of clean hydrogen is less profitable than fossil fuels. In the future, the environmental benefits of the different hydrogen applications need to be considered when pricing the fuel. In addition, fossil fuel prices still do not mirror the high levels of pollution and the health risks they incur. As fuel prices increasingly reflect their true social costs, the competitiveness of clean hydrogen will be supported respectively, accelerating their market value. [40, 41, 44]

Resilience

Energy resilience is crucial as energy delivery failure could affect the operation of many different sectors. Most prominent being in healthcare, where energy resilience could be critical as energy outages could mean people's lives being at stake. [45]

Hydrogen provides energy resiliency in multiple ways through the feature of storing energy. Hydrogen can balance peaks in the grid by storing power when excess low-cost energy is available. When the electricity demand on the grid increases, hydrogen can be converted back to electricity and supply the grid. Hence, hydrogen can store energy that is not in demand immediately by the grid. Hydrogen produced with intermittent renewable energy can be utilised when there is a shortage of solar or wind power. Furthermore, hydrogen can be transported to off-site locations, enabling diversification of energy resources across geographies. [46]

Fuel cells can also be utilised to provide power supply in remote areas or, perhaps more importantly, to facilities dependent on backup power solutions such as hospitals or data centers. Backup power for key infrastructure can aid in emergency power response to prevent loss of productivity in the event of grid outage incidents. Fuel cell backup systems are often paired with a battery to provide instant start capability, as the fuel cell system needs seconds to ramp up. [47]

3 Hydrogen Production and Storage

Despite the rapid increase in the global interest in hydrogen, it has been used for various purposes for a long time. Electrolyser and fuel cell technology have been known and researched since the 19th century. The first electrolyser appeared in 1800, while the first fuel cell demonstration was in 1839. Early electrolysers were mainly used for ammonia production using hydropower. Much of the technological development has been driven by the space race and military activities. In recent years hydrogen has been used in smaller applications and industrial processes. Even tough the technologies has been known for around 200 years, the fundamentals still remain the same. Today, hydrogen is an energy carrier that can contribute to the decarbonisation of several sectors. This period is expected to take hydrogen from small-scale to widespread use. This part will provide an overview of the fundamentals of hydrogen as an energy carrier, the different production methods, their characteristics, and how hydrogen is stored and transported. [48, 49]

3.1 Hydrogen Fundamentals

Hydrogen (H) is the lightest element in the periodic table and the most abundant element in the universe. H_2 has a specific energy density of 33.34 kWh/kg based on LHV. As figure 4 displays, the specific energy density of hydrogen is far higher than of other energy carriers. With this attribute, in addition to only emitting water when used, hydrogen has a huge potential as a clean and sustainable energy carrier. [50]

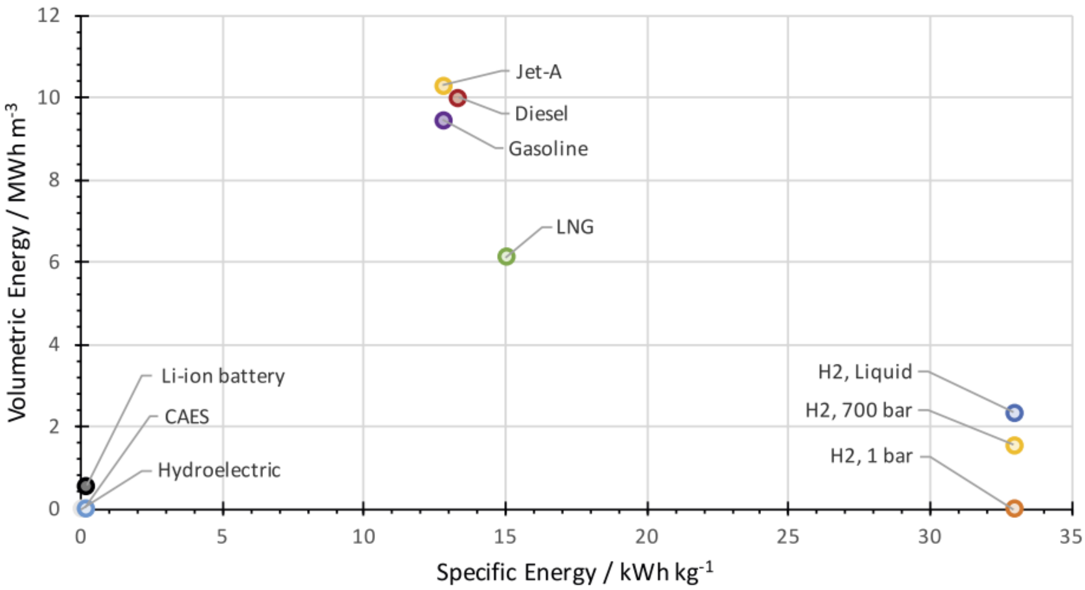

Figure 4: Graphical overview of energy densities for different energy carriers. [51]

Despite being one of the lightest energy carriers in the world, the volumetric energy density of hydrogen is low compared to other energy carriers. This is shown in figure 4. As the figure shows, energy carriers such as diesel and gasoline are heavier than hydrogen, but require less volume. Hydrogen can reach higher volumetric densities, such as in liquid state or at high pressures. [51]

3.2 Hydrogen Market

The European ambitions for energy transition are high. New solutions are necessary to fulfill these ambitions. Hydrogen can be a solution to various energy challenges. As a result, the interest in hydrogen and hydrogen systems is growing in European countries and individual companies. The European Commission has presented a hydrogen strategy. The aim is to make the EU a pioneer in the use of hydrogen, in addition to contributing to the widespread use of hydrogen by 2050. [52]

Despite the increasing interest in hydrogen as an energy carrier, several areas already have long experience with the use of hydrogen. According to IEA, the global demand for pure hydrogen was 72 Mt in 2020. If hydrogen mixed with other gases is included, the total demand for hydrogen was 120 Mt in 2020. The last 28 Mt of demand is from hydrogen mixed with carbon-containing and other residual gases. [53]

Today, hydrogen is mostly used in a few sectors. Industrial applications dominate the usage. In the chemical industry, hydrogen is used to produce ammonia, fertiliser, and methanol. Further, in the petrochemical industry, hydrogen is used for oil refining. In addition, the use of hydrogen is increasing in the steel industry, as a result of the considerable pressure regarding their large emissions. [3, 54]

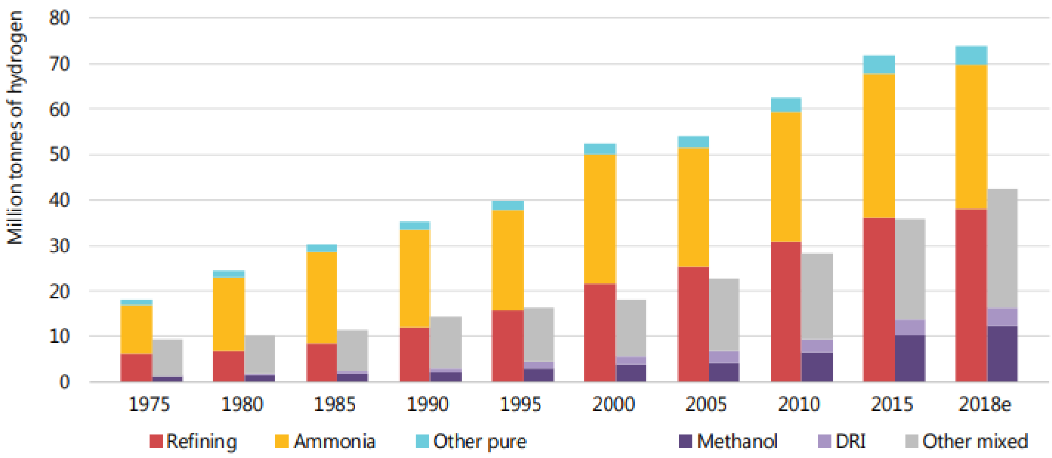

Figure 5: Global annual hydrogen demand since 1975 until 2018. [3]

As seen from figure 5, the major part of the global hydrogen demand is from industrial applications. The figure shows how the demand for hydrogen increased from 1975 to 2018. As illustrated, hydrogen is not only used in industrial applications. Other examples are for transport and power generation. However, the use of hydrogen in most transport segments is still at an early stage. Further research and demonstration projects are required before it becomes commercially available. Cars account for the vast majority of hydrogen used in today's transport sector. The number of registered fuel cell electric vehicles worldwide reached nearly 26 000 in 2020. In addition, both buses and trucks running on hydrogen are in operation, but the amount is still relatively low. Hydrogen is used in some small-scale power generation applications. However, the demand for hydrogen in power generation and other applications is expected to multiply. [3, 41, 55]

Hydrogen production today is primarily based on natural gas and coal. In 2020, these sources accounted for 95% of hydrogen production combined. Use of fossil fuels for hydrogen production results in significant emissions of CO_2. Currently, there is minor production from renewable energy sources, mainly limited to demonstration projects. However, the capacity of electrolysers doubled over the last five years. Furthermore, current projects could drastically increase electrolyser capacities if proven successful. This would significantly increase the share of hydrogen produced from renewable energy. [48, 53]

The market size of hydrogen generation was estimated at around $130 billion in 2021 [56]. Furthermore, the total hydrogen market is valued at $174 billion according to IRENA [57]. A tremendous increase of investments in hydrogen technologies are expected in the next years and towards 2030. Several countries have already developed strategies, roadmaps, and funding schemes to increase the use of hydrogen in the future. [41]

3.2.1 Future of Hydrogen

As described in the previous chapter, several countries have adopted hydrogen strategies and the market is growing rapidly. These countries have now committed a total investment of at least $37 million. The private sector has announced an additional investment of $300 million. However, higher investments are needed to reach the net-zero ambitions by 2050. According to IEA, investments of $1 200 billion in low-carbon hydrogen supply and use, are required through 2030 to achieve the 2050-ambitions. [53]

It is not easy to anticipate the size of the future hydrogen market and for which applications hydrogen will be used. Bjørn Simonsen in Saga Pure mentions that future scenarios and forecasts tend to be too optimistic. However, hydrogen is the only way for some industries to reduce emissions. Examples are the steel and glass industry. As a result, hydrogen will undoubtedly have an important role in the future energy market. Figure 6 illustrates the range of possible future hydrogen demands. [14]

As illustrated in figure 6, the future demand for hydrogen highly depends on the ambitions to reduce global warming. In the figure, the ambitions are divided between high (<1.8 °C), medium (1.8-2.3 °C) and low (>2.3 °C). The figure is a result of 13 scenarios from 8 different reports. However, despite the broad range of future demands, all estimates predict a limited, but steady growth of hydrogen demand until 2030. The future cost reduction will be important for the widespread use of hydrogen. Figure 7 illustrates future prices for renewable hydrogen. [58]

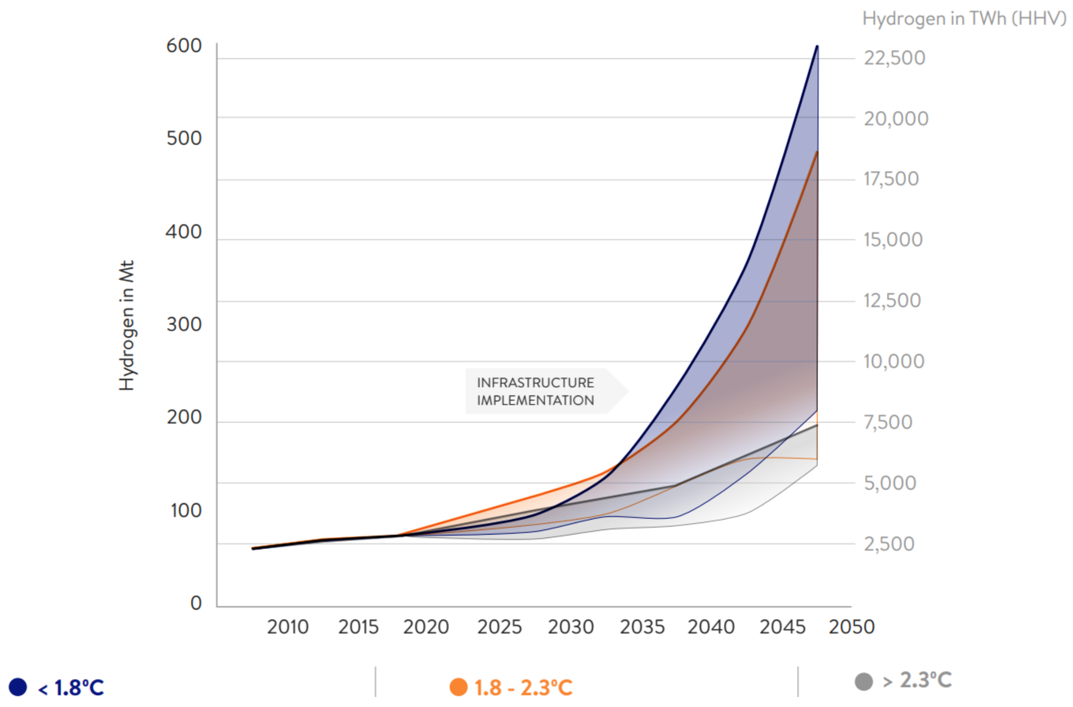

Figure 6: Range of different hydrogen demand assessments by 2050. The different assessments are based on different scenario assumptions. [58]

Figure 7 shows the range of future prices of renewable hydrogen. The figure is based on six reports, including 16 different scenarios of forecasted hydrogen production prices. Common for all studies is that they anticipate a significant price decrease towards 2030 due to falling electricity costs, technology improvements, and economies of scale. [58]

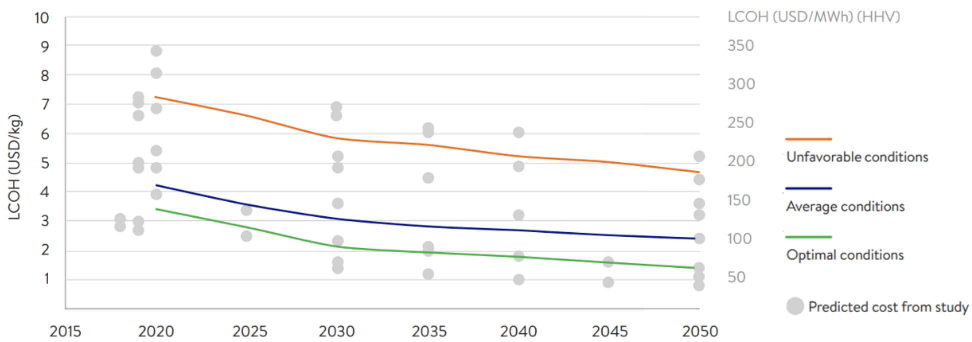

Figure 7: Future production cost of renewable hydrogen, based on different price development scenarios regarding the production conditions. [58]

Both figure 6 and 7 illustrate how uncertain the future of hydrogen is. Increased demand and falling prices are likely to happen, but it is difficult to anticipate to what extent. However, increased demand is linked to technological development. The Hydrogen Council estimates that by scaling electrolysis up to 70 GW, the price of electrolyser costs will come down to around \$400/kW. [58, 59]

3.3 Hydrogen Production Methods

There are several ways to produce hydrogen. The flow chart in figure 8 shows the different hydrogen production methods. Currently, the yearly global hydrogen production is at about 500 billion cubic meters. About 95% of this hydrogen is produced using non-renewable fossil fuels. For instance, trough steam methane reforming (SMR). These methods produce hydrogen of low purity, in addition to emitting greenhouse gasses. For processes with CO_2 emissions, CCS might be an attractive method to make hydrogen production more sustainable and environmentally friendly. Especially for areas with low-cost natural gas and suitable underground reservoirs for storage. [48, 50]

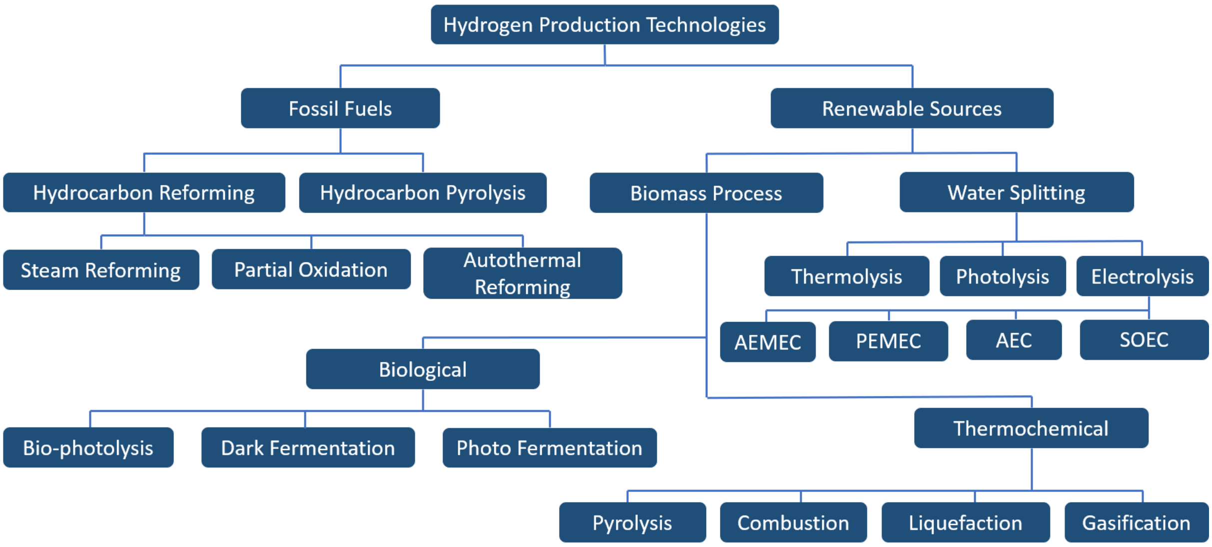

Figure 8: Various hydrogen production methods. [50]

Moreover, emissions from hydrogen production with fossil fuels can also be low-carbon with methane pyrolysis. In this case the carbon ends up in a solid state rather than as CO_2. As figure 8, hydrogen can also be produced with electrolysis, solar energy (i.e. photosynthesis) and bioenergy, among others. Nevertheless, each hydrogen production method has its limitation. For instance, electrolysis often requires more electricity than other methods. Bioenergy might be better suited for other use areas, rather than to be converted to hydrogen. Furthermore, CCS does not lead to zero emissions and requires huge reservoirs for CO_2 storage. Hence, despite many pathways, no clear method is yet proven to be the absolute best. Due to the many different ways to produce hydrogen, it is often sorted into different colours that represents how environmentally friendly it is. These colours are presented in table 2. [48]

Green, blue, and grey hydrogen are the most common types of hydrogen today.

Table 2: The different colours of hydrogen. [60]

Green hydrogen is made from clean renewable energy sources, such as wind, solar, and hydropower by water electrolysis.
Blue hydrogen is produced from natural gas with SMR, but CCS is used to make it more environmentally friendly.
Grey hydrogen is produced from natural gas or oil, using SMR, but without CCS. Thus, CO_2 is emitted to the environment. This is the most common application today.
Black hydrogen is produced with coal or ignite, this method is highly emissive and environmentally damaging.
Pink hydrogen is created from electrolysis like green hydrogen, but the electricity is generated by nuclear power.
Turquoise hydrogen uses a process called methane pyrolysis. The products of this process are hydrogen and solid carbon. The method has not yet been proven at scale.
White hydrogen is the hydrogen that naturally occurs in underground deposits. There are no present methods to utilise this hydrogen.

Steam Methane Reforming

As mentioned, the most common application today is SMR. Natural gas is mixed with steam at a high temperature (700-900 °C) in a reformer during the process. Equation 1 and 2 display the two key reactions in SMR. [61]

1. In the first reaction, presented in equation 1, the steam and gas reacts and produces hydrogen and carbon monoxide, with nickle as a catalyst. This reaction is strongly endothermic.

$$CH_4 + H_2O \longrightarrow CO + 3H_2 \tag{1}$$

2. In the second reaction, presented in reaction 2, the carbon monoxide reacts with steam. This reaction is called the water-shift-reaction. Here, additional hydrogen can be recovered by lower temperature gas shift. The reaction is mildly exothermic.

$$CO + H_2O \longrightarrow CO_2 + H_2 \tag{2}$$

Even though SMR is the most applied method today, the method is mainly used as industrial input. In industrial input, hydrogen is not used as an energy carrier for extensive use but in other processes such as ammonia production. [62]

As equation 2 reveals, the SMR process is not carbon-neutral, and on a global scale, the CO_2 emissions from SMR are significant. However, the process can be combined with various CCS techniques and become more eco-friendly. [61]

3.4 Water Electrolysis

The most common way to produce green hydrogen is through water electrolysis. Splitting water molecules with electrolysers is a method that has been used for over two centuries. From the early 1800s, electrolysers were mostly used for ammonia production, and hydropower often generated the power for the process. At the time, Norway was one of few countries using this technology, especially at Norsk Hydro. Because of the high prices of electrolysis, the method is presently often applied when high purity is necessary. Hydrogen can reach a purity of 99.99% when it is produced with electrolysis of water. Electricity is used to split water molecules. The electrolysis reaction produces hydrogen and oxygen. The overall electrolysis reaction is displayed in equation 3. [50]

$$2H_2O + energy \longrightarrow 2H_2 + O_2 \tag{3}$$

The electrolysis process is endothermic, which means that the reaction needs energy. Gibbs free energy (ΔG) can calculate the minimum energy required to drive the chemical reaction. Since the reaction is non-spontaneous, ΔG is positive. Gibbs free energy can be calculated using equation 4 at standard conditions. [50, 51]

$$\Delta G = -zFE_{rev} \tag{4}$$

F represents Faraday's constant (F = 96485 C/mol), and z represents the number of electrons in the chemical reaction. The reversible cell voltage, E_{rev}, represents the minimum required applied voltage to drive the reaction. E_{rev} can be calculated with equation 5, where E_{anode} and $E_{cathode}$ represents the voltage of the half-cell reactions. The half-cell reactions of the different electrolysis technologies differ from each other. Hence, E_{anode} and $E_{cathode}$ is different for the different cell technologies. Despite changing half-cell voltages, E_{rev} remains the same. [50]

$$E_{rev} = E_{anode} - E_{cathode} = -1.23V \tag{5}$$

Because of other losses in electrolysis, such as heat, more voltage has to be applied for the cell reaction to happen. This voltage is called the cell voltage, E_{cell}. For the sake of simplicity, this thesis will not go into more depth on E_{cell}. Nevertheless, these losses are important to minimise as much as possible, to maximise the efficiency. The efficiency, which is calculated with equation 6, is called the faradic efficiency, η_f. [50, 63, 64]

$$\eta_f = \frac{E_{rev}}{E_{cell}} \tag{6}$$

In reality, the reaction needs more energy than what E_{rev} represents because of other than ideal conditions. Hence, it is more accurate to use the change of enthalpy (ΔH) shown in equation 7, instead of the ΔG, like in equation 4. [50, 64]

$$\Delta H = \Delta G + T\Delta S \tag{7}$$

In equation 7, T represents the temperature, and ΔS represents the change in entropy. At standard conditions, the change in enthalpy is $\Delta H = 285.84$ kJ/mol†. Hence, a new minimum required voltage can be calculated with equation 8.

$$U_{TH} = -\frac{\Delta H}{zF} = -\frac{\Delta G + T\Delta S}{zF} \tag{8}$$

Where U_{TH} is the thermo-neutral voltage. Conditions can make the thermo-neutral voltage vary. Furthermore, with U_{TH} a new efficiency can be calculated with equation 9, where η_{TH} represents the thermo-neutral efficiency. [50, 63]

$$\eta_{TH} = \frac{U_{TH}}{E_{cell}} \tag{9}$$

3.4.1 Components in an Electrolysis Cell

To understand water electrolysis better, it is important to look at the different components in an electrolyser. An electrolyser needs many components to function optimally. The most important components are two electrodes, an electrolyte, a separator, and a direct current (DC) from an external source to work. Since an electrolyser needs direct current (DC) to work, and the grid operates with alternating current (AC), a rectifier converts AC to DC when the electrolyser is connected to the grid.

The anode is the positive, and the cathode is the negative electrode. At the anodic electrode, liquid deionised water is fed. The H_2O molecules are oxidised, leading to the production of H_2 and O_2. The O_2 is in the gaseous phase and is extracted from the cell. The oxygen may be compressed and stored as part of the process. The external circuit is where the electrons circulate. The H^+-ions migrate across the separator. The separator separates the two electrodes and avoids mixing oxygen and hydrogen. If oxygen and hydrogen are mixed, it is highly explosive. The separator can either be a porous or solid material. The porous separator is called a diaphragm and is used in Alkaline electrolysis. The solid separator, which is mainly used in PEMECs, is called a solid polymer electrolyte membrane.

†Based on HHV

3.4.2 Water Electrolysis Technologies

There are several water electrolysis technologies. This part will present different technologies of water electrolysis.

Alkaline Electrolysis Cell

Alkaline electrolysis is the most used electrolysis technology today. The alkaline electrolysis cell (AEC), which is illustrated in figure 9, has been used for over two centuries. It is the most successful and mature electrolysis technology to date. The electrolyte ensures an alkaline environment, which does not need acid-resistant materials. This makes the AEC cheap. [50, 61, 65]

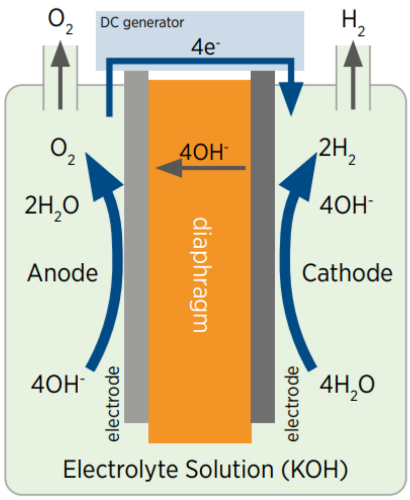

Figure 9: AEC. [65]

In an AEC, the electrolyte is liquid. It is typically a potassium hydroxide (KOH) or sodium hydroxide (NaOH) solution. KOH is preferably used due to its ionic conductivity, where the wt.% is usually between 25-30%. The anode and cathode typically consist of nickel-coated iron. The electrodes are separated by a diaphragm, which conducts the OH^- anions.[61]

Even though all electrolysis methods have the same total reaction, ref. equation 3, the anode reaction 10, and cathode reaction 11, are different. [65]

$$Anode : 4OH^- \longrightarrow 2H_2O + O_2 + 4e^- \tag{10}$$

$$Cathode : 4H_2O + 4e^- \longrightarrow 2H_2 + 4OH^- \tag{11}$$

The AEC have the lowest capital expenditures (CAPEX) of the electrolysis technologies. The CAPEX varies with scale but typically varies between 900 - 1700[‡] €/kW. The AEC stack lifetime reaches between 60 000 - 90 000 hours. The AEC has some disadvantages, like electrolyte leakage, corrosion, slow electrochemical kinetics, and high polarisation losses. Further, the technology has problems with intermittent renewable energy sources. The maximum operational current density is around 400 mA/cm^2, which is low compared to other electrolysis technologies. The AEC also needs a larger volume to produce hydrogen at the same rate as other technologies. This can be a problem with area restrictions. The AEC usually operates at about 1.8-2.4 V, which is higher than for other electrolysers. The efficiency of an AEC varies between 60-80%. [66, 67]

[‡]The price is calculated for 300kW - 5MW systems.

Polymer Electrolyte Membrane Electrolysis Cell

The polymer electrolyte membrane electrolysis cell (PEMEC) has proven to be one of the best ways to produce green hydrogen. Figure 10 shows the working principles of a PEMEC. The membrane in the cell conducts H^+-protons from the anode to the cathode and therefore works as an electrolyte. Hence, there is no need for a liquid electrolyte in a PEMEC. The proton exchange membrane has many advantages, such as low thickness, high proton conductivity and low gas permeability. The membrane is responsible for around 24% of the overall cell cost. Currently, Nafion membranes are the most common membrane in PEMEC. This is because of the high current densities, which can reach as high as 2 A/cm^2. It also has higher durability and proton conductivity compared to other PEMs. [50]

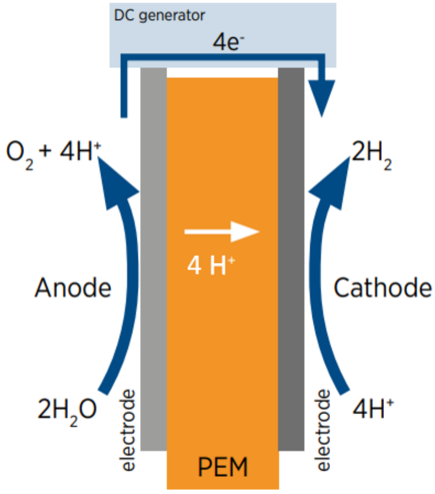

Figure 10: PEMEC. [65]

The half cell reactions for the PEMEC are presented in equation 12 and 13. [50, 65]

$$Anode : 2H_2O \longrightarrow 4H^+ + O_2 + 4e^- \tag{12}$$

$$Cathode : 4H^+ + 4e^- \longrightarrow 2H_2 \tag{13}$$

The biggest disadvantage of a PEMEC is the harsh acidic environment, which creates the demand for noble materials such as platinum and titanium. These noble materials can withstand the acidic conditions for long periods. However, they are far more expensive than, for instance, nickel-coated iron electrodes in an AEC. As a result, the PEMEC stacks are more expensive than the AEC, with prices varying between 1700-2500[§] €/kW [50, 67]

[§]The price is calculated for 300-500 kW systems

AEMEC and SOEC

Even though hydrogen production from electrolysis is an old technology, several new methods are developing. The anion exchange membrane electrolysis cell (AEMEC) and the solid oxide electrolysis cell (SOEC) are two new electrolysis technologies. However, both AEMEC and SOEC, have not yet been utilised at larger scale.

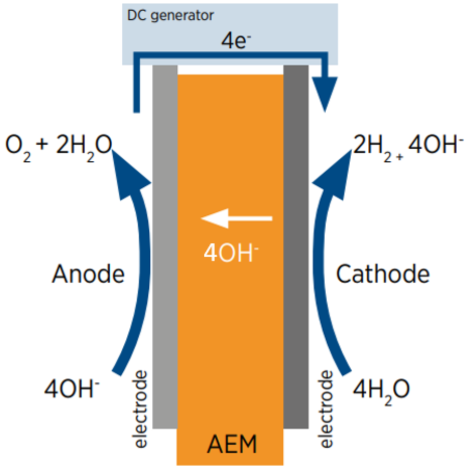

Figure 11: AEMEC. [65]

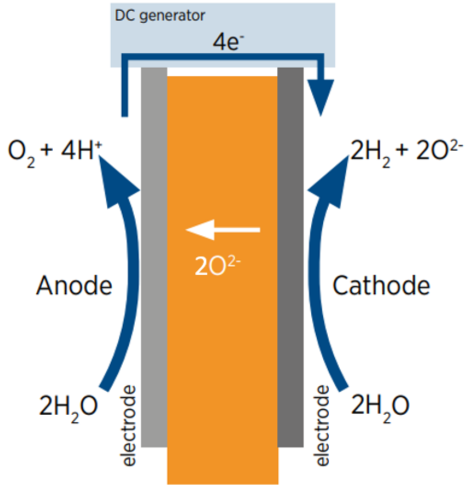

Figure 12: SOEC. [65]

The AEMEC is displayed in figure 11. Like the PEMEC and AEC, the technology is a low-temperature electrolysis technology as it operates at temperatures around 50-60 °C. Further, the AEMEC does not need acid-resistant materials. It still manages to have the simplicity and efficiency as the PEMEC. Basically, the AEM electrolysis benefits from both the PEMEC and the AEC. Still, it is a developing technology. Hence, the technology has not been commercialised yet. [50, 68]

The method is pretty similar to the alkaline electrolyser, but in comparison it does not need a liquid electrolyte. Furthermore, the diaphragm is substituted with an AEM. Thus, the AEMEC has the same anode and cathode reactions as the AEC. These are displayed below in equation 14 and 15.

$$Anode : 4OH^- \longrightarrow 2H_2O + O_2 + 4e^- \tag{14}$$

$$Cathode : 4H_2O + 4e^- \longrightarrow 2H_2 + 4OH^- \tag{15}$$

Figure 12 illustrates the SOEC. The SOEC technology is based on thermodynamic analyses of the water-splitting reactions. The analyses show that ΔG of the reaction decreases at cell temperatures between 800 - 1000 °C. Hence, the SOEC is produced for high-temperature steam electrolysis. It is the only high-temperature electrolysis method presented in this thesis. Ceramics are used as the electrolyte in the SOEC. Therefore the electrolysis cell has low material costs. The SOEC also has high electrical efficiency. In addition, it is possible to recycle the SOEC process's heat to produce more steam for further SOEC electrolysis. The high process temperature of the SOEC also creates degradation challenges of materials, which is one of the main problems with the technology. [3, 67]

One of the SOEC's features is that it can be operated in reverse mode. Meaning it can operate as a fuel cell. This is unlike the PEMEC, AEC, or the AEMEC. This feature can, for instance, provide flexibility and balance to the electric grid. Hydrogen could be produced when the power demand is low and produce electricity when the demand is high. Hence, the overall utilisation rate of the SOEC would increase. [3, 67]

The half-cell reactions of the SOEC are presented in equation 16 and 17.

$$Anode : 2O^{2-} \longrightarrow O_2 + 4e^- \tag{16}$$

$$Cathode : 2H_2O + 4e^- \longrightarrow 2H_2 + 2O^{2-} \tag{17}$$

3.5 Compression of Hydrogen

As mentioned in chapter 3.1, hydrogen is an energy carrier with a high specific energy density (kWh/kg) but with a low volumetric energy density. This can create problems when storing and transporting the gas. Compressors need electricity to operate. The efficiency of hydrogen compression is about 93% [12]. A compressor can compress hydrogen so that the volumetric energy density rises. Table 3 displays the change of energy density at different pressures, this is also graphically displayed in figure 4. [69]

Table 3: Gravimetric and volumetric energy densities at different pressures. The volumetric energy density is based on LHV. [70]

	Atmospheric Pressure	350 Bar	700 Bar
Volumetric density [kg/m^3]	0.09	21	42
Volumetric energy density [kWh/m^3]	3	700	1400

As table 3 shows, the volumetric energy density for hydrogen is very low at atmospheric pressure. Hence, hydrogen will be compressed when stored or used for mobile applications. When hydrogen is electrochemically produced, it is also possible to compress the hydrogen in the process. As a result, hydrogen is usually produced at higher than atmospheric pressures. Pressures of 350 bar and 700 are often used for compressed hydrogen. It is possible to develop pressurised water electrolysers up to 200-300 bar with PEM technology. However, it is impractical to develop such electrolysers because of the cost of high-pressure equipment and possible safety problems. Hence, hydrogen is often produced at 20-30 bar, and compressors compress hydrogen further. Normally, 350 bar is the minimum required pressure for applications where the volume does not matter too much. These applications include larger vehicle transport like busses and trailers, as well as stationary applications. While 700 bar is used when the volume is of great concern, such as for passenger cars and smaller mobile applications. [67, 69, 70]

3.5.1 Hydrogen Compressors

The typical way to compress hydrogen is with mechanical compression. Reciprocating or rotary positive displacement compressors, or centrifugal compressors are the most used compressors for gaseous hydrogen. The compression of hydrogen with positive displacement compressors can be challenging due to the size of hydrogen, which makes it necessary with tight tolerances to prevent leakage. Reciprocating compressors have a very high compression ratio. The method uses a motor that makes the piston or diaphragm move back and forth. The motion reduces the volume and compresses the hydrogen. Rotary compressors, on the other hand, use gears or other tools that rotate, to compress hydrogen. Centrifugal compressors use a rotating turbine at very high speeds to compress the gas. The application is best for pipeline applications and has a moderate compression ratio. [69]

3.6 Different Storage Technologies

As a result of the growing concern about climate change, the environmental impacts of fossil fuels, and challenges with grid capacity, many different storage technologies are being studied. Energy storage technologies can help better exploit intermittent renewable energy. Storage technologies can provide grid flexibility. In addition, they can respond quickly to changes in power demands.

Today, fossil fuels are the most used form of energy. This is a result of the transportability and the practicality they provide. As renewables have become more prominent on the electrical grid, there has been a growing interest in systems that can store clean energy. The choice of storage technology depends on the application. Different storage technologies are presented in figure 13.

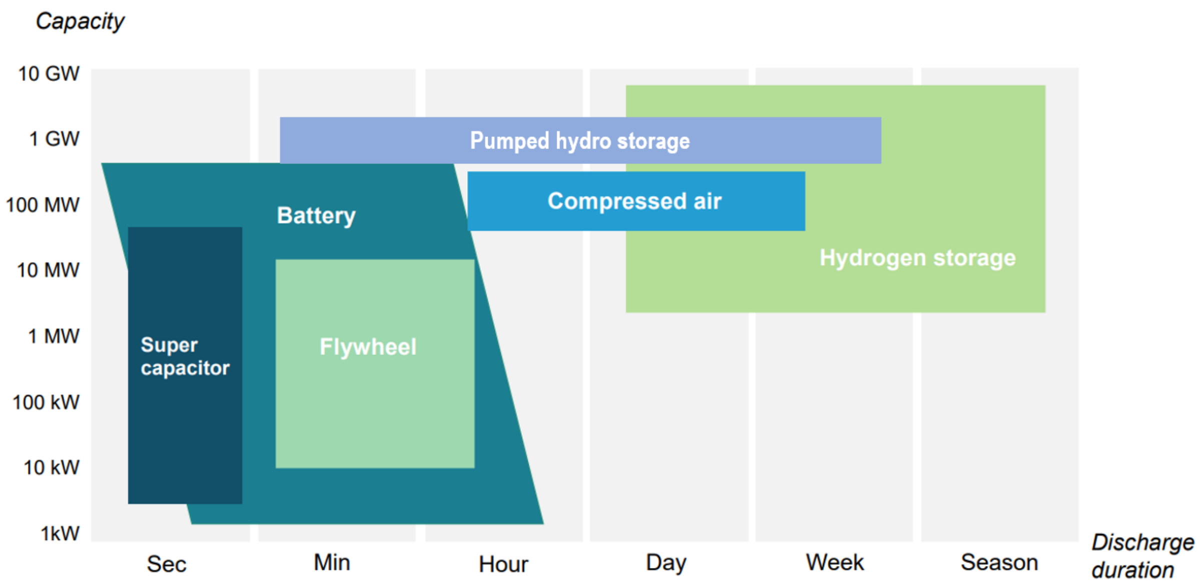

Figure 13: Comparison of different energy storing technologies and their properties in discharge duration and capacity. Modified figure from [71]. Colours are changed for better readability.

Figure 13 illustrates the capacity and discharge duration of common storage technologies. As illustrated, it is significant variations in what the different technologies can provide when it comes to storage capacity and discharge duration. The discharge duration of super capacitors is as short as seconds. Hydrogen, on the other hand, can provide much longer discharge durations. What technology to chose is highly dependent on the application. As shown in figure 13, hydrogen can be used for a large range of capacities and discharge times. Green hydrogen is a good and environment-friendly alternative despite current limitations compared to other storage technologies and fossil fuels. However, as illustrated in the figure, other storage technologies might be preferred in some cases. Batteries can be suitable for short-time storage and when the demand changes quickly. Batteries can be used to balance demand within seconds to hours. Hydrogen, on the other hand, can store energy for longer periods. Such long-time energy storage is preferred for storing large amounts of surplus renewable energy. By providing high capacity and seasonal storage, a higher share of renewable energy could be feasible. Large amounts of electricity can be stored in batteries. However, hydrogen has a significantly better capacity than batteries. Nevertheless, the duration is the major concern when comparing batteries and hydrogen for storage. This also affects for which applications they are suitable. [71, 72]

3.7 Hydrogen Storage

In order to get a complete overview of the use of hydrogen, it is essential to have knowledge about how hydrogen is stored. This chapter will describe the different hydrogen storage technologies, how they work, as well as advantages and disadvantages. The chapter will have a closer look at compressed hydrogen storage since this is the technology used with the fuel cell technology in this case. The degradation of hydrogen vessels will be presented briefly in chapter 3.10.

3.7.1 Types of Hydrogen Storage

Hydrogen has the potential to store electric energy for weeks and even months. It also has the potential to store large amounts of electric energy. The energy density of hydrogen is no more than 1/3000 of gasoline. This could result in huge storage volumes. As a result of the low energy density, it has to be increased in order to store sufficient amounts, at appropriate volumes. At least one of the following features is required to store sufficient quantities of hydrogen: high storage pressure, low storage temperature, or use of a material that attracts a large number of hydrogen molecules. Consequently, there are several different methods to store hydrogen. Different types of hydrogen storage is presented in figure 14. [61, 73]

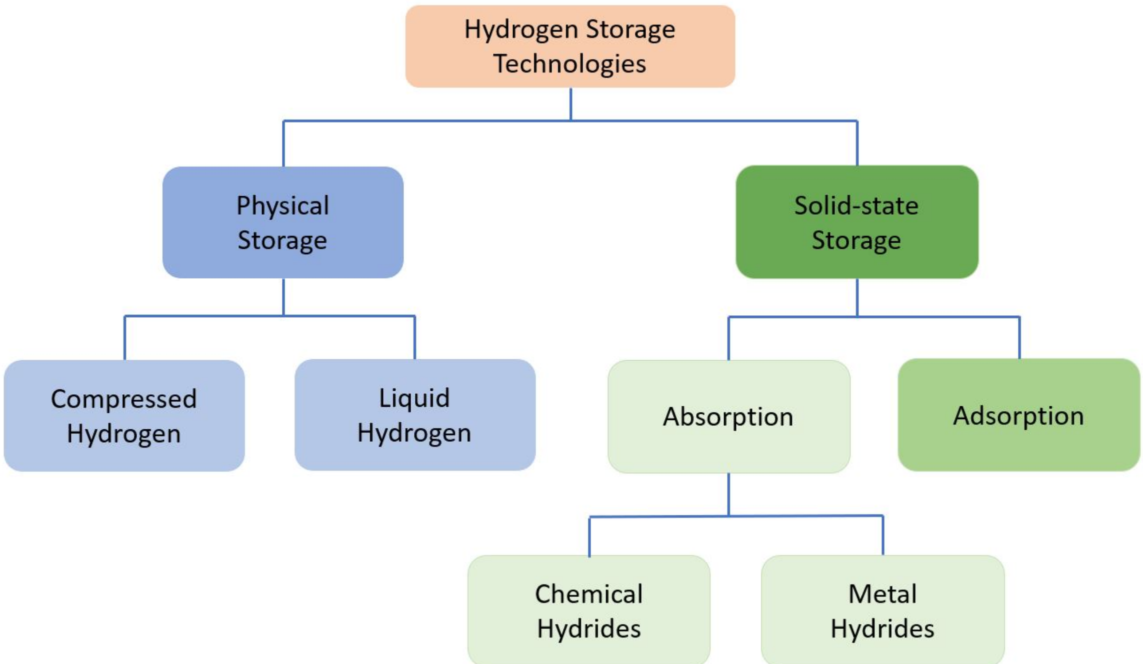

Figure 14: Overview of different types of hydrogen storage. [61, 74]

The hydrogen storage technologies can be divided into two main groups. The main groups have several sub-groups, as illustrated in figure 14. The two sub-groups are physical-based and material-based storage. Physical-based storage is divided into compressed hydrogen storage, liquid hydrogen storage, and cold compressed storage. Cold compressed storage combines compressed and liquid hydrogen storage. Material-based storage has two main sub-groups. These are chemical sorption and physical sorption. [73]

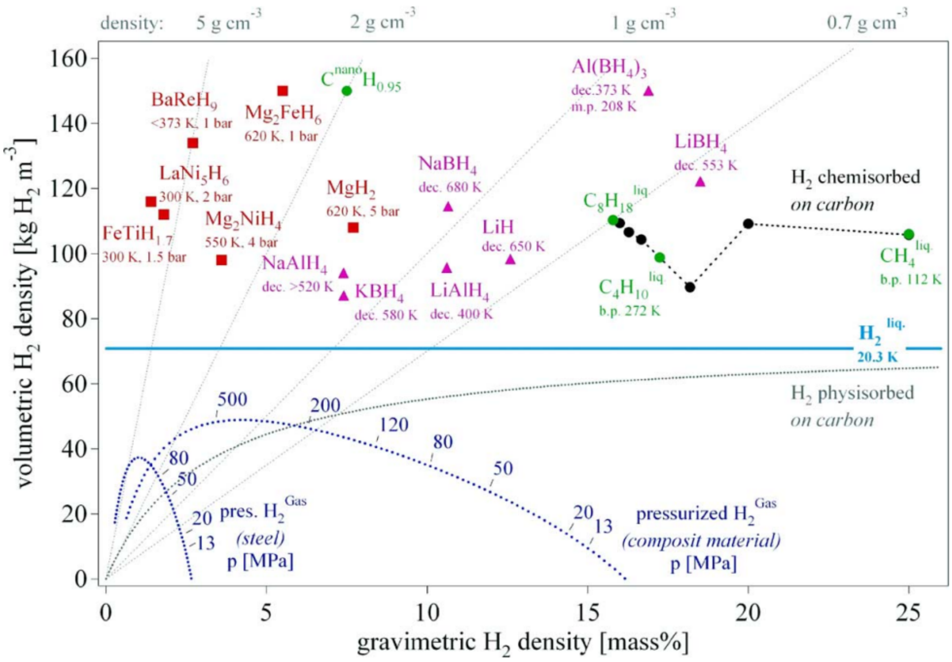

Figure 15: Volumetric and gravimetric density of some selected hydrogen storage methods. [74]

Compressed and liquid hydrogen are the most common hydrogen storage methods today. However, future demands will require a much wider variety of storage options. No hydrogen storage technique can be considered to be the best fit for all applications. The choice of storage method depends on the volume to be stored, the geographic availability, the duration of the storage, and the required speed of discharge. Figure 15 shows the volumetric and gravimetric density of different storage technologies. The figure compares compressed, liquid, and some selected metal hydrides. The figure is made with a focus on metal hydrides. Consequently, some storage technologies are excluded, such as ammonia and methanol. [3, 75]

As presented in figure 15, metal hydrides exhibit very high volumetric and gravimetric hydrogen capacities, exceeding the volumetric density of both compressed and liquid hydrogen. As a result, the potential for storing large amounts of energy in these materials is huge. However, compressed hydrogen is still the most convenient and most used way of storage. The benefits of using composite material instead of steel for storing compressed hydrogen are also shown in figure 15. As illustrated, this would increase the gravimetric and volumetric density of the compressed hydrogen. With liquefaction, the volumetric density can be improved even more. Liquid hydrogen has a much higher energy density than compressed hydrogen. This provides some benefits compared to compressed hydrogen. [74]

Liquid Hydrogen

Liquefaction of hydrogen is a way to solve the problem of low hydrogen densities. Extremely low temperatures are needed to do this. Hydrogen needs to be liquefied at -253 °C. Liquefaction of hydrogen is a well-established technology. However, it is a very time-consuming and energy-intensive process. As much as 40% of the energy content can be lost in the process, compared to approximately 10% energy loss for compressed hydrogen. In addition, some of the stored liquid hydrogen will evaporate, also called boil-off. This will result in additional losses. These losses are proportional to the ratio of surface area to volume. Boil-off losses can be reduced if larger storage vessels, with lower ratios between surface area and volume are used. As a result, liquid hydrogen is well suited for large-scale storage. [61, 76]

Liquid hydrogen is stored in cryogenic tanks. These tanks are designed to prevent heat inleak. The tanks are usually spherical and vacuum insulated. The vacuum insulation consists of two walls with a vacuum between them. This insulation will minimise the heat transfer between the hydrogen and the surrounding area. This will reduce boil-off during storage and hence the storage losses. [77]

Liquid hydrogen is the preferred method of storage when hydrogen is transported over long distances and in large volumes. This is a way to make it cost-competitive compared to other hydrogen storage methods. Over long distances, liquid hydrogen is a better economic option than compressed hydrogen. Much larger volumes of hydrogen can be transported when the hydrogen is liquid. Thus, the cost per kilogram of hydrogen will be reduced. [78]

In addition, other solutions are available for storing hydrogen as a liquid. This includes liquid ammonia and liquid organic hydrogen carriers (LOHC). However, these technologies are not considered in this thesis.

Solid-state Hydrogen

Hydrogen can form compounds with most elements in the periodic table. Hence, hydrogen can be stored by chemically bonding to other elements in a solid state. This is a way to increase the volumetric capacity compared to compressed and liquid hydrogen. The hydrogen can be stored in a porous metal by absorption or on the material's surface by adsorption. Large amounts of hydrogen can be stored without a significant increase in pressure. However, the high temperatures, high energy, and slow kinetics involved, are a problem for this storage method. Ongoing research tries to overcome these disadvantages, but this method of storage is not optimal so far. Commercial usage of these methods is unlikely to happen in the near future due to the current disadvantages. [73, 79]

3.8 Compressed Hydrogen

Compressed hydrogen is the most common and convenient way to store hydrogen. However, the low energy density of hydrogen could result in big storage vessels. As a result, the hydrogen is stored in high-pressure vessels. Compressed hydrogen is used for both stationary and mobile applications. Several efforts have been made to improve storage vessels for compressed hydrogen. This has resulted in different types of storage vessels. The different storage vessels are designed for different applications. As a result, the storage vessels have been divided into four classes.

In addition to storage in vessels, the concept of storing compressed hydrogen in salt caverns is gaining momentum in parts of Europe. This allows for storing vast amounts of hydrogen. In addition, low operating costs are required. Such enormous storage spaces can be necessary for the large-scale deployment of green hydrogen. However, this storage method is geographically restricted. [80]

3.8.1 Pressure Vessels for Compressed Hydrogen

Hydrogen storage vessels are divided into four different standard types: type I, type II, type III, and type IV. The pressure vessels are generally cylindrical. Type I are metallic pressure vessels. This type is the most conventional, the cheapest, and the heaviest. Type II are metallic pressure vessels with a composite overwrap. The metal and the composite share about the same amount of structural load. Type II vessels cost around 50% more than type I, but offers less weight. Type III consists of a full composite wrap with a metal liner. The composite material carries most of the structural load. The metal liner is primarily for sealing purposes. The weight is about half the weight of the Type II vessels, but their cost is doubled compared to Type II. Type IV is fully composite. This is a huge advantage when it comes to weight. This type is the lightest but also the most expensive. Figure 16 illustrates the composition of the different storage vessels. [73, 76]

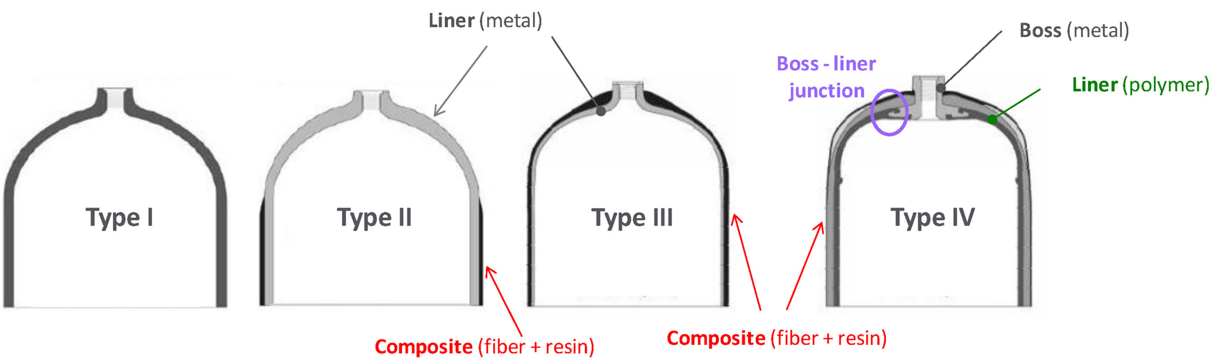

Figure 16: Illustration of the different compressed hydrogen storage vessels. [76]

Type I is reliable up to 500 bar. Type II can handle the highest pressures of the vessels and is not limited to a special pressure. Type III is reliable for pressures up to 450 bar. Type IV vessels can handle pressures up to 1000 bar. This is the cheapest type and they can handle the pressures necessary in most applications. As a result, type I vessels are suitable for most stationary applications where weight and space is irrelevant. This is a suitable option for applications where the hydrogen is stored at the production site. When the hydrogen needs to be transported, other vessels should be considered. According to Jørn Helge Dahl in Hexagon Purus, type IV vessels should be used in most cases which includes transport with trailer. The type IV vessels are easier to handle than the other vessels. In addition, the carrying capacity of the trailers is limited by the weight of the storage vessels. Type IV vessels offers the lowest weight. Hence, they are better suited for transport than the other options. [73, 76]

3.9 Transport

Delivery and transport are crucial aspects of the hydrogen infrastructure. For the end-user, it is the delivered hydrogen that provides value. As a result, the entire hydrogen value chain, from production to delivered product, needs to be considered to analyse competitiveness with other products. Which method is most cost-effective for transporting hydrogen depends on the transport distance and the amount of transported hydrogen. Today, hydrogen is primarily transported from the production site to the point of use via pipelines or on the road with trailers. [81, 82]

There are also ongoing projects on hydrogen transport by ships. For example, Kawasaki has already successfully transported liquid hydrogen by ship from Australia to Japan in a pilot project. Despite this, most projects are still in the experimental stage, and the ships are not ready for commercial use before the mid-2020s. These ships would be very costly. Hence, large amounts of hydrogen are needed before this is economical competitive with other transport options. [82–84]

Transporting hydrogen by pipeline can be done with new pipelines designed for this purpose or with approved, existing, pipelines. Hydrogen pipelines already exist in parts of the United States and some European countries. In addition, researchers are looking at the possibility of using natural gas pipeline infrastructure to distribute hydrogen. DNV GL has, on behalf of Gassco, analysed the opportunity to use existing natural gas pipelines to transport and export hydrogen from Norway to Europe. The conclusion was that this is possible, but technical aspects will limit the pipes from being fully utilised. Hydrogen embrittlement is one of the problems when using existing pipelines. On the other hand, pipelines have low operational costs and long lifetimes. As a result, transport trough pipelines can be a good option where pipeline infrastructure is available. However, in areas without this kind of infrastructure, transport with trailer is seen as the most convenient and most straightforward method today, especially for local distribution. [73, 82]

Transport by trailers is of great interest since this is the simplest method regarding infrastructure requirements. Gaseous hydrogen is compressed and transported in tube trailers. For transport purposes, the system weight is of great importance. Therefore, composite vessels are used instead of steel vessels. Theoretically, a single tube trailer can transport up to 1100 kg of compressed hydrogen at 500 bar. However, this amount is rarely achieved because of regulations that limit the allowable pressure, weight, and tube dimension that can be transported. These regulations come from the fact that there is a risk involved when handling hydrogen. In Norway, the handling of hydrogen is strictly regulated, like other hazardous substances, by The Norwegian Directorate for Civil Protection (DSB). [3, 41]

Although tube trailers are the most common method for transporting hydrogen today, it is a relatively costly option. Figure 17 illustrates the cost of distribution for both trucks and pipelines for different distances. As the distance increases, transport of compressed gas with tube trailers is less competitive than other transport methods. This is in line with findings from Greensight. Their findings show that transporting compressed hydrogen with trailers for over 2.5 hours is not cost-effective. This trend is also illustrated in appendix . [3, 85, 86]

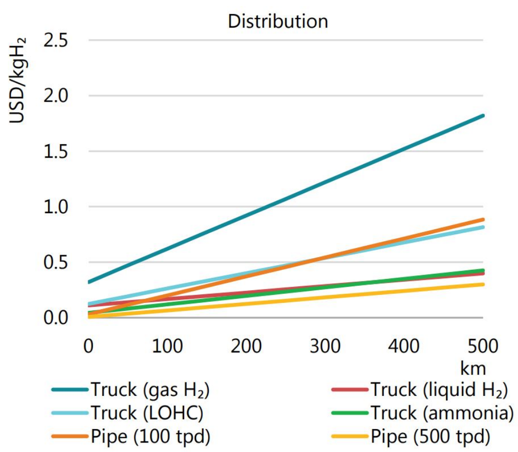

Figure 17: Estimated cost of hydrogen distribution for different distances from IEA. [3]

3.10 Hydrogen Safety

Hydrogen can be a solution to various energy challenges. However, increased use of hydrogen in new applications and areas entails new challenges. Hydrogen has been used for different purposes for a relatively long time, for example, in industry and aerospace applications. The knowledge and experience in the safe use of hydrogen are significant in these areas. However, hydrogen is now used in more applications and new areas. This happens in areas where there is little existing knowledge. In addition, hydrogen is closer to the population, which results in new challenges. Compared to industrial use, the handling of hydrogen in public spaces requires different safety requirements on design and procedures. At this stage, it is crucial to map out possible risks, as well as evaluate systems to mitigate potential high-risk incidents. [87, 88]

Hydrogen safety is essential for the widespread acceptance of hydrogen technologies [87]. In the following sections, issues related to hydrogen safety are presented. This includes the basic properties of hydrogen, accidents, codes, and standards.

3.10.1 Risks Related to Hydrogen Properties

Hydrogen has a high energy density, and like other energy carriers, hydrogen presents certain health and safety risks when used in a large scale. The risks related to hydrogen originate from its properties. [3]

As described in chapter 3.1, hydrogen is the lightest element in the periodic table. As a result, it is more likely to leak compared to other gaseous fuels. In open-air, this is positive regarding safety. The gas will quickly rise and dilute into harmless concentrations.

However, this property of hydrogen provides a safety threat when it is handled in enclosed spaces. [88]

Hydrogen is non-toxic, odourless, and colorless. Hence, it is undetectable by the human senses, which makes it difficult to detect leaks. Furthermore, the gas is highly flammable, and mixing with air can result in highly explosive mixtures. Hydrogen has a broad ignition range and a high flame velocity. In addition, compared to other flammable substances, low energy input is needed to ignite the gas. For example, hydrogen can be ignited by static discharge from equipment and by spontaneous combustion. These properties make it essential to avoid leaks and to keep the leaks as small as possible. [3, 41, 88]

There are also challenges related to whether it is in gas or liquid phase. For the liquid phase, the challenges are primarily related to low temperatures. This can cause damage to personnel handling the hydrogen. In addition, air will freeze if it comes into contact with liquid hydrogen or equipment at the same temperature as the liquid hydrogen. This will increase the concentration of oxygen and increase the risk of ignition. [41]

Embrittlement

Another problem is that hydrogen can cause hydrogen embrittlement. The term hydrogen embrittlement is used to describe the degradation of metals due to contact with hydrogen. Hydrogen atoms are absorbed by steel and other metals. This problem is a result of the small size of hydrogen. With enough time, the absorbed hydrogen forms bubbles at the metal grain boundaries. These bubbles exert pressure on the metal grains. If this pressure increases to high levels, the result is loss of ductility and reduced load-capability of the metal. Hydrogen embrittlement can result in cracking and increase the chance of failure. Although there are requirements for which steel materials can be used, systems that contain hydrogen must be maintained and inspected with a higher frequency than systems for petrol and diesel. [89, 90]

3.10.2 Risks and Incidents

As described in the previous section, hydrogen presents certain health and safety risks. Safety risks and incidents can be a challenge for the deployment of hydrogen. Especially if the risks are not well communicated and managed. Catastrophic failures in any hydrogen project could prevent widespread use and increase the public resistance towards hydrogen. There have been several accidents related to hydrogen with fatal consequences throughout history. However, implementing high-quality safety management and measures should allow hydrogen risks to be curtailed. [87, 91]

The potential risks of increased use of hydrogen must be thoroughly considered. Measures to prevent new incidents related to hydrogen safety include the correct design of equipment, correct choice of material, and maintenance to prevent leakage. In addition, it is important to secure the surrounding area. This can include selecting electrical and mechanical equipment that can prevent hydrogen from piling up after leakage and prevent ignition of the hydrogen. Furthermore, other protective measures can be completed, such as explosion venting and the implementation of safety distances. [92]

3.10.3 Codes and Standards

In Norway, DSB are responsible for handling and transporting hazardous substances. The overall task of DSB are to maintain an overview of risks and vulnerabilities. This also includes emergency planning, fire safety, electrical safety, and consumer and product safety. [93]

In Norway, the handling of hydrogen is governed by the *Regulations relating to the Handling of Hazardous Substances*. These regulations also govern hydrogen bunkering. Furthermore, the operation of hydrogen plants is governed by the regulations relating to health and safety in potentially explosive atmospheres and the regulations relating to pressure equipment. In addition, transporting hydrogen must comply with the requirements in the *Regulations relating to the Transport of Dangerous Goods by Road*. [41]

Existing regulations and standards currently limit the increased use of hydrogen. They will not allow full exploitation of the benefits hydrogen can provide. A safe introduction of hydrogen into the society requires further work on establishing reasonable regulations, guidelines, and standards for the use of hydrogen. This can fulfill the potential of hydrogen utilisation. [3]

4 Fuel Cell Fundamentals

The chemical energy in hydrogen can be converted to electric energy with fuel cell technology. In this chapter, the fundamentals of the fuel cell and an overview of different fuel cell technologies will be introduced. Finally, an overview of fuel cell systems for stationary applications will be provided.

4.1 Principles of Operation

The fuel cell can described as a factory that takes fuel as an input and produce electricity as output. The fuel cell uses hydrogen or hydrogen-based fuel and can, by definition, be fed continuously with fuel to maintain electrical power output indefinitely. The fuel cell operation shares similarities with both the battery and the conventional combustion engine. Both the battery and the fuel cell operations are based on electrochemical reactions to convert chemical energy into electrical energy. [94, 95]

The fuel cell will only operate when supplied with fuel and can not be charged and discharged. This means it will not degrade over time in the same fashion as a battery would. Considering this, the operation of the fuel cell is perhaps more similar to the combustion engine. The combustion engine also converts chemical energy into mechanical or electrical energy. However, the combustion engine first needs to convert chemical energy into heat. Therefore, the fuel cell is often more efficient than the combustion engine. The fuel cell combines many advantages of battery and combustion engine technologies by the characteristics described above. The comparison of the different technologies is shown in figure 18. [94, 95]

As introduced, the fuel cell converts hydrogen or hydrogen-based fuels directly into electricity and heat through the electrochemical reaction of hydrogen and oxygen. The electrochemical reaction is shown in equation 18. [61]

$$2H_2 + O_2 \longrightarrow 2H_2O + energy \tag{18}$$

The reaction is the reverse of the electrolysis reaction of water. Hydrogen is the fuel in the fuel cell reaction, and the oxidant is oxygen. The chemical energy in the fuel and the oxidant is converted into electricity, heat, and water. This simple reaction is the basis behind the fuel cell operation. Although the overall reaction is the same, the ion transfer and the sub-reactions occurring at the anode and cathode may differ slightly between fuel cell types. The system provides current via an external electrical circuit with a DC load, which, in standard conditions, provides an ideal electromagnetic force of 1.23 V. [61, 94, 96]

The electrical efficiency of a fuel cell system is presented in equation 19. The fuel cell's electrical efficiency compares the net electrical output to the HHV fuel consumption of the system.

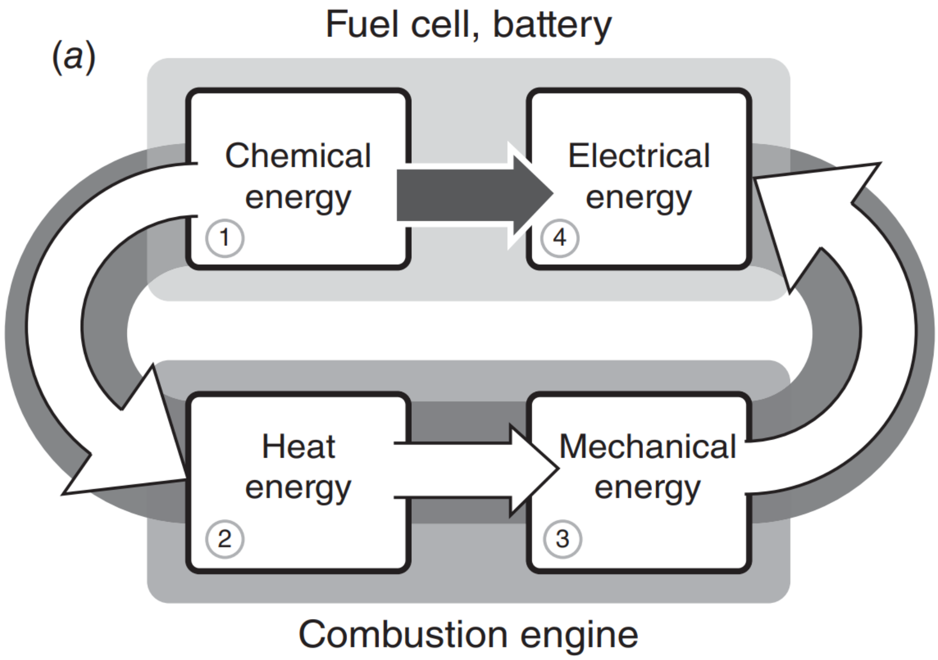

Figure 18: Comparison between a fuel cell, battery and combustion engine. Both the fuel cell and the battery produce electricity through a electrochemical reaction, whereas the combustion engine converts chemical energy into heat before further convertion into mechanical energy and electricity. [95]

$$\eta_{el_{(HHV)}} = \frac{Electric\ Energy\ Output}{Energy\ Input_{(HHV)}} \tag{19}$$

In equation 19, η_{el} is the electrical efficiency. This correlation will determine energy demand and hydrogen demand in the chapters to come.

4.2 Cell Components

In order to understand the fundamental operation of a fuel cell, it is important to have some knowledge about the different components. The different fuel cell types are built in a very similar manner. However, the materials used in the components differ highly based on the specific fuel cell types. [94]

In this study, the Polymer Electrolyte Fuel cell (PEMFC) is the fuel cell that will be used for the application, and for this reason, the PEMFC is chosen to describe the component elements in a little more detail. Figure 19 below shows a simple schematic of a PEMFC in operation.

The different components of the fuel cell is also presented in figure 19.

4.2.1 Flow Field Plate

The fuel cell is, as mentioned before, dependent on a constant supply of fuel to operate. When a fuel cell is operating at a high current, its demand for reactants is high too.

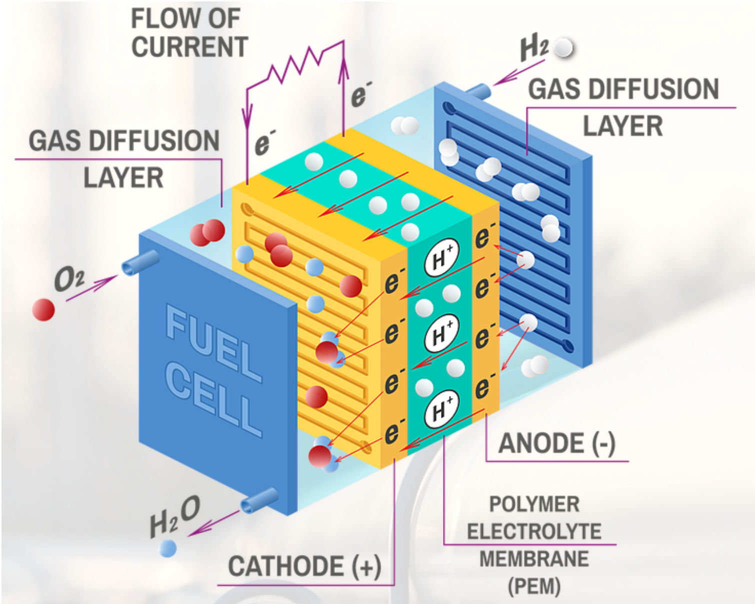

Figure 19: Schematic of operation of a PEMFC. [97]

An efficient supply of reactants is required, which is accomplished by using flow field plates in combination with porous electrode structures. The flow field plate contains several channels or grooves to distribute the reactant gasses over the surface of the fuel cell efficiently. The shape, size, and pattern of the flow field plate affect the performance of the fuel cell. The flow field plates are also important for water management and are designed to remove excess water. The fuel cell is most efficient at a certain humidity level, but too much water will worsen the operation. The flow field plates are illustrated as the blue endplates in figure 19. [95]

4.2.2 Membrane Electrode Assembly

The PEMFC is named after its electrolyte material, called a polymer electrolyte membrane. The role of the polymer electrolyte membrane is to transfer H^+ ions from the anode to the cathode. The PEM also prevents the transfer of electrons through the membrane. The electrons flow through an external circuit instead. In PEMFC, a porous catalyst electrode is bonded onto each electrolyte side. This anode - electrolyte - cathode assembly is called *Membrane Electrode Assembly* and is very thin, often less than 1 mm. These MEAs are connected in series, usually by using bipolar plates. The polymer membrane must be hydrated with liquid water to maintain the conductivity, which means the PEMFC is limited to operate at around 90 °C or lower. [61, 87]

Several different manufacturers produce PEMs. However, the industry standard is to use a material called Nafion. Nafion is a fluoroethylene and has high chemical resistivity and mechanical strength, allowing for very thin films. Nafion and other similar chemical compounds can also absorb large quantities of water, and whilst well hydrated, the H^+ ions can move freely within the material. This makes the material a good proton conductor. [61, 87]

The catalyst material for both the anode and the cathode is platinum, as for the PEM electrolysis. Currently, platinum-based materials are the only suitable catalysts due to the acidic environment and low operation temperatures. The catalyst layer is formed of tiny particles of platinum on a surface of fine carbon powders. The platinum is well spread out to make the contact surface area as big as possible for the reactants. The carbon helps with the conductivity of the electrons to the external circuit. The carbon-supported catalyst particles are joined to the electrolyte on one side and the gas diffusion layer on the other side. [87, 95]

Usually, the catalyst layer is reinforced by a thicker porous layer. Carbon paper or carbon cloth is often used to provide the mechanical structure of the electrode. The gas diffusion layer protects the catalyst structure and enhances electrical conductivity. The porous layer also diffuses the gas onto the catalyst layer and is called the gas diffusion layer (GDL). The GDL is also important for water management, especially the removal of liquid water from the fuel cell. [87, 95]

4.2.3 Bipolar Plates

The voltage of one single fuel cell is limited to about 1 V, and under load, the output voltage often falls to around 0.6-0.7 V. This range corresponds to an operational average when the fuel cell operates at a reasonable electrical efficiency of around 45%. At this point, the power density is near the maximum. However, this amount of output voltage is not even close to the amounts needed for real-world applications. For this reason, fuel cell stacking is needed. [87, 95]

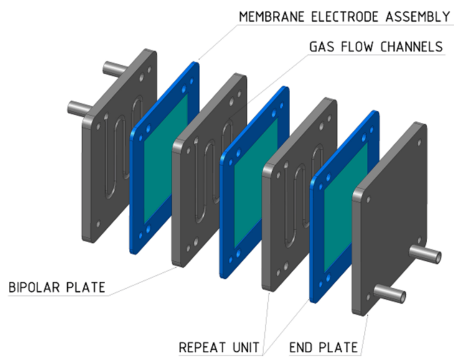

Figure 20: Three cells stacked using bipolar plates. The anode of one cell is connected to cathode of the neighbour cell. [98]

By interconnecting fuel cells in series, any voltage requirements can be met. The most common forms of fuel cell stacking are vertical or bipolar stacking. In this interconnecting series configuration, a single flow plate structure is in contact with both the fuel electrode of one cell and the oxidant electrode of another cell. In other words, the plate serves as both the anode in one cell and the cathode in the other, hence the name bipolar. Most bipolar plates used in PEMFC stacks are made of graphite. The reason is high electrical conductivity and light weight, meaning competitive power density. [87, 95]

4.3 Fuel Cell Performance and Losses

The performance of a fuel cell can be evaluated by studying the characteristics of its voltage-current density graph. The voltage-current density graph, also called the V-i graph, shows the output voltage from a given current density output for a fuel cell. The V-i graph of a PEMFC is shown in figure 21. [95]

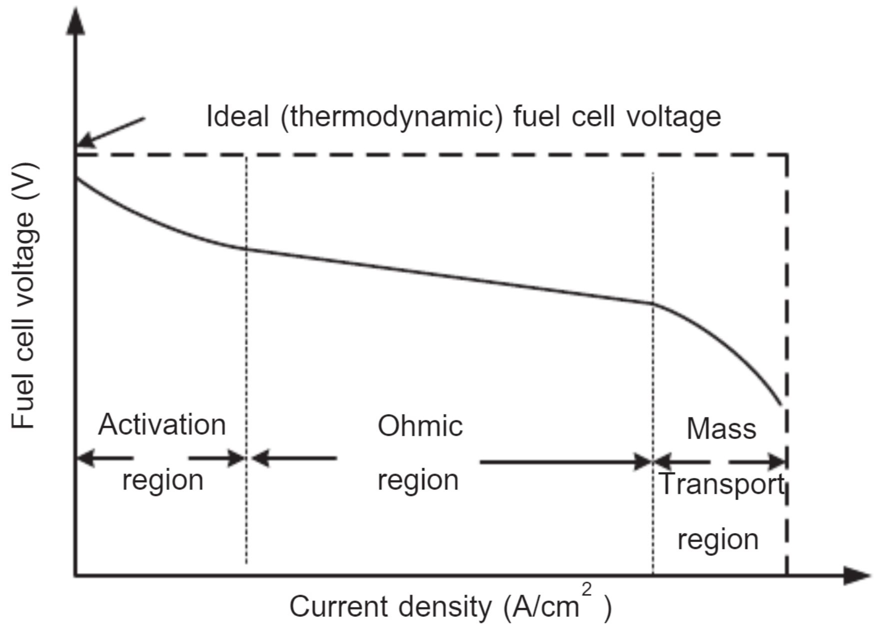

Figure 21: V-i curve of a PEMFC. As a result of unavoidable losses, the fuel cell output voltage is lower than the thermodynamically ideal output voltage presented as the dashed line in the figure. [99]

When continuously supplied with fuel, an ideal fuel cell would deliver any amount of current while maintaining a constant voltage defined by the thermodynamic voltage potential. In practice, however, the voltage of an operating fuel cell would never reach this potential due to unavoidable losses, as illustrated in figure 21. In addition, the output voltage of the fuel cell drops as the current increases. It limits the total power output that can be delivered, as power is the product of current and voltage. Maintaining high fuel cell voltage under high current loads is critical for further implementing fuel cell technology. [95]

There are three losses that cause fuel cell voltages to drop, illustrated in the V-i curve. These losses are:

1. Activation losses (caused by the electrochemical reaction)
2. Ohmic losses (caused by the conduction of ions and electrons)
3. Concentration losses (caused by mass transport of reactants)

4.3.1 Activation Losses

Activation losses are caused by the electrochemical reaction in which reactants are converted into products. The transition from reactants to products depends on the reactants being in activated state. In order for the reaction to take place, there is need for a small amount energy often referred to as activation energy. The activation losses are caused by the slowness of the reaction taking place on the electrode surfaces. In order to increase the speed of this reaction and lower the activation barrier, a part of the fuel cell voltage is consumed. Changing the cell voltage also changes the free energy of the reaction, as charge species are sensitive to voltage. Thus affecting the size of the activation barrier. This activation voltage is often referred to as activation overvoltage, or simply η_{act}. Equation 20 expresses η_{act}, this is called the Butler-Volmer equation. [51, 95, 100]

$$\eta_{act} = -\frac{RT}{\alpha zF} ln j_0 + \frac{RT}{\alpha zF} ln j \tag{20}$$

In equation 20 α is the transfer coefficient, z is the amount of exchanged electrons, j is the net current density, and j_0 represents the rate of exchange between the reactant and product states at equilibrium. As current is applied to the cell, the anodic current becomes larger than the cathodic current, moving away from the equilibrium current density. The Butler-Volmer equation describes how this increase in net current density creates a kind of friction in the cell, as electrons exchanges faster than the equilibrium exchange rate, j_0. The further the net current density, j, increases beyond the equilibrium rate, j_0, the more friction builds up. [51, 87, 95]

The Butler-Volmer equation states that the current produced by the electrochemical reaction increases exponentially with the activation overvoltage. Thus, as the equation 20 shows, increasing the current density of a fuel cell pays a price of also increasing activation voltage losses. Hence, in order to minimise the activation losses, it is critical to improve the reaction kinetics by increasing j_0. [51, 87, 95]

The Butler-Volmer equation is highly precise when evaluating low net current densities. However, for electrochemical engineering technologies, like a fuel cell, the current densities and overpotentials are often so large that a simplified approximation becomes more relevant. Simplified, equation 20 can be expressed as what is called the Tafel equation, shown in equation 21. For the Tafel equation, the coefficients a and b are often tabulated. [51]

$$\eta_T = a + b log j \tag{21}$$

The Tafel equation is a linearised version of the Butler-Volmer equation, which can be derived for large positive overpotentials. For fuel cells, the primary interest is for large amounts of produced net current, meaning larger values of overpotential. For low- and medium-temperature fuel cells, activation overpotential causes the most significant irreversible voltage drops and occurs mostly on the cathode. At higher operating temperature fuel cells, the overpotential losses become less important. [95, 100]

4.3.2 Ohmic Losses

The ohmic losses represent the linear part of the V-i curve in figure 21. Resistance scales with the area, making it necessary to use an area-specific resistance (ASR) when discussing ohmic losses in a fuel cell. The ASR is a measure that accounts for the resistance scaling with the area, making it possible to compare different fuel cell sizes. The ASR is given as the area multiplied by the ohmic resistance. [87, 95]

The ohmic losses for a fuel cell can be expressed as follows:

$$\eta_\Omega = j \cdot ASR_\Omega \tag{22}$$

In equation 22, ASR is the area-specific resistance, j is the current density, and η_{ohmic} is the ohmic losses. The resistance scales not only with the cross-sectional area of the conductor but also with the length of the conductor. Therefore, the Area-specific resistance can be expressed as shown in equation 23. [87, 95]

$$ASR_\Omega = \frac{L}{\sigma} \tag{23}$$

As equation 23 indicates, where L is the length and σ the conductivity, the shorter the length of the conductor, the lower the ASR. Hence, one of the ways to decrease the effects of ohmic overpotential is by making the electrodes in the fuel cell as thin as possible. Another way to decrease ohmic overpotential is by making the electrodes as conductive as possible. As discussed earlier, Nafion is used for this purpose for the PEMFC. [87, 95]

4.3.3 Concentration Losses

Finally, some losses are caused by the mass transport of reactants and products. These losses are often called concentration losses and are consequences of insufficient supply or removal of reactants and products. Reactant depletion or accumulation in the catalyst layer leads to fuel cell performance losses. The concentration performance loss,$\eta_{conc.}$ can be described from the following equation. [87, 95]

$$\eta_{conc.} = c \cdot ln(\frac{j_L}{j_L - j}) \tag{24}$$

In equation 24, j_L refers to the limiting current density occurring when the concentration of reactants in the catalyst layer of the fuel cell drops to zero. The coefficient c is a constant dependent on the geometry and mass transport of the fuel cell. [87, 95]

Concentration losses are highly dependent on the geometry of the flow field plates. One way of minimising the losses is to design the patterns of the bipolar plates carefully. Research has found that parallel or serpentine-designed flow field plates are preferred because they provide a good balance between pressure drop and water management abilities. Pressure drop is required to lead the gas through the channels, and water management prevents flooding and drying out of the cell. [87, 95]

4.3.4 Thermodynamic Work Potential of a Cell

At the beginning of this chapter, the fuel cell was introduced as a conversion engine, converting chemical energy into electrical energy. Thermodynamics decides the bound limits for energy conversion, and thermodynamic principles are crucial to understanding this technology. The fuel cell operation goal is to extract the internal energy in hydrogen and convert it into electrical energy. [95]

The fuel cell thermodynamics are generally very similar to the thermodynamics of water electrolysis, except for the direction of the reactions. The water electrolysis thermodynamics are presented in chapter 3.4. [51]

Considering the irreversible losses, the voltage of the fuel cell can be expressed as shown in the equation 25 below. [95]

$$E_{cell} = E_{rev} - \eta_{act} - \eta_{ohmic} - \eta_{conc.} \tag{25}$$

where E_{cell} is the voltage of the cell, E^{rev} the thermodynamic reversible voltage potential, η_{act} the activation losses, η_{ohmic} the ohmic losses, and $\eta_{conc.}$ the concentration losses. [95]

Equation 25 shows that the cell voltage is dependent on the reversible thermodynamic voltage and the irreversible losses. [95]

As shown in the V-i curve, figure 21, the initial losses are caused by the activation losses. The ohmic losses represent the middle section of the curve, and the concentration losses are represented in the tail end of the curve. [95]

As previously mentioned, the voltage drop will affect the power output delivered as the current increases. This correlation is well described in figure 22 below, where the power curve is presented alongside the V-i curve for the fuel cell. [95]

The power curve in figure 22, illustrates that as the fuel cell current density increases, the power also increases until a point of maximum power is reached. From this point onwards, the power output decreases although the current density increases. For this reason, fuel cells are designed to operate around the point of maximum power output. [95]

4.4 Different Types of Fuel Cells

The following sections present the different types of fuel cells relevant to this thesis. The technology of focus will primarily be the PEMFC, but the other technologies will also be mentioned.

Fuel cells are often classified according to several operating features, depending on the electrolyte composition, type of fuel, or, most often, operating temperature. [94]

- Low temperature fuel cells operate at temperatures between 20-100 °C
- Medium temperature fuel cells operate between 200-300 °C
- High temperature fuel cells operate between 600-1500 °C

For this reason, the different types of fuel cells have varied areas of usage, considering the temperature differences. [94]

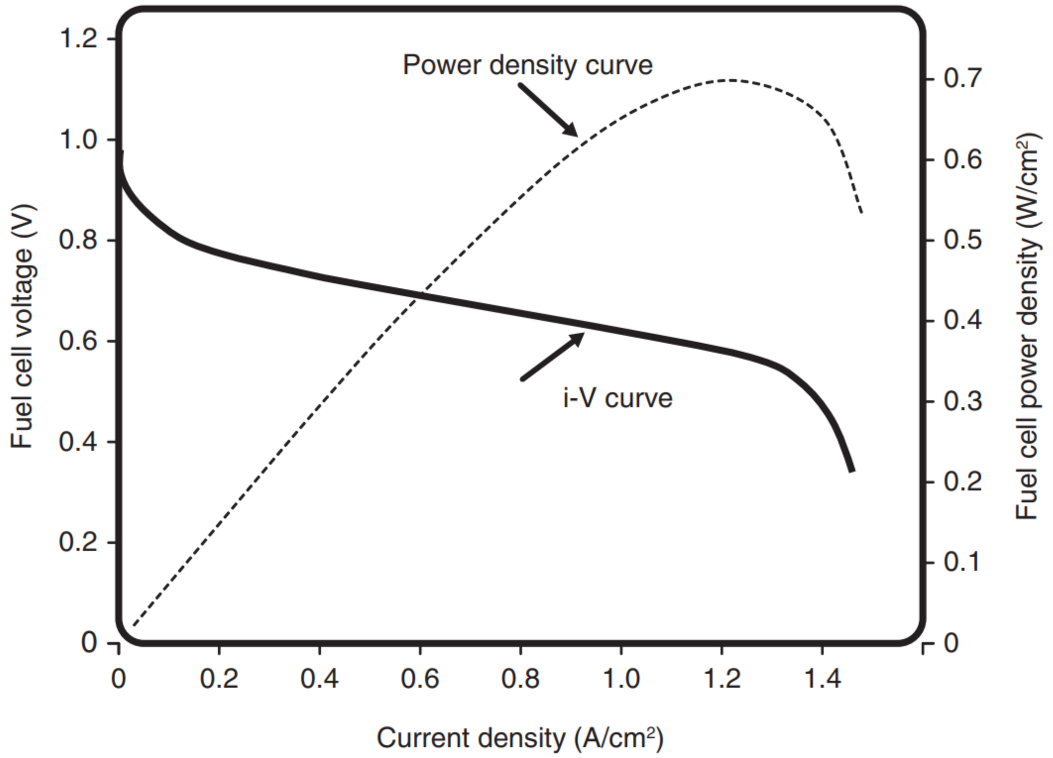

Figure 22: The power curve of the fuel cell, plotted alongside the V-i curve. The power curve is the resulting curve of multiplying the current density with the output voltage in each point of the V-i curve. [95]

An overview of the six most common fuel cells today is shown in figure 23. The figure also presents the different operating temperatures of the fuel cells, the electrolytes, and the different conversion reactions. [94]

Polymer Electrolyte Membrane Fuel Cell

The main focus of fuel cell technology in this thesis is the PEMFC. The PEMFC cell composition has been introduced in more detail earlier, in section 4.2. The PEMFC is a low-temperature fuel cell and operates between 50-100 °C. Because of the low operating temperature, the PEMFC is an attractive option for a wide range of applications. PEMFCs are used in transportation, stationary power production, and mobile systems. The automotive industry is a large investor in PEMFC development and has been for some time. This has made the PEMFC one of the most mature fuel cell technologies, and is why this specific fuel cell is chosen for further reference. [87]

Solid Oxide Fuel Cell

The solid oxide fuel cell (SOFC) is similar to the SOEC technology. The SOFC operates at temperatures between 500-1000 °C, making it a high-temperature fuel cell. An advantage of the SOFC is that it can run on almost any hydrocarbon fuel in addition to hydrogen. Hydrocarbons, for example, natural gas, need to be reformed either through internal or

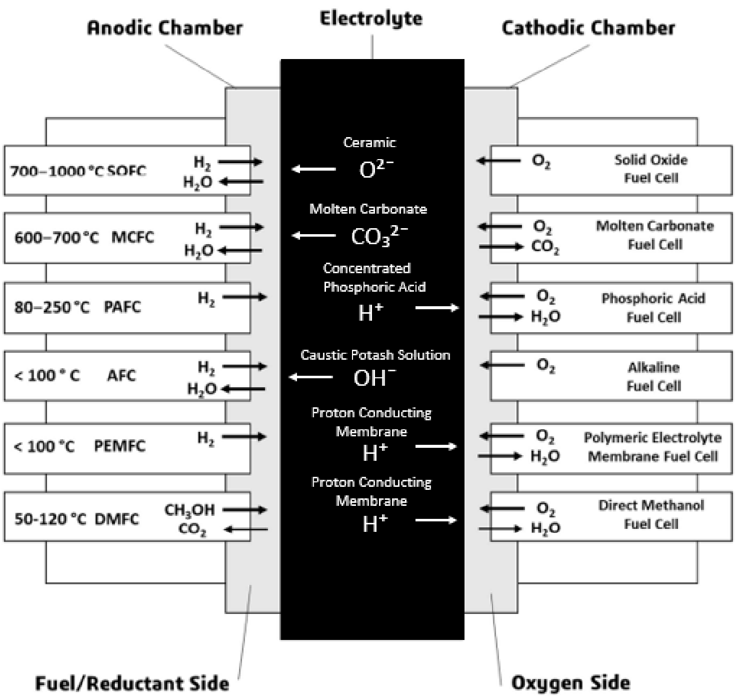

Figure 23: The six most common fuel cell technologies today. Modified from [101].

external prereforming. This reforming reaction is highly endothermic and requires heat. The heat generated and later released from the operation of the SOFC is high-quality energy that can be useful for other applications. For this reason, the SOFC is very promising for combined heat and power generation. [51, 94]

Alkaline Fuel Cell

The alkaline fuel cell (AFC) is a mature technology that has been around for a very long time. The advantage of the alkaline fuel cell is that it is similar to the alkaline electrolysis in which nickel and nickel oxide can be used as electrodes. These electrodes are cheaper and more durable compared to platinum. In addition, many catalysts can be used in this fuel cell, which provides flexibility. The limitation of the AFC is the possibility of forming solidified alkaline carbonates if carbon dioxide enters the electrolyte. The AFC is typically operated using pure oxygen and pure hydrogen to prevent carbonate formation, which makes it suited for stationary power supply. [51, 94]

Direct Methanol Fuel Cell

The direct methanol fuel cell (DMFC) is quite similar to the PEMFC. The two main differences are that on the anode side in the DMFC, hydrogen gas is replaced with a liquid solution of water and methanol. The catalyst is a combination of platinum and ruthenium. The reason for adding the ruthenium is to prevent carbon monoxide poisoning, which otherwise can lead to blocking of the catalyst. DMFCs are steady and reliable. However, the power output is lower than for other fuel cells. [51]

Molten Carbonate Fuel Cell

The molten carbonate fuel cell (MCFC) is one of the high-temperature fuel cells and operates at around 600 °C. The MCFC electrolyte is usually a composition of alkali-carbonates retained in a ceramic matrix. At high operation temperatures, the alkali-carbonate forms molten salt with high conductivity provided by carbonate ions. This operation has a high reaction rate, removing the need for noble metal catalysts. In addition, the high temperatures allow great fuel flexibility and high valued heat output. For this reason, the MCFC is most often used for combined heat and power applications and can reach a combined efficiency of up to 90%. [51, 87]

Phosforic Acid Fuel Cell

The phosphoric acid fuel cell (PAFC) operates at temperatures around 200 °C. However, in functionality, it is pretty similar to the PEMFC. The PAFC uses a solid acid carrier membrane composed of silicon carbide particles. The main advantage of the PAFC is that it is not sensitive to carbon monoxide poisoning. In addition, the electrolyte has been reported capable of operating for 40 000 hours without significant electrolyte losses. The drawbacks of the technology are the low power density and problems regarding the acid carrier membrane. Due to the relatively high temperatures, this technology is often best suited for stationary applications. [51]

4.5 Stationary Applications

Due to the feature of fuel cell modules being assembled in stacks, the fuel cell technology can reach power output ranges from a couple of watts to several MWs. Consequently, fuel cell technology can be used in several applications, both in mobile and stationary systems. The most common use areas for stationary applications are primary power generation, grid stabilisation, backup power systems, and combined-heat-and-power production. An advantage of fuel cell systems is the feature of working off-grid and delivering power supply to remote areas. The main employment sectors for stationary applications have been micro-CHP, large stationary applications, uninterruptible power systems, and integrated power systems. These stationary applications highly depend on the power demand from the load, making the fuel cell systems vary a lot in size. The stationary fuel cell market ranges from a few kW backup power systems to multiple MW primary power applications. In addition, the fuel cell design parameters, fuel type, and supply for stationary fuel cell systems differ for the different fuel cell technologies. The range of power of the most common fuel cell types is shown in figure 24. [87, 96]

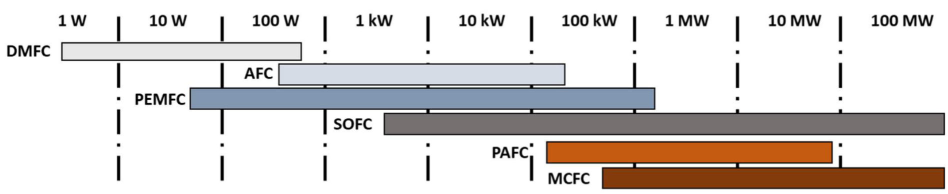

Figure 24: Range of power for different fuel cell types. [96]

As figure 24 shows, the different fuel cell technologies have a wide range of power. The high-temperature fuel cells such as SOFC, PAFC, and MCFC can reach power outputs up to many MWs due to the operating temperature. The disadvantages of high-temperature fuel cell operation are start-up and shutdown characteristics. This is currently close to four hours for a ramp-up of 0-100%. The figure also shows that the low-temperature fuel cells deliver lower power outputs, which means they often are suitable in portable and autonomous applications. [96]

In this project, the PEMFC will be the studied technology for use in larger stationary power applications. As figure 24 shows, the PEMFC is suitable for power applications up to around a 1 MW power range. One of the advantages of the PEMFCs for stationary applications is that the low operation temperature allows for quick start-ups and better durability. This also allows for the possibility of turning on and off the fuel cell system multiple times a day and for the system to be set in standby mode. The downside to the PEMFC is that platinum is needed to split hydrogen and electrons at this temperature, as mentioned briefly in chapter 4.2. Finally, platinum can also be poisoned by carbon monoxide, limiting the fuel flexibility only to cover pure hydrogen. [102, 103]

Backup Power Generation

Backup power generation from fuel cells is suggested as a near-term step to gain stationary fuel cell experience. Backup power solutions today are primarily diesel generator sets. The technological change from diesel generators to hydrogen fuel cell systems for backup power would reduce air and noise pollution. As mentioned earlier, the fuel cell capacities come in a range of sizes and have been coupled into the MW range. In comparison, diesel generator capacity range from 2.5 to 3 MW for backup power solutions. [104, 105]

Data centers are examples of industries highly dependent on backup power supply. Hence the applicability of fuel cell systems to data centers has been studied a bit. An advantage of integrating fuel cell systems for backup power for data centers, is that a redesign of the data center is not necessary. The fuel cell system would acquire the same electrical infrastructure, redundancies, and support systems as the diesel generator. In addition, a fuel cell system would provide robust durability and fast startup times. An estimated 45% of data centers could be provided with hydrogen backup power solutions by 2030. Further estimates suggests that by 2050 this share could be around 65%. The use of hydrogen for this purpose could represent a relatively low demand for hydrogen, as outages and downtime of data centers occur infrequently and generally last for a short period. [104, 105]

Prime Power Generation

Several types of fuel cells are applicable in power generation for larger stationary systems. Currently, AFC, PEMFC, SOFC, MCFC and PAFC have been used worldwide for electricity generation for local use [94]. For prime power generation up to 1 MW, fuel cells can be operated in power-driven or load-following mode. Increasing development achieve efficiencies around 50%, or more. Larger fuel cell systems can be used to replace the electricity grid for on-site premium power generation at critical loads or large energy-consuming facilities. Fuel cells can provide high-quality, grid-independent power for on-site facilities in these applications. Excess heat from the fuel cell operation can also be utilised for higher energy efficiency, for example, to heat buildings or facilities. [96, 103, 106]

Fuel cells are also compatible with renewable energy production sources to create flexible energy systems. In addition, fuel cells provide reliability and can be used to solve intermittency problems on the grid. This will be the main focus area of this study. [107]

CHP Generation

Combined-heat-and-power (CHP) generation is suitable for fuel cell technology, as both heat and electricity are produced from only one fuel source when in operation. Therefore, utilising the electricity and the heat generated offers an increased combined efficiency compared to only the electric efficiency. PEMFC and SOFC are currently used for lower energy supply for smaller residential applications. SOFC, PAFC, and MCFC are used for larger commercial and industrial CHP applications. In Europe, more than 4100 fuel cell units for CHP applications have been installed. [94, 96]

5 Economic Analyses

The cost of energy production is perhaps the single most essential factor in determining whether an energy technology will become commercially competitive. In order to compare different energy technologies, a standard called levelised cost, has been developed. The levelised cost standard takes into consideration the different costs of installing and running a facility, as well as the delivered output, either as electricity- or mass- production. [108]

The two forms of levelised costs used in this project are LCOH and LCOE.

5.1 Levelised Cost of Hydrogen

In order to evaluate the cost competitiveness of hydrogen, the cost of green hydrogen production is important. The LCOH is the ratio of the total discounted lifetime cost of a hydrogen production plant to the total amount of hydrogen to be produced during the lifetime. Both terms are expressed as net present value. Net present value considers the present value of cash inflows and outflows over a period of time. The NPV relies on the discount rate. The discount rate refers to the interest rates used to determine the present value of a future cash flow. The discount rate expresses the value of money depending on time and can be used to estimate whether a planned project will be financially viable or not. [109–112]

The LCOH formula is presented in equation 26 and is presented as a cost per kilogram production. The expenses are divided into two groups, namely capital expenditures (CAPEX) and operational expenditures (OPEX). CAPEXes are expenses regarding investments by a company to acquire or upgrade physical non-consumable assets such as buildings, property, or technology. OPEX are the costs of the company to run the day-to-day operation, such as electricity costs. CAPEXes are paid upfront, while OPEXes are running costs paid periodically. [109, 110]

$$LCOH = \frac{CAPEX + \sum_{k=1}^{n} \frac{OPEX}{(1+r)^k}}{\sum_{k=1}^{n} \frac{m_H}{(1+r)^k}} \tag{26}$$

In equation 26, n is the economical lifetime of the facility in years, r is the discount rate, and m_H is the amount of produced hydrogen gas in kilogram. For levelised costs, the discount rate acts as the rate at which production and costs are discounted given over time. [110, 112]

5.2 Levelised Cost of Electricity

The levelised cost of electricity is similar to the LCOH. The LCOE accounts for the costs and the generated electricity throughout the lifetime. The LCOE formula is presented in equation 27. [108]

$$LCOE = \frac{CAPEX + \sum_{k=1}^{n} \frac{OPEX}{(1+r)^k}}{\sum_{k=1}^{n} \frac{e_H}{(1+r)^k}} \tag{27}$$

Similarily to the LCOH, the formula consists of CAPEX and OPEX, the economical lifetime n, and the discount rate r. In comparison, the LCOE considers the generation of electricity, e_H, instead of the mass production of hydrogen, m_H. Discount rates also affect the LCOE, similarly to the LCOH. [108]

5.3 Sensitivity Analysis

Sensitivity analyses determine how various variables in a mathematical model contribute to uncertainty. The sensitivity analysis is also referred to as a simulation analysis, as changing one independent variable to different values will affect the target variable in the mathematical model. In other words, by creating a given set of variables, namely input variables and target variables, an analyst can determine how changes in one variable affect the total outcome. This analysis is used in economics and is known as a what-if analysis to cover uncertainty aspects. It is an effective method to identify where improvements can be made. [113]

6 Methodology

This chapter presents the methodology used to produce the results of this bachelor thesis. The assumptions used, as well as the strengths and weaknesses of the methodology, will be pointed out in order to enhance the credibility of the results.

As introduced in chapter 1, the scope of the thesis is to evaluate if a hydrogen solution can be technologically and economically feasible compared to expensive upgrades of grid infrastructure. Tensio and NTE have together provided a case where there is planned an industrial expansion, which will result in power demands exceeding the current capacity of the grid. This requires upgrading the grid infrastructure or finding other solutions to meet the future power demand. Hydrogen can work as such a solution. This lays the foundation for further work with this project. In order to find out whether the hydrogen solution is competitive with the grid solution or not, several aspects have to be considered.

Firstly, it is important to find out how the system will operate in order to choose suitable equipment and components. This is related to the local demand at the industrial site and the amount of hydrogen available from the production site. The industrial site of which the fuel cell system will be implemented is analysed and presented in the first section. Calculations and visual representation of the energy demand at the industrial site are conducted using MATLAB.

Moreover, the methods used for collecting all the data related to the components will be presented. The relevant technologies are presented in chapters 2-4, while the methodology for choosing components is presented in this chapter. First, an overview of the technical data for the different components will be provided. Secondly, an overview of the cost data related to all the components will be made. The collected data is used to calculate a LCOH and LCOE using Excel. The LCOH will cover the production and distribution of hydrogen and be the basis for further conducting a LCOE. This LCOE will be used to estimate a total cost for the hydrogen solution, which is to be compared to the cost of upgrading grid infrastructure.

Finally, the competitiveness of the hydrogen solution will be discussed. In evaluating competitiveness, the hydrogen solution will be compared to the To evaluate the competitiveness of the hydrogen solution, the hydrogen solution is compared to the grid upgrade solution based on economics and operational features. In addition, a fuel cell system will be compared to a diesel genset, in order to evaluate the competitiveness compared to other technologies. The comparison to the diesel genset is based on the LCOE of the fuel cell system and the LCOE of the diesel genset.

To get an overview of the approach used to find the results, the different steps are summarised in figure 25.

The figure shows the different steps of the methodology and the study's objectives. Most of the information is found in the literature review. Some information is obtained from different manufacturers in the market. As a result of competition between market participants, some essential data is not available. This has required the need for some assump-

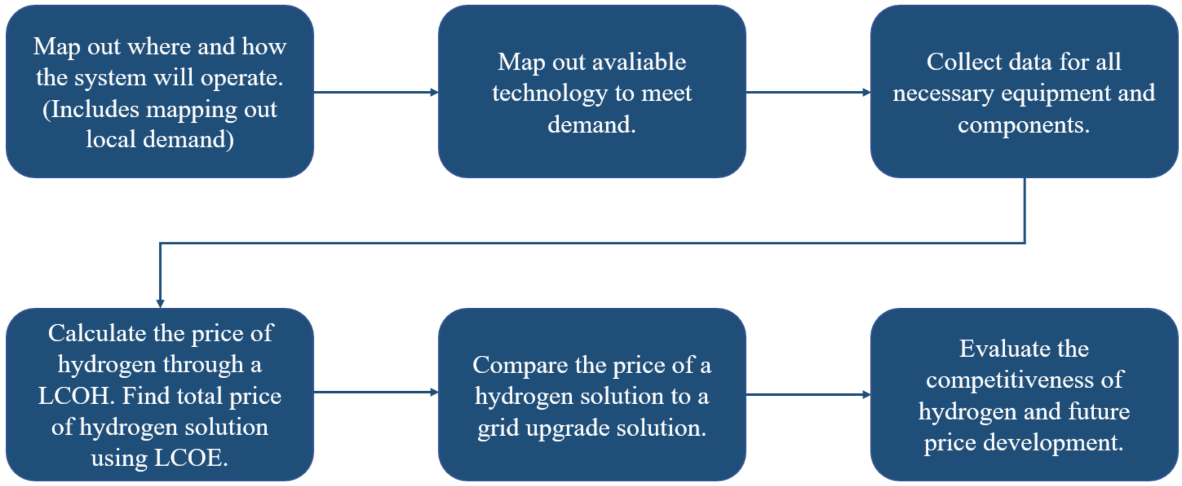

Figure 25: Overview of the approach used to find the results for this thesis.

tions. These assumptions are expected to affect the results somewhat but are attempted to be kept to a minimum.

The hydrogen production site used in the analysis will be Meraker Hydrogen AS, and the prerequisites concerning power demand and location of interest is provided by NTE and Tensio.

Meraker Hydrogen AS

Meraker Hydrogen AS is a company that was established in 2020. The company aims to produce green hydrogen in Meråker municipality in Trøndelag. In Meråker, there is access to locally produced hydropower and large volumes of water needed in hydrogen production. In addition, the company has a regulated industrial area with a safe distance to other buildings and other businesses. This is where the production plant is planned to be located. Hydrogen production is assumed to start in early 2024.

Meraker Hydrogen AS intends to build a plant that can produce up to 10 tonnes of hydrogen per day. This corresponds to 23 MW of installed electrolyzer capacity, which will exclusively be based on local sources of renewable energy. The production site is near the railway and European route E14. This makes it possible to distribute the hydrogen in an efficient way. This thesis will only consider a small part of this production volume. The electrolyser evaluated will have an installed capacity of 1.25 MW and produce 500 kg hydrogen per day.

NTE and Tensio

NTE are a renewable energy company from Trøndelag county. The company was first established in 1919 and is today owned by 19 municipalities in Trøndelag. For over 100 years, they have developed, produced, and distributed green and renewable energy. They have also built and operated digital infrastructures all over Norway. However, their primary focus is on Trøndelag.They are one of the key stakeholders in Meraker Hydrogen

AS, as they consider hydrogen an important energy carrier in the future energy mix. [114]

Tensio are Norway's second largest power grid company and is responsible for supplying 250 000 customers throughout Trøndelag with electricity. The power grid company started up in November 2019, when NTE Nett and TrønderEnergi Nett merged and changed their name to Tensio. With its 500 employees, Tensio is in charge of 29 000 km of cable, 13 00 substations, and 100 transformer substations throughout Trøndelag. NTE own 40% of the power grid company together with TrønderEnergi (40%) and KLP (20%). [115]

6.1 Case Study: Sørli

This section will give an overview of the industries in Sørli. Sørli is provided as an area of interest for Tensio and NTE, and is therefore chosen for evaluating whether implementing a larger stationary fuel cell system is feasible compared to upgrading the grid infrastructure.

There are a few smaller industries operating in Sørli. Currently, the power demand for the industry park at Sørli is 2.5 MW, which is delivered by the grid. However, there will be considerable industrial development and expansion in the following years, leading to a shortage of capacity in the grid. The main expansion is from two consumers, further referred to as consumers 1 and 2, which will require a considerable power supply. [13]

The planned industrial facilities at Sørli and their respective power demands are shown in table 4.

Table 4: The planned inudstrial expansion in Sørli and the future power demand. [13]

Consumer	Power demand [MW]
Consumer 1	4,2
Consumer 2	4,1
Other	0,1
Sum	**8,4**

The table shows that the power demand in the area will increase quite a lot over the following years, from 2.5 MW to 8.4 MW. In this thesis, however, the industrial expansion and following power demand will not be accounted for based on the limited hydrogen supply accessible from the electrolyser. NTE and Tensio have therefore marked a good starting point to be **1 MW** additional power supply. Consequently, the fuel cell system and grid infrastructure upgrades will be dimensioned to meet this demand. [13]

The Current Grid Infrastructure

Lierne municipality is connected to the 66 kV grid supplied by Tunnsjødal hydropower plant in Trøndelag. Tunnsjødal hydropower is also connected to the 300 kV central grid. There are two power lines at 66 kV to Tunnsjø hydropower plant north of Lierne.

From Tunnsjø hydropower plant, a 66 kV power line is connected to Nordli transformer station. Nordli transformer station has four 22 kV outputs, whereas one is connected to the industries in Sørli. The distance between Nordli transformer station and Sørli is 41 km. [13]

The grid infrastructure in the areas surrounding Sørli is shown in figure 26.

In figure 26, the different connection points of the electric grid are highlighted. In addition, Sørli industrial park is circulated in red. In order for the grid to be able to deliver the future energy demand at Sørli, upgrades in the grid infrastructure are needed. Tensio have done research on the area and have suggested three different alternative solutions. [13]

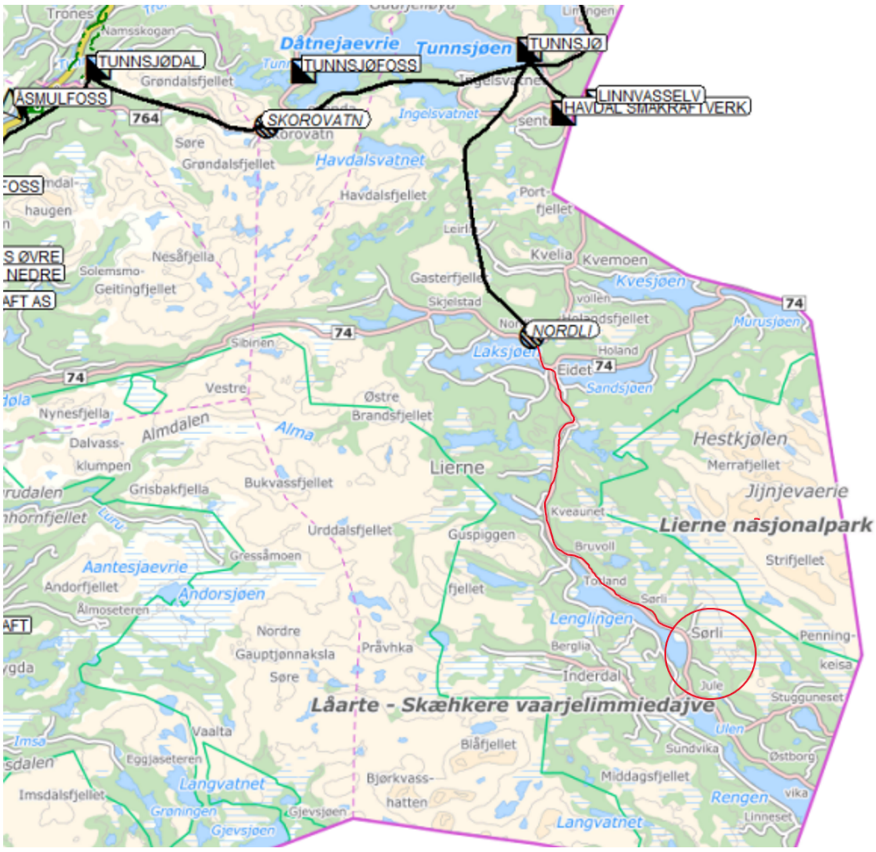

Figure 26: Overview of the grid infrastructure surrounding Sørli. Nordli transformer station delivers 22 kV to Sørli from a distance of 41 km. Modified from [13]. Red marker added to existing figure.

The suggested grid infrastructure upgrades made by Tensio are shown in table 5 below.

Table 5: The different grid upgrade suggestions from Tensio. [13]

Alternative	Description
Alternative 1	66 kV line between Nordli and Botnvika to a new transformer station, and 22 kV line between Botnvika and Sørli.
Alternative 2	66 kV line between Nordli and Botnvika to a new transformer station, and 22 kV underground cable from Botnvika to Sørli.
Alternative 3	66 kV line between Nordli and Sørli, and new transformer station at Sørli.

In the case study at Sørli, there will be made an economical analysis of implementing a stationary fuel cell system to meet the future demand of 1 MW. In this analysis, the suggested grid upgrades presented in table 5 will be used as the reference. Furthermore, the power demand at Sørli industrial park will be analysed, and a fuel cell system will be dimensioned to meet this demand.

6.2 Demand

This section gives an overview of how much energy is consumed by the two industries in Sørli, as well as the transformer station in Nordli. These load profiles will give an idea of how the fuel cell system will have to operate and lay the foundation of what equipment is best suited to provide the industrial site with its required electricity demand. The electricity demand is highly dependent on seasonal variations and types of consumption. Therefore, the load profiles usually vary throughout the year and between consumers. The data sets are provided by Tensio, and are from the start of 2019 until the end of 2021[¶].

6.2.1 Nordli Transformer Station

As figure 26 shows, Nordli transformer station is the closest station to Sørli. The transformer station provides electricity to a large area. Figure 27 shows the load profile of this area from 2019 through 2021. [13]

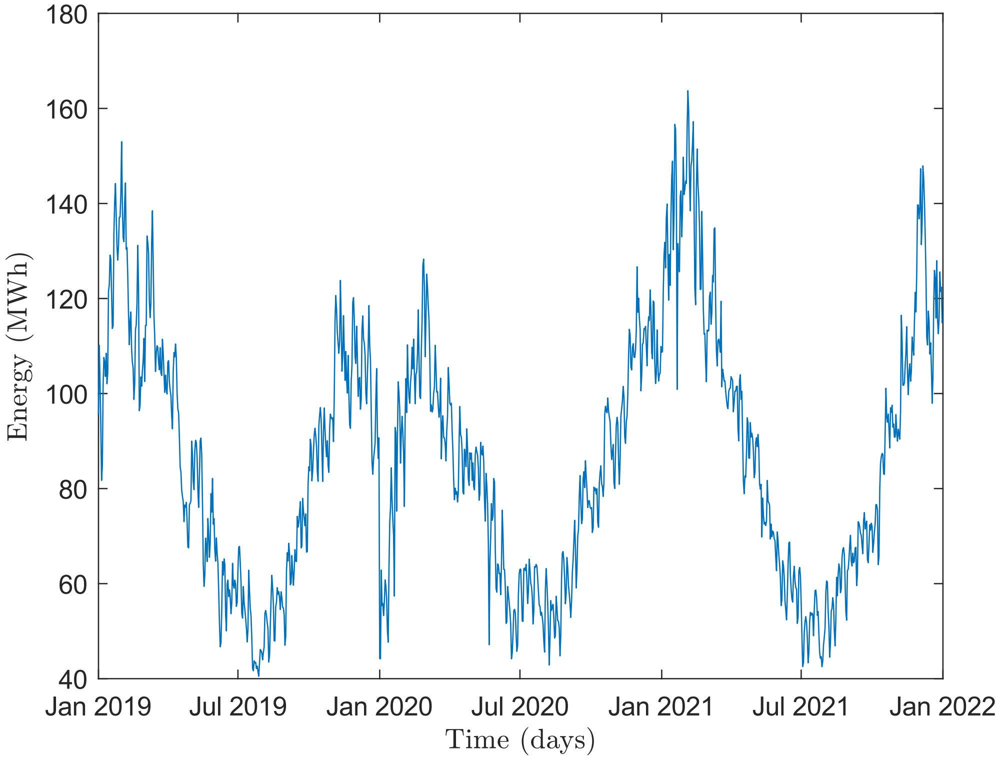

Figure 27: Energy consumption at Nordli transformer station from 2019 through 2021.

The load profile shows a clear trend of high energy consumption in the winter and low energy consumption through the summer. This is a normal energy consumption trend in Norway. The information presented in the following plots is given by Tensio. [13]

Figure 27, is used to illustrate seasonal trends in energy consumption, as well as yearly differences. The system evaluated in this thesis will only consider a part of the demand at

[¶]Note that 2020 was a leap year, and has 366 days

Nordli. More precisely, the study will evaluate the demand from two consumers, presented in the following sections.

6.2.2 Consumer 1

The load profile for 2021, for consumer 1 is displayed in figure 28. The load profile shows clear trends of high energy consumption from Monday to Friday, with a much lower energy consumption during the weekends. There are also three long periods of low energy consumption this year. These dates match Easter, summer, and Christmas times. Appendix A displays more consumption data for consumer 1.

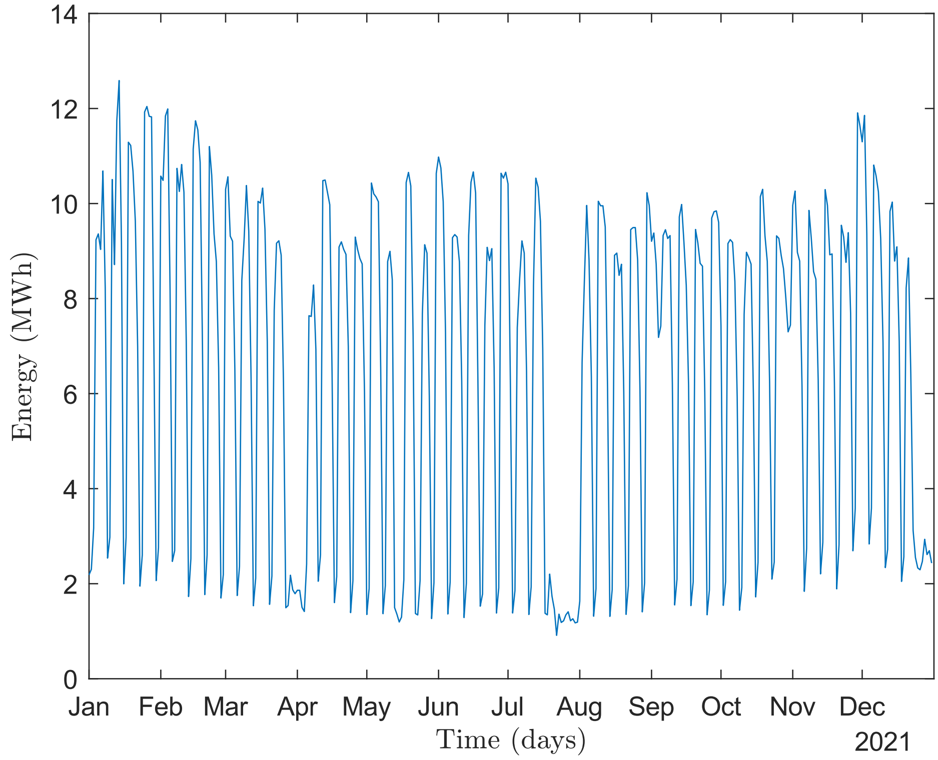

Figure 28: Daily energy consumption in 2021 for consumer 1.

It is easier to evaluate the load the fuel cell system needs to cover by looking at the load in a typical week. Figure 29 shows the load profile for a typical week for consumer 1. As for figure 28, the energy consumption is high during the week, especially from Monday to Thursday. During the weekend, the energy consumption drops by 80-90%. This is probably a result of different machines and processes turned off during weekends.

The average yearly energy consumption for consumer 1 is calculated to be **2.4 GWh**[‖].

[‖]The average energy consumption is calculated using numbers from 2019, 2020, and 2021

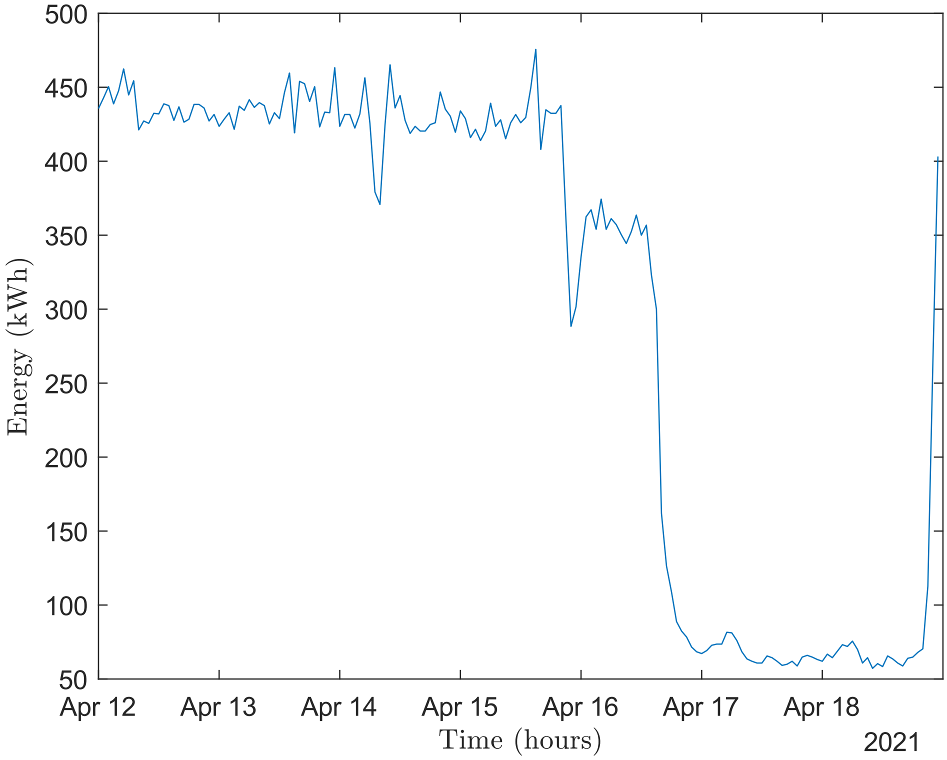

Figure 29: Energy consumption for a typical week for consumer 1. The date of the week is 12th - 18th of April 2021

6.2.3 Consumer 2

The load profile through 2021 for consumer 2 is displayed in figure 30. Figure 31 shows a week in the middle of April 2021, as is done for consumer 1. The figures show that the data from consumer 2 is divided between a 230 V outlet and a 400 V outlet. The load profile shows that consumer 2 has a more consistent demand compared to consumer 1. There are a few uncertainties related to the data from 2021. The data from the 230 V outlet is low for a long period of time, between June and October. As figure 53 in appendix A displays, this low consumption is normal during summer for the 230V outlet normal. However, this period is significantly longer in 2021 compared to previous years.Typically, it is reasonable to believe that there will be a period of low energy consumption during the summer. However, no longer than 3-4 weeks due to summer vacation.

The average yearly energy consumption for consumer 2 is about **4.7 GWh**The average energy consumption is calculated using numbers from 2019, 2020, and 2021.

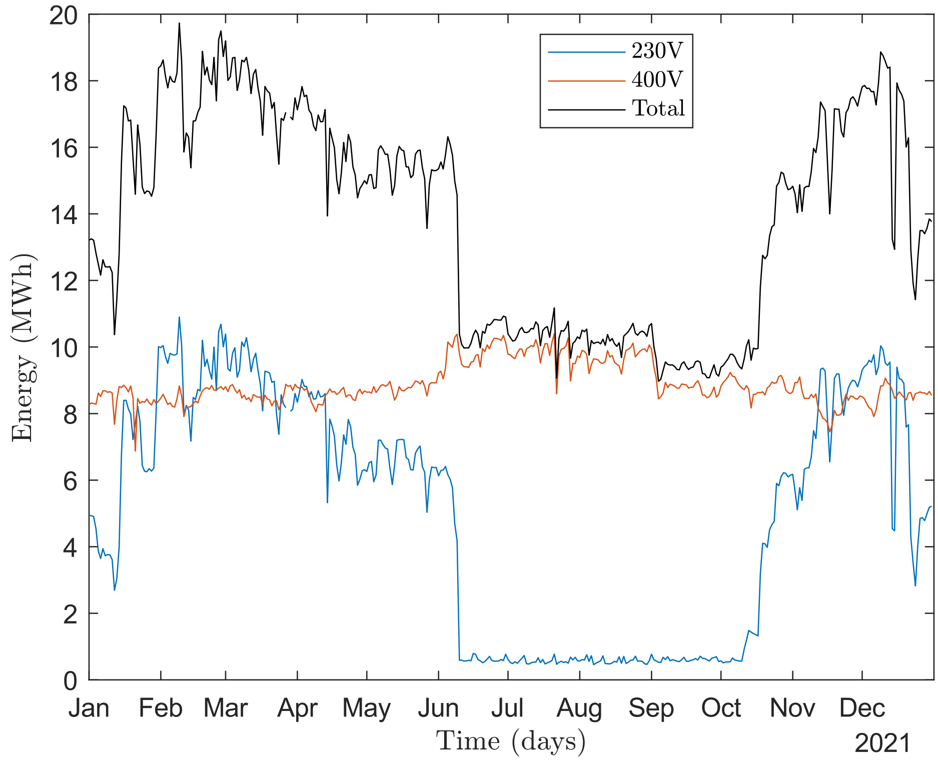

Figure 30: Daily energy consumption from 2021 for consumer 2

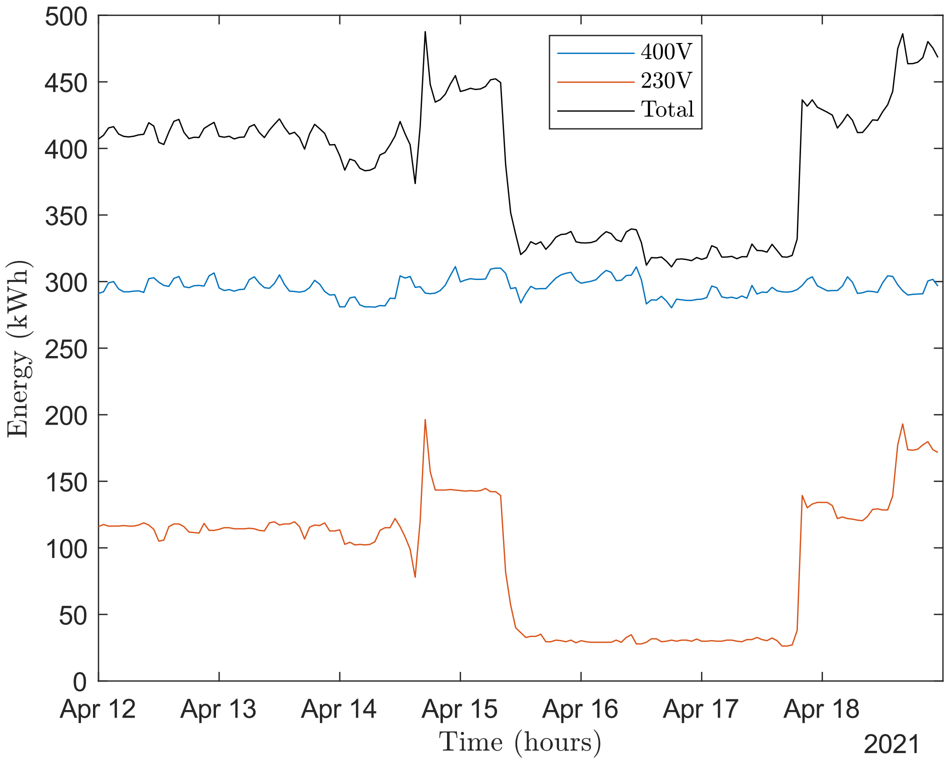

Figure 31: Energy consumption through a week for consumer 2. The date of the week is the same as figure 29: 12th -18th of April 2021

6.2.4 Consumer 1 & 2 Combined

The new demand of 1 MW is combined between consumers 1 and 2. Consequently, it makes sense to look at their combined total energy consumption. By combining their demand, it will be easier to analyse and further predict the future load profile which the fuel cell system will cover. The load profile for their total combined consumption for 2021 is displayed in figure 32.

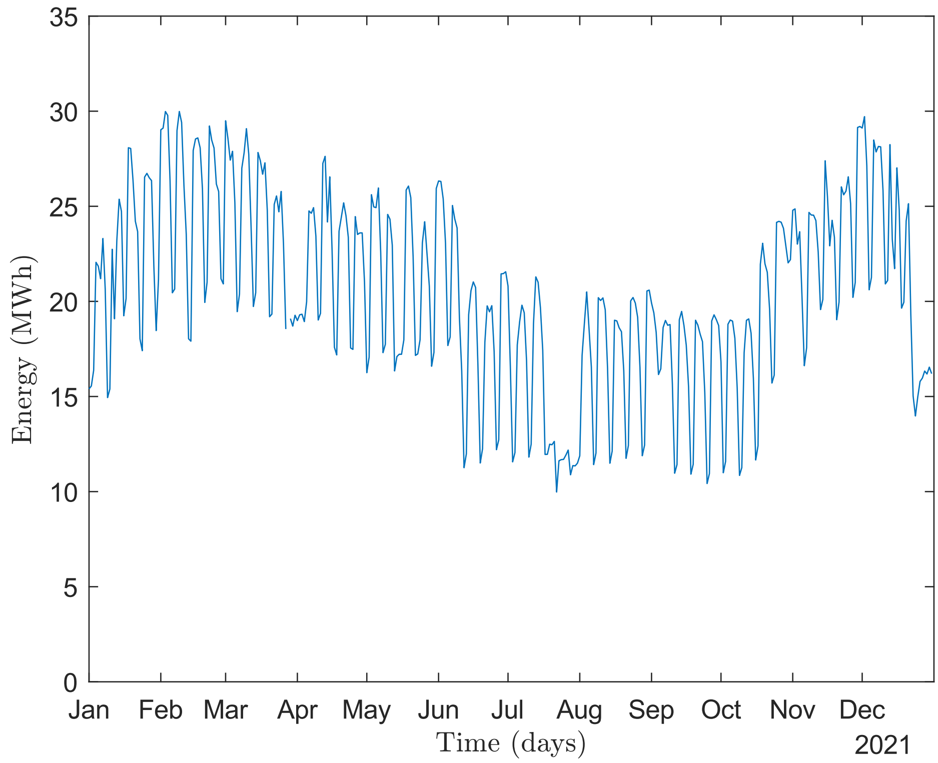

Figure 32: Daily energy consumption during 2021 for consumer 1 and 2.

The load profile from figure 32 shows that the combined load profile shares the seasonal variations with consumer 2, as well as the fluctuations in consumption similar to consumer 1. The graph illustrates the seasonal variations in line with the transformer station at Nordli, where the highest demands occur in the winter, and the lowest periods of demand occur in the summer.

Figure 33 shows a typical week for the combined consumption. As illustrated in the figure, the consumption is high and stable during the week, while it drops significantly on the weekend.

The average yearly energy consumption for the two industries is about **7.1 GWh**The average energy consumption is calculated using numbers from 2019, 2020, and 2021. More energy measurements and data is provided in appendix A.

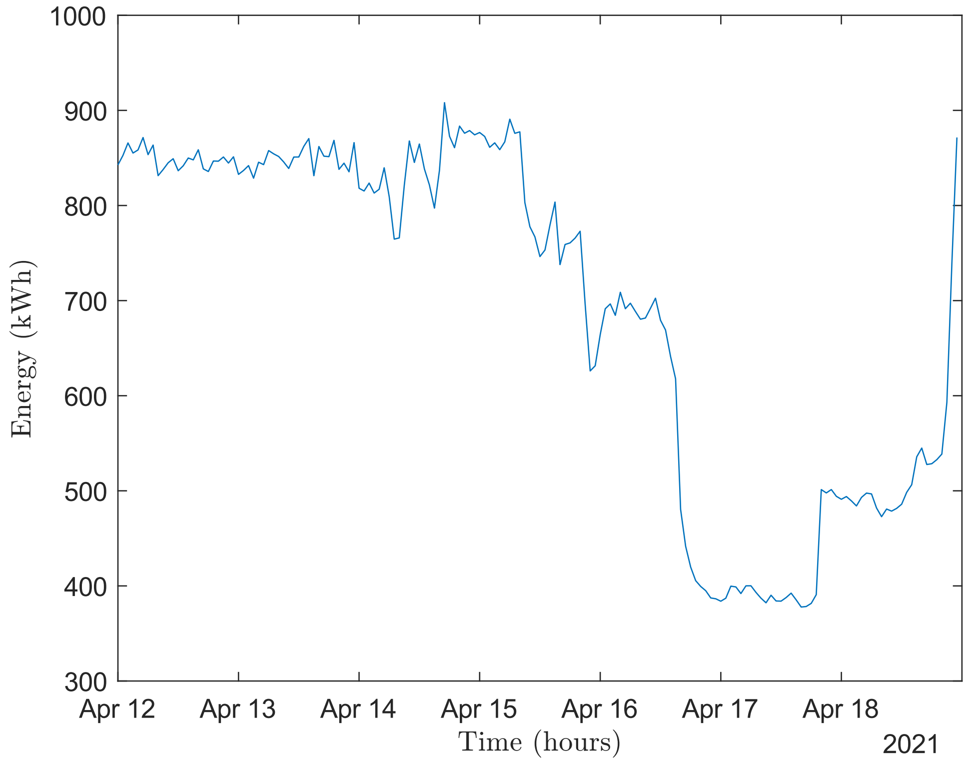

Figure 33: Typical load profile for a week for consumer 1 and 2 combined. The date of the week is 12th-18th of April 2021

6.2.5 Correlation between Power and Voltage

The transformer station at Nordli is, as mentioned in section 6.1, located a distance of 41 km from the industrial site at Sørli. In all electricity transfers, there will be some resistance affecting the voltage. For power lines ranging over longer distances, there are issues of major voltage drops. In addition, high loads on the grid also result in voltage drops, and grid problems may occur when these cases stack. This is the case at Sørli during peak load hours. Resulting in voltage drops close to the lowest limits of voltage quality, which is ±10% of the nominal voltage. This is mentioned in 2.1.3.

The peak load hours are mostly present during the winter, causing previously mentioned problems on the grid. One of these peak load weeks occurs in February 2021. This week is presented in figure 34. The figure shows that the peak energy demand can reach above 1300 kWh during some hours in the winter.

The respective voltage and power values for a similar week in February 2021 are presented in figure 35. In this figure, the correlation between power and voltage becomes clear, as high values of power results in low values of voltage. The voltage ranges from 21.4 kV to around 20.9 kV, pushing the lower limits of voltage quality.

For comparison, the load profile of a week of low demand is presented in figure 36. This figure shows that the demand in this instance is significantly lower than in periods of high demand. The peak demand this week is approximately 850 kWh.

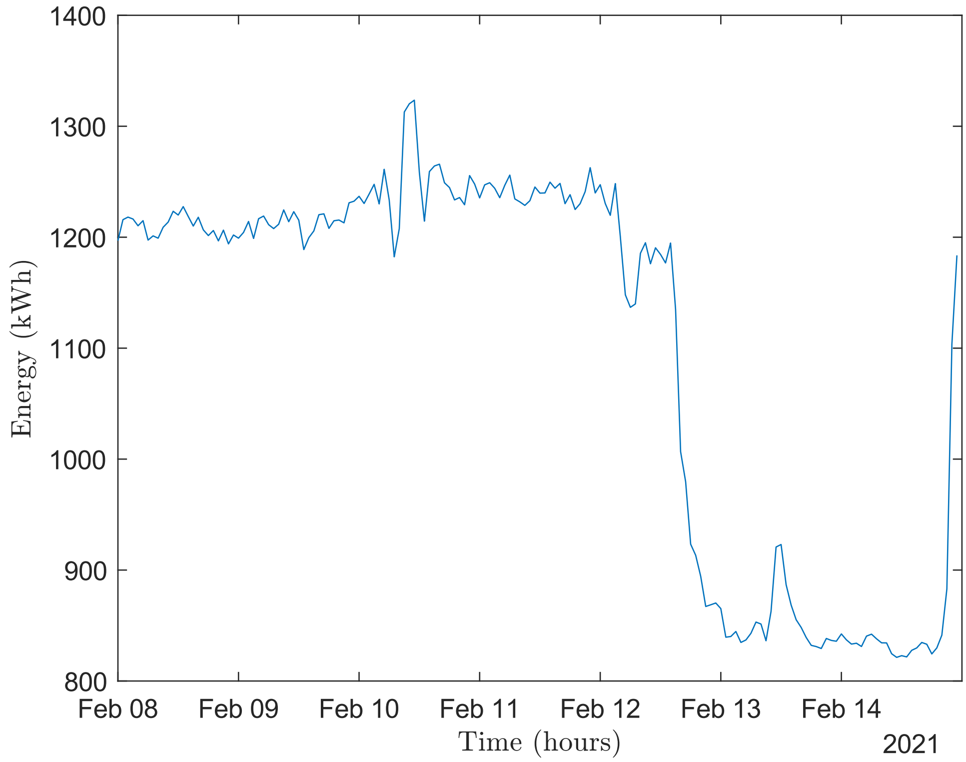

Figure 34: Load profile for the week with the highest energy consumption.

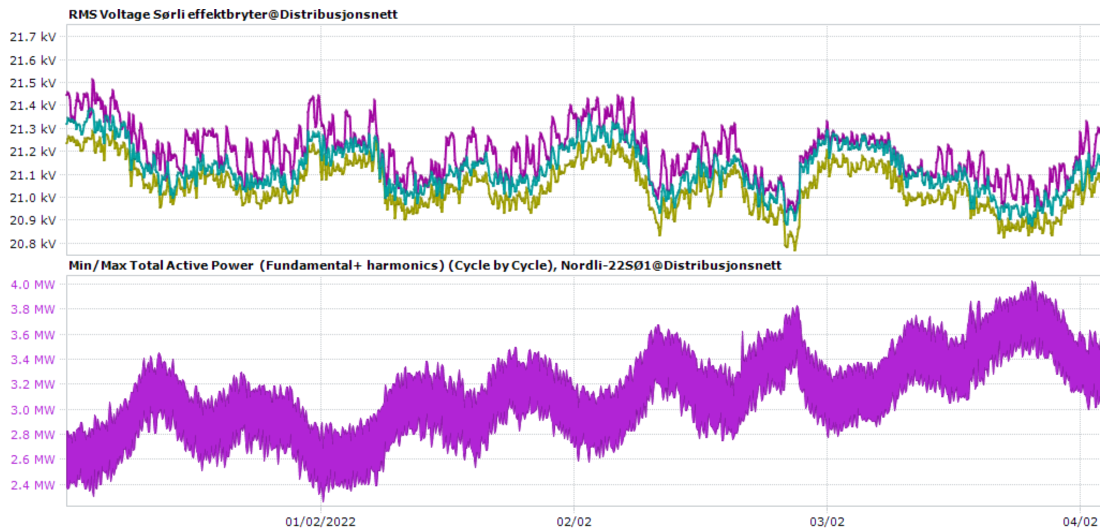

Figure 35: Power and Voltage variations for days in February of high demand. [13]

The respective voltage and power values for a week of low demand are presented in figure 37. For this week, there are negative values on the power graph. This is a result of low demand combined with power production from a local hydropower station. Meaning that for this period, there is much capacity on the grid. The figure clearly shows that the quality of voltage is considerably higher in periods of low demand on the grid. The voltage in this case ranges between 22.3 kV to 21.3 kV. These values are both well within the limits of voltage quality.

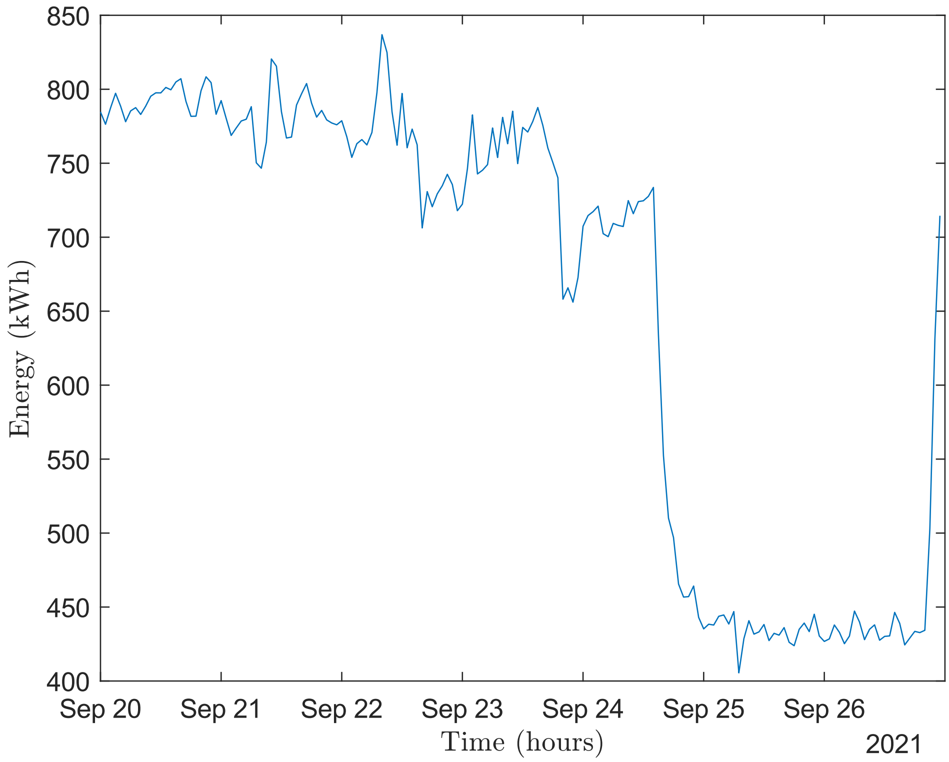

Figure 36: Load profile for one of the weeks with the lowest energy consumption.

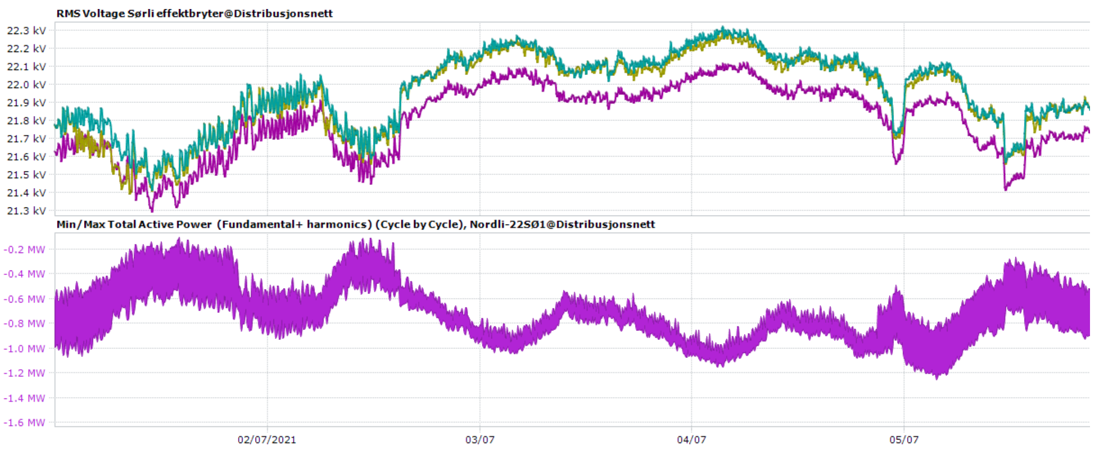

Figure 37: Power and Voltage variations for a week with low demand. [13]

In dialogue with Tensio, one solution for solving difficulties with voltage drops is integrating power supply directly into the grid. A fuel cell system can be operated to supply power to the grid. If the fuel cell system can cover parts of the energy demand, the voltage levels will increase consequently. The increased voltage levels will move the voltage quality over the lower limits previously mentioned.

After expanding 1 MW, these correlating issues of voltage drops on the grid will occur more frequently. When the grid does not have the capacity to meet the new demand, the fuel cell system will have to operate to solve these challenges. This will be the analysis conducted for the fuel cell system operation.

6.3 Designing the System

The system is designed based on the location presented in section 6.1 and the demand at this location. In order to choose adequate equipment needed to supply the industrial site, it is important to consider the entire system. Some of the system specifications and prerequisites are given by NTE. These specifications and prerequisites will be presented in section 6.3.1.

The following list presents the main components of the system:

- PEM electrolyser
- Compressor
- Hydrogen storage vessels
- Transport by tube trailer
- PEM fuel cell

These components are the basis of the economic analysis in this project. The analysis will be divided into two parts. The first part will include the four first points. These points will be used to calculate a LCOH. For this system, the calculated LCOH will be used to find the total fuel cost of the fuel cell system. Furthermore, this will be used to calculate a LCOE for the fuel cell system. This will determine the total cost of the hydrogen solution.

6.3.1 Prerequisites

The data presented in this section results from a literature review, interviews conducted with key hydrogen stakeholders, and a close collaboration with NTE and their partners. NTE has given guidelines for the system in this project, which affects how the cost data is collected. The following list shows the main prerequisites for this project. This list contains information provided by NTE and Tensio.

- Production of 500 kg hydrogen per day by a PEM electrolyser
- The hydrogen needs to be compressed and stored at 350 bar
- The hydrogen will be utilised at a different site. Hence, there is need for transportation of the pressurised hydrogen
- The PEMFC must have a capacity of at least 1 MW
- The operation time of the PEMEC is 360 days per year
- The system has a lifespan of 15 years

These prerequisites define the system and lay the foundations for the LCOH and LCOE calculations. The methods used to obtain cost data are presented in section 6.4.

6.3.2 Choosing Components

As described in section 6.3.1, the prerequisites affect which components can be selected and how the cost data is collected. The dimensions of the different components are selected based on the prerequisites. Most of the collected data is from literature reviews. Data directly collected from manufacturers are used whenever possible. The main components are presented here, while actual costs and key numbers are presented in section 6.4.

Electrolyser

As described in section 6.3.1, the electrolyser will deliver 500 kg of hydrogen per day. It needs to be dimensioned based on this. As presented in section 3.4.2, different types of electrolysers can deliver this amount of hydrogen, but for this project, a PEM electrolyser will be used. A comparison of different PEM electrolysers from different companies are presented in table C.1 in appendix C. For this system, a MC250 containerised electrolyser from Nel Hydrogen is selected. The MC250 is delivered in two containers. The biggest container includes the cell stack and other components, such as the circulation pump and thermal control system. The smaller container consists of MV input, a transformer, and a rectifier. The MV input connects the medium voltage to electrolysis power supply. The key properties of the electrolyser are presented in table 6. Specifications of the MC250 electrolyser is given in detail in table C.2 appendix C.[116]

Table 6: Overview of the most relevant properties for the MC250 containerised electrolyser from Nel. [116]

Net Power [MW]	Production rate [kg/day]	Energy Consumption [kWh/kg]	Efficiency [%]	Lifetime [years]
1.25	531	50*	67*	15

* Calculation is based on LHV and specifications from table C.2 in appendix C.

The data from table 6 is obtained from Nel Hydrogen and NTE. Nel operates with an energy consumption between 47 and 55 kWh/kg for their electrolysers. This results in efficiency between 60-70%. In this case, 50.0 kWh/kg is used as energy consumption. This is based on specifications from table C.2 in appendix C.

Compressor

It is difficult to find available compressors that perfectly match the specifications given by NTE. The electrolyser used in this system has an output pressure of **30 barg**. Other electroysers can provide output pressures higher than this. However, based on discussions with experts in the field and NTE, it is decided to use a separate mechanical compressor to compress the hydrogen from 30 barg to 350 bar. The energy needed to compress hydrogen is of logarithmic scale. In other words, the same amount of energy is needed to compress hydrogen from 1 to 30 bar as to compress it from 10 to 300 bar. Consequently, a electrolyser output pressure of 30 barg can save energy and expenses in the compression process. [12]

For this thesis, a specific compressor has not been chosen. Since the electrolyser for this project is the MC250 from Nel, it is reasonable to assume that the compressor for this system will be produced by Howden. This is a result of the frame agreement that Nel and Howden signed to supply hydrogen compressors in June 2021. [117]

The Howden compressors can be adjusted to the required flow rate and pressure specifications. It is assumed that the compressor has an efficiency of **93%**. This brings the overall energy consumption per kg hydrogen after electrolysis and compression to **53.8 kWh/kg**. [12, 118]

Fuel Cell

It is important to consider the application when evaluating different fuel cell suppliers and different fuel cell technologies. The dimension of the fuel cell is given in the prerequisites. The fuel cell needs to deliver 1 MW of power. Several types of fuel cells can be used to deliver this amount of power. However, each type has its advantages and limitations. Different types of fuel cells for stationary applications are described in section 4.5. The advantages of a PEMFC, among others, are its fast startup and its relatively low operating temperature, as mentioned in section 4.5. This results in better durability because of less wear on system components than other technology that can deliver the needed power. Based on this, a **1 MW PEMFC** is used for this study. [119, 120]

The fuel cell market is still emerging, and sensitive information is trade secrets. Hence, there is little to no information on different types of fuel cells. In addition, prices of larger stationary systems differ a lot from smaller automobile fuel cells, making estimates based on these inapplicable. However, some information is provided by the fuel cell manufacturer Ballard. In the absence of other information, the available information on the Ballard fuel cells ClearGen and ClearGen II are used. The key properties are given in table 7.

Table 7: Overview of the most relevant properties of the ClearGen/ClearGen II PEMFC from Ballard. [121, 122]

Net Power [MW]	Fuel Cons. [kg/hr]	Energy Outp. [kWh/kg]	Voltage Outp. [V]	Efficiency [%]	Lifetime [years]
1	65	15.3*	380-480 AC	46($\pm$2)**	20

* Calculation is based on the given efficiency of the ClearGen/ClearGen II PEMFC and the LHV energy density of hydrogen of 33.34 kWh/kg.
** Efficiency is calculated based on LHV.

To get enough information about the PEMFC, information from both ClearGen and ClearGen II is used. Available specifications of ClearGen II are used whenever possible. Specifications of ClearGen are used where information on ClearGen II is missing or impossible to obtain. Hence, the information in table 7 is referred to as ClearGen/ClearGen II.

Transformer

In order to be able to deliver energy from the fuel cell to the grid, a transformer is needed. The ClearGEN fuel cell system delivers a voltage output of 380-420 V, as shown in table 7, whereas the required grid voltage is at 22 kV. Hence, a transformer will have to make this transition. The information on the transformer is given by Tensio. [13]

Storage Vessels

Available infrastructure, volume to be stored, duration of storage, and required discharge speed are important factors to consider when choosing what storage method to use. As described in section 3.7, there is no hydrogen storage technique considered to be the best fit for all applications. For this study, a stored capacity of 500 kg of hydrogen is needed for each container. The most cost-efficient way to store this amount of hydrogen is with high-pressure storage vessels. In addition, this is the most convenient way of storage based on the available infrastructure in Meråker.

The fuel cell system is stationary. However, tube trailers need to transport the hydrogen to the fuel cell facility. While most needs can be fulfilled by a type I storage vessel, weight becomes an important factor when transportation is needed. As mentioned in section 3.8.1, the weight of the metal vessels adds to the transport cost and limits how much hydrogen can be transported by one truck. This makes the composite pressure vessel more appealing. Furthermore, the composite vessels can store hydrogen at higher pressures than the steel vessels. Hence, larger volumes can be stored, and the traffic from the production site to the consumer can be reduced. This also decreases the energy consumption during transport [123]. As a result, type IV composite vessels are preferred for this study. The specifications of the storage system considered in this study are presented in table 8.

Table 8: Overview of the most relevant specifications of a type IV composite container system. The container contains several smaller cylinders. [124]

Operating Pressure [bar]	Container Size [ft.]	Nominal H2 mass [kg]	Total weight [kg]	Lifetime [years]
318	20	421	8891*	Unlimited
	30	655	13375	
381	20	487	9927	Unlimited
	30	758	14988	

* Total weight of container and hydrogen

The information in table 8 is obtained from Hexagon Purus. They operate with standard sizes, and information is only available for 318 and 381 bar container systems. Table 8 provides comprehensible information on the characteristics of the storage system. An ideal storage system for this project will be within this data span. Consequently, the table gives information about the weight of the storage system.

Transport

Storage and transport are essentially interdependent. As described above, available infrastructure and volume, among others, limit the options. Meråker is located inland. As a result, transport by ships is no option. Furthermore, there is no existing infrastructure for transport with pipelines or railways. The production facility is near European route E14. Hence, transport on the road is the preferred method of transport for this study. The weight is no limiting factor when using type IV composite vessels. In other words, transport with tube trailers is sufficient enough to cover the daily demand for hydrogen at the fuel cell facility.

System Reliability and Availability

The prerequisites give the total load hours of the PEMEC and the PEMFC. The electrolyser is assumed to have five days of maintenance per year. The fuel cell system can operate continuously for baseload power generation or intermittently in periods with high demand [122]. This depends on the power demand at the industrial site. A fuel cell has no moving parts, making the need for maintenance low. This makes the fuel cell system very reliable.

The high efficiency and flexibility of the ClearGEN II PEMFC enable quick start-up and relatively fast ramp-ups, and downs [121]. However, a PEMFC should be run on a steady load to achieve good fuel efficiency and power output. This could also enhance the service lifetime of the PEMFC.

This PEMFC system has limited access to hydrogen. Therefore, the available amount of fuel will be important to determine the operating profile and the system's availability.

6.4 Collecting Cost Data

The following list shows the elements contributing to the costs of the system. These parts are divided to include all elements in the system, from hydrogen production to power supply.

- PEM electrolyser
- Balance of plant components
- Compressors
- Storage vessels
- Electricity and water
- Transport
- Operation and maintenance costs
- PEM fuel cell
- Transformer

- Installation process

The list shows the components needed for the production, distribution, and utilisation of hydrogen. This section presents how these costs are obtained. The costs are described in separate sections. Assumptions and uncertainties are presented together with the description of the cost.

6.4.1 Currency and Exchange Rates

The cost data is collected from sources operating with different currencies. All currencies are converted to NOK. Prices are given in currencies other than NOK are converted to NOK using the exchange rate of April 1, 2022. Figure 38 shows the exchange rate between USD and NOK (USD/NOK) from April 2017 to April 2022.

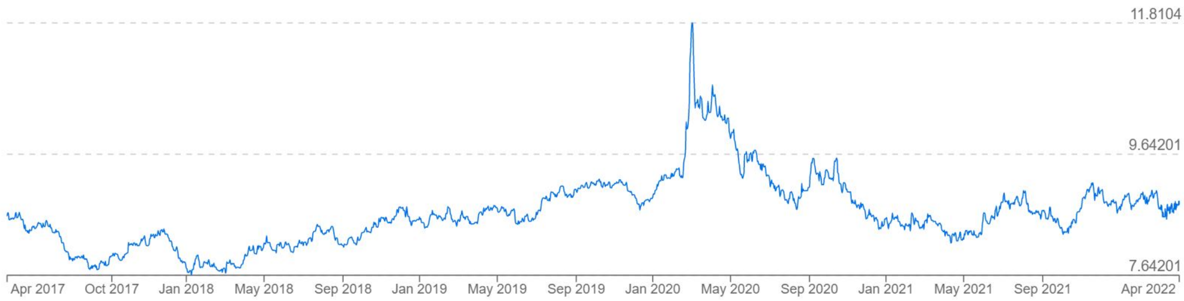

Figure 38: Exchange rates for USD/NOK over the last five years. Highest and lowest exchange rate in the period is shown in the right part of the figure. [125]

Figure 38 illustrates how exchange rates can change over longer periods. The high exchange rates in 2020 are a result of the COVID-19 pandemic. This influenced the national and global economy and significantly impacted the exchange rates. Fluctuating exchange rates can give unnaturally high or low converted prices. However, as shown in figure 38, the exchange rates have been relatively stable over the last period of time. As a result, the current exchange rate is used. The currency conversions for this project are conducted based on exchange rates given in table 9.

Table 9: Exchange rates used to convert currencies to NOK (01.04.2022). [126]

	USD	EUR	GBP
NOK	8.74	9.66	11.48

Table 9 includes the exchange rates from dollar (USD), euro (EUR) and pound (GBP) to Norwegian kroner (NOK).

6.4.2 Electrolyser Costs

The PEMEC system must be able to produce 500 kg of hydrogen each day. It is difficult to find an electrolyser that meets exactly this requirement, an electrolyser close to this was chosen. The MC250 PEMEC from Nel is a 1.25 MW containerised electrolyser, producing up to 531 kg per day. The specifications for the MC250 PEMEC can be found in appendix C. [116]

The cost during a lifetime of an electrolyser is divided into CAPEX and OPEX. NTE provides this cost data.

- The CAPEX of the electrolyser is between **$1500/kW-$2000/kW**. The CAPEX also includes the cost of rectifier, MV input and transformer. [127]
- The yearly OPEX is estimated to be **3%** of the CAPEX. The OPEX includes day to day operational costs and minor maintenance. [128]
- The cell stack has a lifetime of about 10 years. A new cell stack and additional maintenance of other wear parts results in an OPEX of about **40%** of CAPEX every 10 years. [128]

The price of the PEMEC is solely dependent on the installed power. The installed power for this PEMEC system is 1.25 MW. The total CAPEX is calculated to be approximately **21.7 MNOK** with the exchange rates in table 9.

6.4.3 Electricity Costs, Grid Tariffs and Water Costs

Water and electricity are the only inputs needed to produce hydrogen with a PEMEC. Hence, it is important to take water and electricity costs into account when calculating the LCOH. For this thesis, water and electricity costs for the electrolyser and compressor are considered. On the other hand, the water and electricity costs for the fuel cell are not considered. In the operation of a PEMFC, there will be periods when there is a need for cooling and periods when there is a need for heating in order to obtain suitable operational temperatures. For this, both electricity and water are required. However, this is not considered in this thesis due to the lack of available data.

Electricity Costs and Grid Tariffs

The grid rental fee, electricity price, and electricity consumption for the electrolyser and compressor are provided by NTE and Tensio. Further consumption data can be found in detail in appendix C. The electricity price is divided into the grid rental fee and the electricity price. The grid rental fee is calculated from the NH60-tariff. This tariff covers high voltage connections. The MC250 has a transformer and MV input. As a result, the electrolyser is directly connected to the 22 kV distribution grid. This is a cheaper option than the grid company owning the MV input and the transformer. [13]

- The price for electricity is set to **300 NOK/MWh**. [127]
- The grid rental fee is **1.04 MNOK**. [127]

Water costs

Water is used in the electrolysis process for hydrogen production and cooling purposes. Hence, prices for cooling water and process water have to be considered. The process water consumption for the MC250 electrolyser from Nel is not mentioned in the specifications. Theory shows that the consumption of process water in a PEMEC is around 9-10 L/kg$_{H_2}$ produced. For simplicity, 10 L/kg$_{H_2}$ is used. There are uncertainties regarding the amount of cooling water needed for the process due to several factors, such as surrounding temperature. From the literature review, 100 m^3/day of cooling water is estimated for a production of 500 kg$_{H_2}$/day. This value is used in this thesis. NTE have provided process and cooling water costs. Note that the estimate for the amount of cooling water is based on the water being discharged after use. An alternative is to reuse the cooling water in a closed waterborne distribution system. In this case, the amount of cooling water required would be significantly lower. However, this alternative is not considered in this thesis. [3, 129, 130]

- The price of process water and cooling water is **0.348 NOK/m^3**. [127]

6.4.4 Costs of Compression, Storage and Transport

Cost data for compression, storage, and transport are primarily found from companies and manufacturers in the hydrogen market. For these parts, there were highly lacking data found from literature reviews. It is important to emphasise that these costs are highly affected by the storage pressure, amount of stored hydrogen, and distance from production to consumer. Nevertheless, estimates and key numbers provided by the industry are assumed to be accurate enough for this thesis.

Compression costs

As discussed in section 6.3.2, an electrolyser output pressure of 30 barg, will have a huge impact on the compression cost. The compressor will compress hydrogen from 30 barg to 350 bar. The following CAPEX and OPEX are chosen for the compressor. [128]

- CAPEX of **8400 NOK/kg/h**.
- Yearly OPEX of **4%** of CAPEX.
- Replacement needed after **10 years**.

The total CAPEX of the compressor depends on the compression rate of hydrogen. Daily delivery of 500 kg compressed hydrogen corresponds to a compression rate of approximately 20.8 kg/h. To find the total CAPEX of the compressor, the compression rate is multiplied by the listed CAPEX of 8400 NOK/kg/h. This gives a total CAPEX of **1.75 MNOK**.

A mechanical compressor is exposed to significant mechanical stress. This makes the need for maintenance and spare parts important. These costs are covered by the OPEX. The lifetime of the compressor is assumed to be 10 years. Hence a replacement is needed after 10 years. [128]

Storage costs

As described in section 3.7, storing hydrogen efficiently is important for the successful use of this kind of energy storage. The most cost-effective way of storage depends on several factors. For this project, it is only relevant to look at compressed hydrogen storage in high pressure vessels. In addition, the hydrogen needs to be transported from the production site to the use area with tube trailers. This affects what type of pressure vessel can be used. This is explained in section 3.8.1. The cost of composite pressure vessels is higher than steel vessels. However, the choice of storage depends on the application. As a result, a compromise between technical performance and cost competitiveness is needed. As described in section 3.8.1, type IV vessels are used to achieve the required performance of the storage system. This makes it possible to cover the daily demand for hydrogen. For this project, the storage costs are based on the investment and operational costs of a type IV composite pressure vessel. The costs are given in price per kg stored hydrogen. [76, 131]

The following CAPEX and OPEX are provided by Hexagon Purus.

- CAPEX of **600 € /kg**.
- OPEX of **10%** of CAPEX every 10 years.

These costs are in the same order of magnitude as cost data found in the literature. Composite pressure vessels are constructed to several standards. After passing tests and being approved after current standards, the need for maintenance and spare parts is low. However, periodic inspection and testing are required. Based on this, Hexagon Purus operates with an OPEX of 10% every 10 years for their composite pressure vessels [6]. To find the total CAPEX of storage, the needed storage capacity is multiplied by the price per kg of stored hydrogen. To effectively distribute hydrogen from the production site to the end-user, two containers are needed. One container will at all times be supplying hydrogen to the area of consumption, while the other container will be filled up at the production site. As a result, one tonne of storage capacity is needed. This gives a total CAPEX of approximately **5.80 MNOK**.

Transport costs

The transport costs primarily depend on the transportation capacity and the transport distance. There are several solutions for hydrogen supply chains, and more solutions are likely to emerge with increased demands and progress in hydrogen technologies. Different transport and distribution solutions are described in section 3.9. Today, the transport of compressed hydrogen in tube trailers is seen as the easiest option. In addition, it is a cost-effective option compared to other solutions, especially for low to medium demands. For this project, this is the preferred transport option. In addition, an external operator will do the transport. This will give an OPEX, but no CAPEX.

The following OPEX is provided by the carrier company Andersen & Mørck AS.

- OPEX of **10.0 kNOK** from production site to costumer and back with empty container.

- Transport is required **360 days** each year.

Note that this OPEX is based on a given example, where the total transport distance is 300 km. Most carriers operate with zone prices or specify where the container is to be delivered. Hence, more accurate prices are available at both the production site and the place of delivery given. The OPEX includes transport of the container from the production site to the delivery point, with one hour included for offloading and loading of the empty container. Furthermore, the price includes the price of diesel for transport and ADR costs. The OPEX given by Andersen & Mørck AS, matches the expenses from the literature. Figure 51 in Appendix illustrates the how the cost of transportation changes with distance and demand.

6.4.5 Fuel Cell Costs

For this study, a stationary fuel cell system model from Ballard called ClearGen II was used as a reference. The ClearGen II has parameters for a 1 MW PEMFC modular but is scalable by 500 kW increments. The stationary fuel cell market is competitive, and sensitive technical information is trade secrets. Hence making it challenging to find relevant and updated cost data from the literature. However, for the ClearGen II model, cost data was available. As a result, the CAPEX and OPEX of the Ballard application ClearGen II are used for this thesis.

In addition to the CAPEX and OPEX, there will be a need for stack replacement every 15 000 operational hours [127]. For the stack replacement, the cost was between \$240/kW - \$550/kW through the literature review. For this thesis, it is chosen to present the highest price. [132].

As the fuel cell provides a voltage of around 400 V, a transformer is needed to increase the voltage to 22 kV when connected to the grid. After talks with Tensio, the price for a transformer at this scale usually varies between 500 000 - 750 000 NOK. In this thesis, it is chosen to present the highest price. [13]

The CAPEX and OPEX related to the fuel cell are the following:

- The ClearGen II has a CAPEX of **\$1500/kW**. [121, 133]
- The ClearGen II has a OPEX of **\$0.022/kWh** [133]
- CAPEX of stack replacement is set to **\$550/kW**. [132]
- CAPEX of transformer is set to **750 000 NOK**. [13]

6.4.6 Other Costs

Investment costs are non-recurring costs connected to purchasing materials, components, and equipment. Installation costs, costs of administration, and project management are also parts of the investment costs. Whereas installation costs often are given by the manufacturer, administration and project management costs are not. These costs are placed under *Other Costs*. Other costs are based on a model from NVE. [134]

Table 10 presents the model from NVE. This model is based on previous experiences.

Table 10: Share of investment costs for different components of thermal technologies without electricity production. [134]

Component	Share of Investment Costs
Machines and other equipment	65%
Building costs	20%
Project management and administration	15%

Table 10 is used to calculate other costs. *Machines and other equipment* is covered in the other parts of section 6.4. Hence, other costs includes *Building costs* and *Project management and administration*. These costs are included in the total investment cost of the project. Furthermore, it must be considered that these costs may deviate from actual prices and from project to project. Some costs of development and planning are more project-specific than others. Examples are costs that are location-dependent. For this project, the model from NVE is assumed to be sufficient to calculate other costs. Note that the estimates are based on several technologies, not specific to the technologies evaluated in this thesis. However, it is assumed that these estimates can illustrate the costs of administration and building for this project. For both the fuel cell system and the electrolyser, 20% of the investment cost were estimated as building costs. Administration cost is assumed to be 15% of investment cost for both electrolyser and fuel cell. This gives the following CAPEX for building and administration of electrolyser and fuel cell: [134]

- CAPEX of **8.22 MNOK** for electrolyser.
- CAPEX of **4.59 MNOK** for fuel cell.

6.5 Economical Analysis

This section will present the prerequisites and limitations concerning the economic analysis. The economic analysis consists of the LCOH. The LCOH will be used as a basis to calculate the LCOE. The LCOE will be the basis for estimating the cost of the hydrogen solution.

The prices used in the calculations are presented in the previous sections. In addition, the prices are given on the assumption of a production start in 2022, although the production start for Meraker Hydrogen is planned to start in 2024.

There are several parameters in the economic analysis linked to uncertainty. A sensitivity analysis of the main inputs that affect the LCOH and LCOE will be made to provide a good result.

LCOH

The LCOH is the first step of the economic analysis and is calculated using equation 26 presented in section 5.1. Generally, the LCOH gives a price of hydrogen per kg for production. However, the LCOH includes a few more distribution stages in this thesis.

The LCOH is chosen to include the following:

- The production of hydrogen at Meråker.
- Compression of hydrogen to 350 bar.
- Storage of hydrogen in composite vessels.
- Transport of hydrogen to fuel cell system site.

This approach is chosen as the hydrogen will be utilised at the fuel cell system site, making the price of fully distributed hydrogen interesting.

The costs for the different distribution stages of hydrogen are presented in section 6.4. When calculating the LCOH, the discount rate is important. A discount rate of **6%** is used in the calculations.

LCOE

The LCOE is based on the LCOH and the fuel cell system costs. The price of the hydrogen calculated from the LCOH will be an operational cost in the LCOE. The LCOE gives a price for the produced electricity that the fuel cell system can deliver to the grid. The price of the generated electricity conducted from the LCOE and the total amount of generated electricity through the lifetime will give the estimated total price of the hydrogen solution. The LCOE is calculated by using equation 26. A discount rate of **6%** is used in the calculations.

Sensitivity Analysis

There has been conducted a sensitivity analysis for both the LCOH and LCOE. The sensitivity analysis is made to show how different variable inputs affect the total overall outcome of these prices. Two parameters for each levelised cost analysis are chosen. The variables affecting the total outcome the most have been chosen for evaluation.

- For the LCOH, the input variables chosen for the sensitivity analysis are electricity price and CAPEX.
- For the LCOE, the input variables chosen for the sensitivity analysis are hydrogen price and CAPEX.

Electricity Cost Comparison with Diesel

In order to evaluate whether a hydrogen solution is competitive or not, it is important to compare it with other relevant technologies. As elaborated in section 4.5, diesel generators do several tasks that fuel cells probably can solve in the future. One of the near-term steps to gain fuel cell experience is to change from diesel gensets to fuel cell solutions for backup power generation.

In this section, the LCOE of a diesel genset used for backup power solutions will be presented to create a basis to evaluate the competitiveness of hydrogen.

The LCOE for the diesel genset is based on a comparative evaluation from Ballard, where the ClearGen II fuel cell system was compared to one of Cummins's most popular diesel gensets for backup power generation.

Ballard have presented a LCOE for the Cummins model QSK60-G7 diesel genset. The key assumptions Ballard based their LCOE on were: [133]

- CAPEX of **$800/kW**.
- Discount rate of **6.5%**.
- Lifetime of **12 years**.
- Diesel price of **$0.85**.
- Operation and Maintenance cost of **$0.04/kWh**.
- LCOE of **$0.32/kWh**, of which 80% of the price is related to fuel cost.

However, for this thesis, the diesel cost is replaced with the Norwegian diesel cost, as the hydrogen price is estimated for the Norwegian market. The Norwegian diesel price is set to 15.75 NOK excluded VTA and road usage tax [135]. The LCOE will be scaled up to follow the Norwegian price of diesel.

There will also be made a prediction of the diesel price for 2030. In this prediction, it is assumed that the carbon tax will increase from 590 NOK/tonnes$_{CO_2}$ to 2000 NOK, as the Norwegian government proposed in 2021 [136]. Other taxes are assumed constant.

7 Results

In this section, the results of the thesis are presented. The results will analyse the future demand and how a fuel cell system can be operated to meet this demand. Furthermore, the fuel cell operation profiles and the hydrogen demand are illustrated graphically. The cost of implementing a fuel cell system will be compared to upgrading the grid, using the economical analysis tools LCOH and LCOE. Finally, the fuel cell is compared to a diesel genset to evaluate competitiveness with other similar technologies.

7.1 New Demand

The industries in Sørli want to expand their production. As a result, an upgrade of the grid capacity is required, as discussed in section 6.1. For the expansion of 1 MW, a simulation of a possible new load profile is displayed in figure 39.

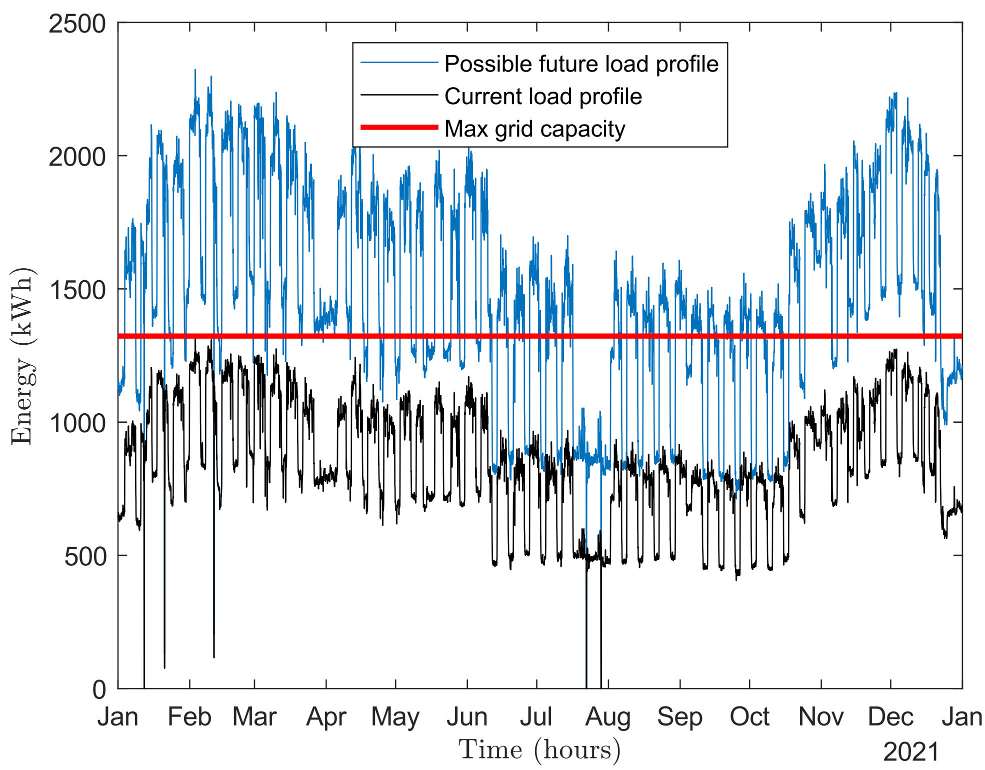

Figure 39: Simulated load profile after 1 MW expansion for combined consumers 1 and 2.

The simulation in figure 39 is based on the load profile from 2021, represented by the black line. This is the same graph as presented in figure 28. The red line represents the peak energy consumption for one hour in 2021, namely 1323 kWh. The average power for this hour is 1323 kW. For this case, the peak energy consumption also represents the maximum capacity of the grid. The 1 MW expansion is represented by the blue line. Here, 1 MW is added as average energy consumption of over one hour. Consequently, 1 MWh is added to the peak energy consumption of 1323 kWh. This gives a new peak energy consumption of 2323 kWh. The 1 MWh has been added as a percentage of the maximum load. Meaning all consumption values were converted to a percentage of the maximum value. These percentages were multiplied by the new maximum energy consumption of 2323 kWh. This gives the new load profile illustrated as the blue line in figure 39. For instance, if the load from one hour in 2021 was 50% (662 kWh) of the max load, 500 kWh would be added to this hour. The simulated new demand for this hour would then be 1162 kWh.

7.2 Implementation of PEMFC in the Grid

In this section, the implementation of a PEMFC stationary system in Sørli will be evaluated. The fuel cell system model evaluated will be a merge of the Ballard models ClearGEN/ClearGEN II, which specified operation data is presented earlier in table 7 in section 6.3.2. The fuel cell system will need to meet the increased demand in Sørli.

The main problems for the grid occur in the winter months, as mentioned in section 6.2.5. In the periods of highest demand, the load resulted in issues with voltage drops. As the load increases with the 1 MW expansion, these issues will occur more frequently. In an attempt to account for this, the PEMFC system will operate whenever the blue line in figure 39 exceeds the red line. These are the periods that are assumed problematic for the grid.

Hydrogen supply to the fuel cell system determines the operation possibilities, as the fuel cell can not operate without fuel. However, the hydrogen supply is limited to an amount of 500 kg per day. This makes it important to look at the hydrogen demand required for operating the PEMFC system for the different periods of the year.

If a fuel cell system is implemented in the grid for this case, the fuel cell would need to generate electricity when the blue line exceeds the red line. The total energy the fuel cell would need to deliver can be found by summing all the energy demand over the red line. The yearly demand the fuel cell would have to cover for this case is **2.24 GWh**. This energy demand can be calculated to the equivalent amount of hydrogen in kg by using equation 19 presented in section 4.1. This results in a total demand of 146 000 kg_{H_2}/year with the ClearGen II efficiency of 46%. This equals an average consumption of approximately 400 kg_{H_2}/day. Meaning that the supply from Meråker is sufficient when evaluated on an average daily supply and demand. However, the frequent changes in demand during the year, which is illustrated in figure 39, show that the distribution of hydrogen will have to be planned in correlation to the demand.

As figure 39 illustrates, the load profile varies a lot throughout the year. There are periods where the blue line exceeds the red line for most hours and periods where the blue line hardly ever exceeds the red line. Consequently, there will be periods of hydrogen demand exceeding the daily supply of 500 kg and periods of lower demand than 500 kg. For this reason, the week of highest demand, a mean week for the winter, and a week of low demand has been chosen to illustrate the different demands of hydrogen for the different periods of the year.

Week of Highest Demand

As mentioned, the winter months are when the grid most frequently suffers problems with voltage drops. Therefore, the week of highest demand during the year, a week in February, is presented. This week in February is the week the fuel cell operation is most essential to secure grid voltage quality and sufficient power.

The week of highest demand from figure 39, is enlarged and displayed in figure 40. The graph shows that the blue line exceeds the red line for the whole week, which means that for this particular week, the fuel cell system would need to generate electricity for the entirety of the week.

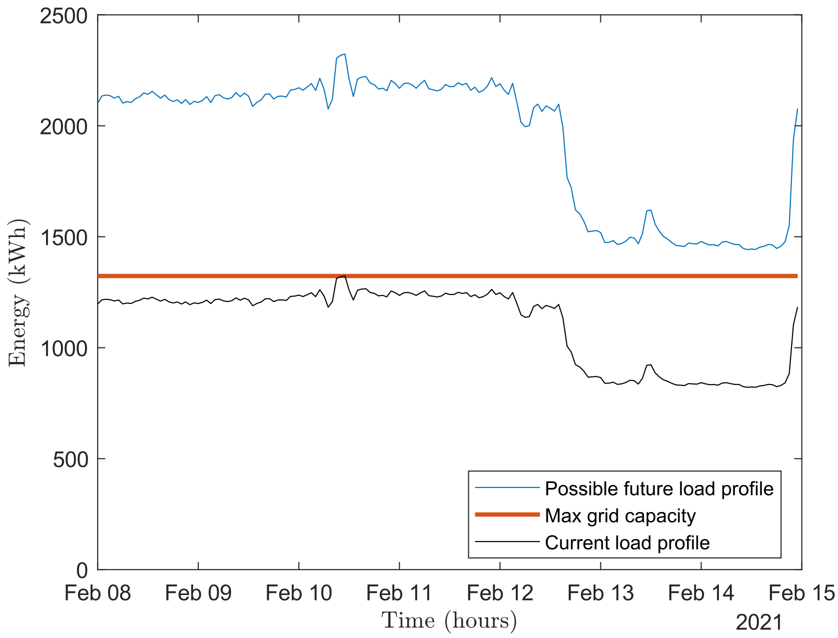

Figure 40: Energy demand plotted on hourly basis for the week with the highest demand during the year.

Figure 40 shows the energy demand for each hour throughout the week. The energy demand is high the entire week. Meaning this week represents one of the weeks of highest hydrogen demand. The energy demand the PEMFC will need to cover is calculated by subtracting the value of the red line, which is 1323 kWh, from the value of the blue line for every hour. This difference indicates the amount of energy the grid can not cover alone.

The hourly energy demand needs to be converted into daily hydrogen demand in order to evaluate the amount of hydrogen needed. The energy demand the PEMFC must cover is summed up for all 24 hours each day. The energy demand per day for the week with the highest demand is presented in figure 41. The electricity output that the fuel cell system must deliver is calculated into the equivalent hydrogen demand, using equation 19 in the same manner as in the previous section. The total hydrogen demand for each day this week is also presented in figure 41.

The projected amount of hydrogen supply for the PEMFC system is 500 kg per day.

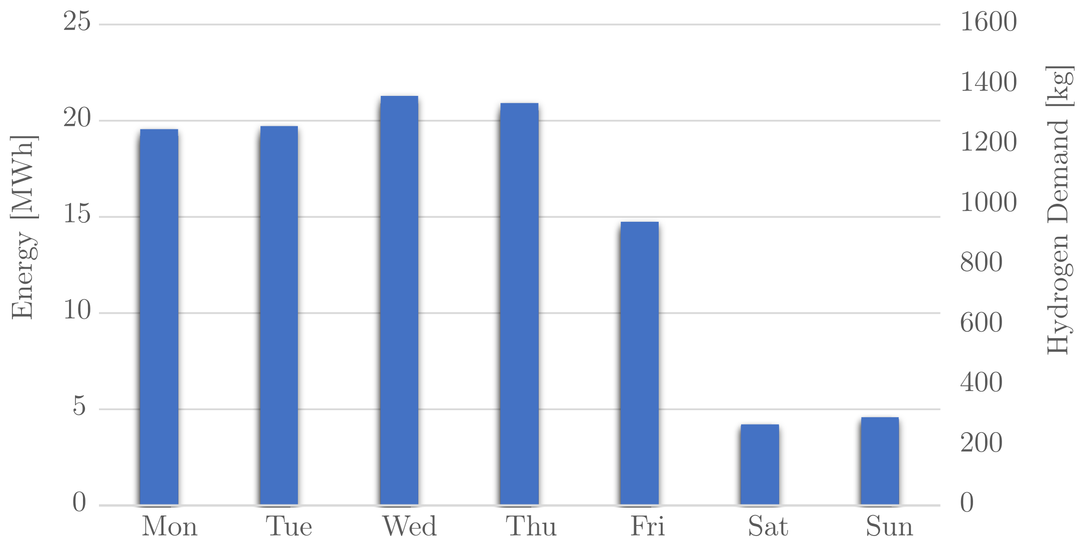

Figure 41: Hydrogen and energy demand for the week with the highest demand in 2021.

Figure 41 however, illustrates that the demand for hydrogen from Monday to Friday far exceeds this amount. The demand peaks on Wednesday, resulting in the need for approximately 1400 kg of hydrogen for the PEMFC operation this day. In comparison, the hydrogen demand is lower than 500 kg on Saturday and Sunday. On-site hydrogen storage in the days of low demand will therefore be essential to cover periods of high consecutive demand.

The Week following the Week of Highest Demand

The week with the highest demand is, as mentioned, the week most critical for the grid. However, there are more weeks where the grid has problems delivering sufficient power and voltage. It is interesting to look at variations in demand between weeks and how much the demand shifts from one week to another. For this reason, the week following the week of highest demand is presented in figure 42.

As figure 42 shows, the energy demand for this week is above the red line, similarly to the week of highest demand. However, the blue line does fall below the red line for some hours this week. This illustrates how the demand changes from week to week. The daily hydrogen demand this week is presented in figure 43, together with the energy demand.

Figure 43 shows that the daily hydrogen demand is high and in the same order of magnitude as the previous week, especially early to mid-week. Interestingly enough, the graph also shows no need to operate the fuel cell system on the weekend. This means that the fuel cell system for this period could be turned off, and the supply of hydrogen these days could be stored on-site, ready to be utilised the next day of high demand.

Week of Low Demand

For comparison, a week during the summer will be presented. As the two previous sections indicated, there will be weeks in which the hydrogen demand far exceeds the weekly supply

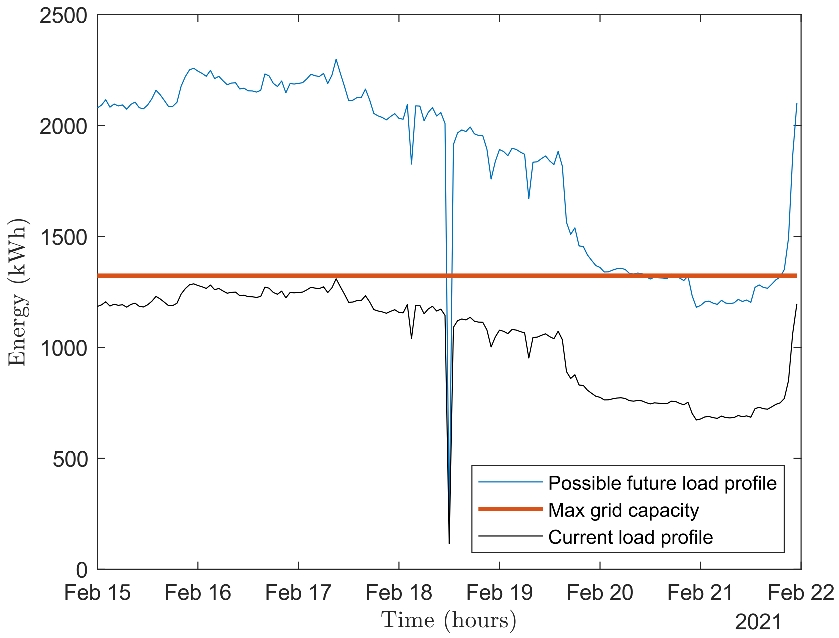

Figure 42: Energy demand plotted on hourly basis for the week following the week of highest demand

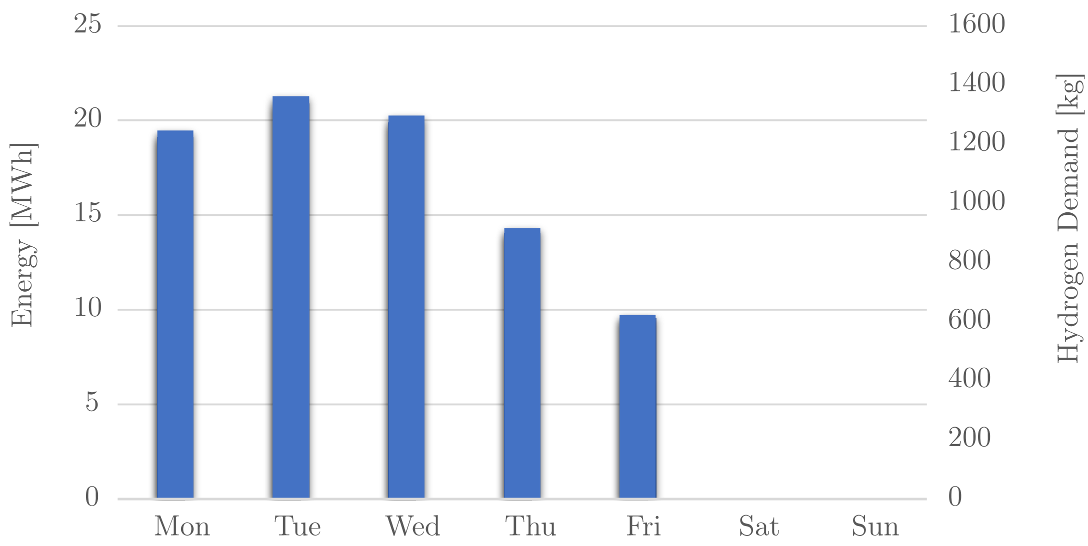

Figure 43: Hydrogen and energy demand for the week following the week of highest demand.

from Meråker. In order to be able to meet the weeks of high demand, on-site hydrogen storage is needed during periods of low demand. This amount of hydrogen will have to be stored for long periods and utilised in the hours of highest demand. These weeks, when the demand is low for a substantial amount of time, are usually present during the summer, as figure 39 illustrates. In figure 44, one of the weeks with low demand is presented.

Figure 44 shows the demand for a week during the summer. The graph shows that the energy demand for this week is considerably lower than for the week of highest demand,

Figure 44: Energy demand on hourly basis a week in the summer

shown in figure 40, and the following week in figure 42. There is a significant amount of hours below the red line for the low-demand week. This means that there will be fewer hours the fuel cell system will have to operate.

In figure 45, the daily amount of energy that the fuel cell will have to deliver is presented. The equivalent amount of hydrogen required to deliver this energy output is also presented.

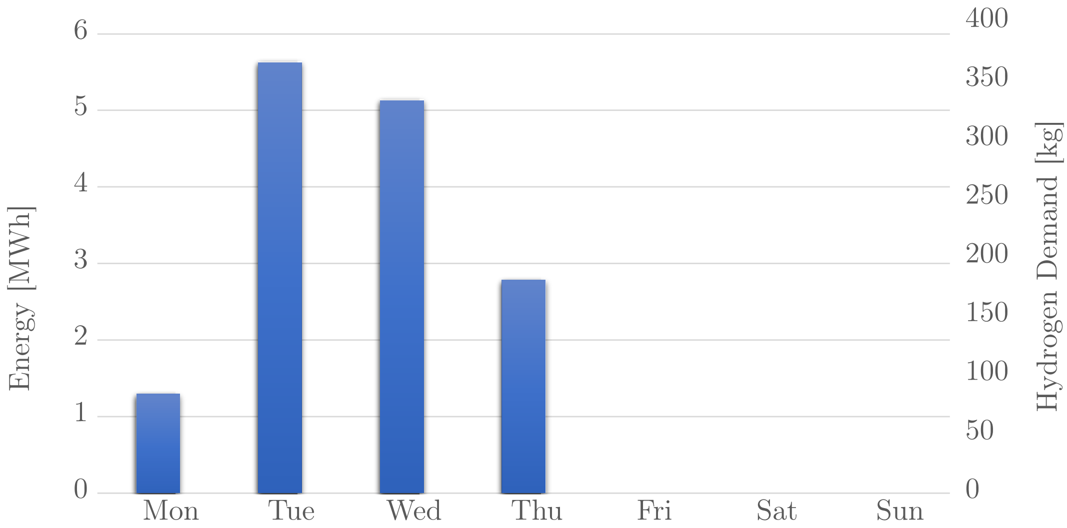

Figure 45: Hydrogen and energy demand on daily basis for a week during the summer.

As presented in the figure, the hydrogen demand is minimal in the summer week compared to the two weeks of high demand in the winter. In this case, the demand is lower than the daily production volume every day of the week. During the weekend, there is no need for hydrogen supply to Sørli at all. Consequently, there would be a surplus of supply, which could be stacked up to meet periods of high demand or utilised in other facilities. This aspect will be discussed further in section 8.4.1.

7.3 Levelised Cost of Hydrogen

The LCOH calculations for this system is carried out with the cost data from section 6.4 and equation 26 presented in section 5.1. The system costs are divided into OPEX and CAPEX.

CAPEX

Table 11 shows the different investment expenditures related to the production and distribution of hydrogen. These are used to calculate a total CAPEX, which further are used when calculating the LCOH.

Table 11: Total CAPEX for LCOH. The components and prices are accounted for in section 6.4.

	Electrolyser	Compression	Storage	Other Costs	Total CAPEX
[MNOK]	21.7	1.75	5.80	8.22	37.5

As table 11 shows, the investment costs of hydrogen production facility are high. The electrolyser makes up the highest share of the CAPEX. *Other costs*, which is calculated using the NVE model described in section 6.4.6, is the second highest share. *Other costs*, is the cost of construction, administration, and building plot. The shares of the CAPEX are represented in figure 46.

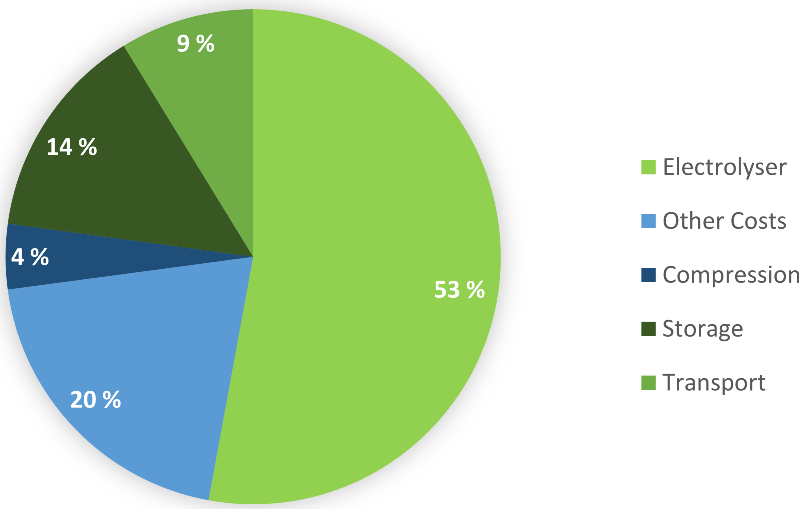

Figure 46: Sector diagram of the shares of CAPEX included in the LCOH.

As figure 46 shows, the electrolyser has the most significant share of the CAPEX for the production and distribution of hydrogen. The electrolyser CAPEX makes up over 50% of the total CAPEX. Storage and *Other Costs* also have pretty big shares, namely 14% and 20%. The CAPEX of compression and transport is pretty small compared to the other shares.

OPEX

The total OPEX is presented in table 12. The OPEX represents the cost of running the electrolysis facility. The total OPEX during the lifetime is calculated using a discount rate of 6%. The operational costs will most likely vary throughout the lifetime of the facility. For instance, a variation of the electricity price will have a distinguishable alteration on the total OPEX, as it is the highest operational cost.

Table 12: Total OPEX for the LCOH. The components and prices are accounted for in section 6.4.

	Electrolyser	Compressor	Storage	Transport	Water and Electricity	Total OPEX
[MNOK]	11.2	1.66	0.324	35.0	38.5	86.6

The OPEX is divided into different parts in table 12. Some parts, like transport, only have a yearly operational cost. The electrolyser has both a yearly OPEX and an additional OPEX after 10 years due to stack replacement. Since the lifetime of the system is fifteen years, this OPEX is only accounted for once.

LCOH

By including all capital and operational expenses, the LCOH can be calculated using equation 26 presented in section 5.1. The LCOH has been calculated in three steps, namely production and compression, storage, and transport. The results from the different stages of the LCOH calculations are presented in table 13.

Table 13: LCOH prices for the different Distribution Stages

Distribution stage	LCOH Price
Electrolysis and Compression	47.5 NOK/kg_{H_2}
Storage	51.0 NOK/kg_{H_2}
Transport	71.0 NOK/kg_{H_2}

The total LCOH is calculated to be **71.0 NOK/$\mathbf{kg}_{H_2}$**. As table 13 presents, the electrolysis and compression part of the distribution stages is the most expensive. Storage accounts for a small part of the total LCOH price, whereas transport is a major contributing part. The cost of storage and transport will be discussed in section 8.5. With a LCOH price of 71 NOK/kg, the total cost of hydrogen fuel for the fuel cell system would be **101 MNOK** over the lifetime of the system.

Sensitivity Analysis

The data used to calculate the LCOH is subject to high uncertainty. This makes it difficult to give one exact value for the LCOH. As described in chapter 5, some of the data used to calculate the LCOH affect the LCOH value significantly. For this reason, it is conducted a sensitivity analysis for the two parameters that affect the LCOH the most. Changes in CAPEX of electrolyser and electricity price affect the LCOH the most.

Figure 47 shows how the LCOH value changes with electrolyser CAPEX. All other parameters are held constant. The CAPEX is given in price per kW, and the analysis is conducted for prices between 4000 and 22000 NOK/kW. Figure 48 shows how the LCOH changes with the electricity price. The electricity price ranges from 0.15 to 0.95 NOK/kWh. Both figures include a mark at an LCOH of 71.0 NOK/kg.

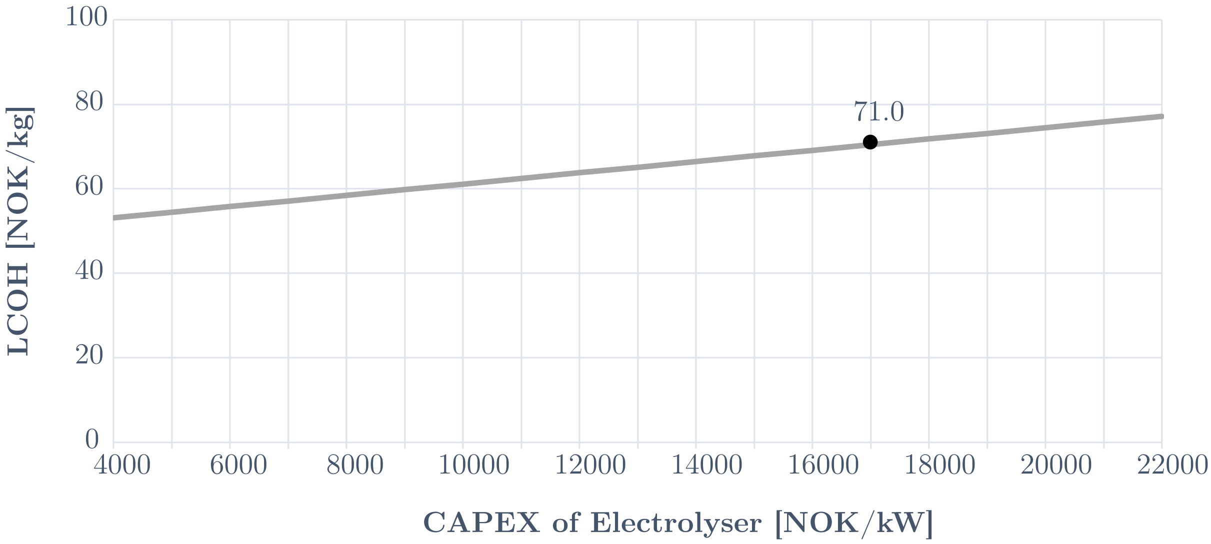

Figure 47: The LCOH price for different electrolyser CAPEXes.

Figure 47 shows the sensitivity of the LCOH in correlation to electrolyser CAPEX. The current CAPEX, which gives a LCOH of 71.0 NOK/kg, is around 17 000 NOK/kW based on a 1.25 MW electrolyser. The electrolyser CAPEX will, according to several sources, decrease in the future as a result of technological innovation and economies of scale. The LCOH has the potential of price reduction if electrolyser prices are decreased as forecasted.

Figure 48 illustrates the change in LCOH as a result of changing electricity prices. The figure also shows the electricity price that is used for the LCOH calculations, which is 0.3 NOK/kWh. Recent periods have shown how quickly electricity prices can change in Norway. The electricity price will likely change in the future as a result of electrification and higher shares of renewable energy. As a result of uncertainty regarding electricity prices, it is good to understand how changing electricity prices would affect the LCOH.

Table 14 shows the sensitivity of the LCOH to changes in both electrolyser CAPEX and electricity price. The colours present the LCOH in NOK/kg from low (green) to high (red). Table 14 the current price of the conducted LCOH lies in the mid-price area illustrated as yellow. The sensitivity analysis is carried out for electricity prices between

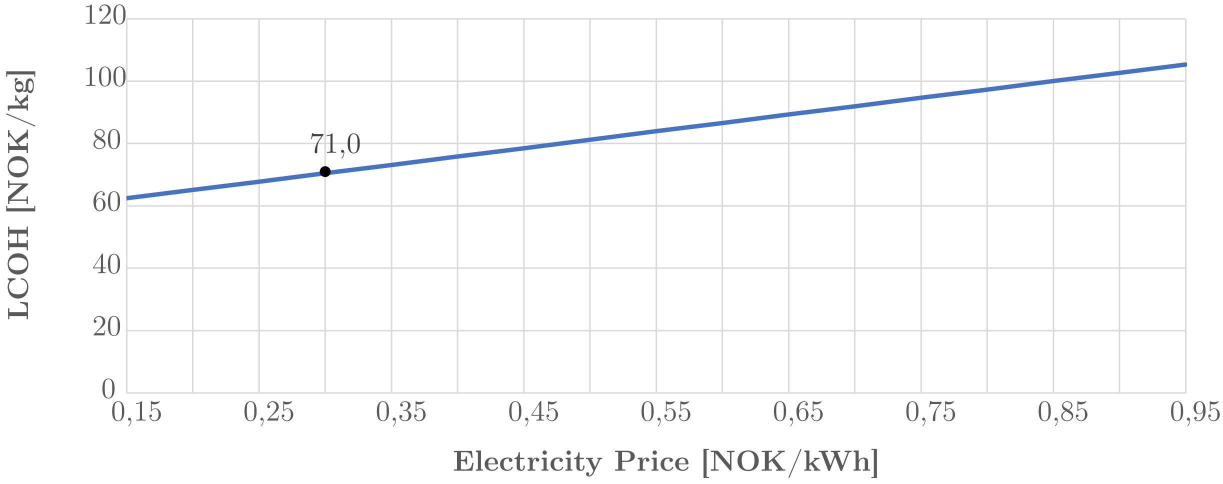

Figure 48: The LCOH price for different electricity prices.

0.15 and 0.75 NOK/kWh and electrolyser CAPEX between 4000 to 20000 NOK/kW. A smaller selection of numbers is used here, compared to figure 47 and 48.

Table 14: Sensitivity analysis of the LCOH based on changes in electricity price and electrolyser CAPEX.

	Electricity Price [NOK/kWh]				
NOK/kg — Electrolyser CAPEX [NOK/kW]	0,15	0,3	0,45	0,6	0,75
4000	45,1	53,1	61,2	69,3	77,3
8000	50,4	58,5	66,5	74,6	82,7
12000	55,7	63,8	71,9	79,9	88,0
16000	61,1	69,1	77,2	85,3	93,3
20000	66,4	74,5	82,5	90,6	98,7

Table 14 shows that the LCOH price is more sensitive to changes in the electricity price than the CAPEX of the electrolyser. This is a result of the electricity being the most considerable expense throughout the electrolysers lifetime.

7.4 Levelised Cost of Electricity

In the same way as the LCOH provides a cost per unit of hydrogen, the LCOE provides a cost per unit of electricity. The LCOE is calculated based on equation 27, presented in section 5.2.

CAPEX

Table 15 shows the CAPEX for the different components related to the LCOE. In the same way as for the LCOH, these expenses are used to find a total CAPEX. This total CAPEX is used when calculating the LCOE.

As shown in table 15, the biggest share of the CAPEX comes from the fuel cell. In

Table 15: The CAPEX of the components and fuel related to the LCOE.

	Fuel Cell	Transformer	Other Costs	Total CAPEX
[MNOK]	13.0	0.750	4.60	18.4

addition, a transformer is needed to convert the output voltage from the fuel cell up to the line voltage in the grid, as described in section 2.1.1. The output voltage from the PEMFC is 380-480 V, as shown in table 7. As a result, a transformer is needed to convert the voltage from 380-480 V up to 22 kV. *Other costs* is based on the model from NVE, presented in table 10. *Other costs* include the building costs and administration costs of the fuel cell.

OPEX

In addition to the CAPEX presented in table 15, the LCOE price is highly affected by the OPEX. The OPEX consists of the yearly operational cost, stack replacement, and fuel cost for the fuel cell system. The calculated LCOH value is used as the fuel cost. The yearly operational cost and the cost of stack replacement are based on the data presented in section 6.4.5. The total OPEX of the components and fuel related to the LCOE is presented in table 16.

Table 16: The total OPEX of components and fuel related to the LCOE.

	Fuel Cell	Stack Replacement	Cost of Hydrogen	Total OPEX
[MNOK]	4.18	12.7	101	118

Table 16 shows that the cost of hydrogen is by far the most expensive operational expense. The cost of hydrogen accounts for 86% of the total OPEX included in the LCOE. Consequently, it is the major contributor to the value of the LCOE. This is further illustrated in the following sections.

LCOE

By including all capital and operational expenses, the LCOE can be calculated using equation 27 presented in section 5.2. The LCOE was calculated to be **6.25 NOK/kWh**. The LCOE represents the price of the electricity generated by the fuel cell.

Sensitivity Analysis

Figure 49 and table 17 shows how the LCOE changes with different variables. The most important variables for the LCOE are the hydrogen price, calculated from the LCOH, and the fuel cell CAPEX.

Figure 49 shows how the LCOE changes with the fuel cell CAPEX. The change is based on three different hydrogen prices. The low price is 30 NOK/kg, the medium price is 70 NOK/kg, and the high price is 110 NOK/kg. The low price is based on a future scenario from IRENA regarding hydrogen prices towards 2050 [48]. The medium-priced is based

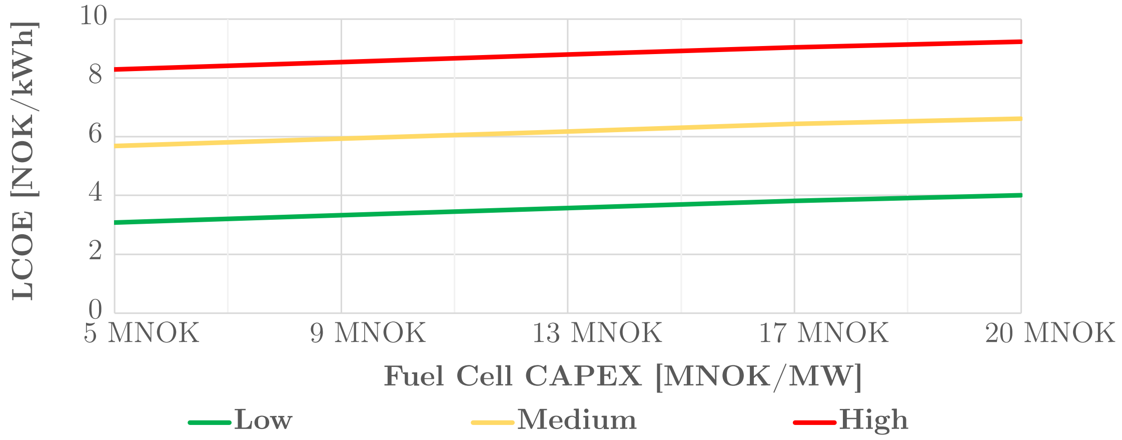

Figure 49: LCOE values with changes in fuel cell CAPEX for three different LCOH alternatives.

on the calculated LCOH in this thesis. The high price of 110 NOK/kg is included to illustrate what would happen to the LCOE in case of an increasing LCOH.

Table 17 gives a more accurate picture regarding the change of parameters. The table illustrates the sensitivity of the LCOE based on the LCOH, ranging from 30 to 110 NOK/kg, and the fuel cell CAPEX, ranging from 5 to 20 MNOK/MW. The LCOH value is very dependent on scale, application and scope of delivery. This is the basis of the wide range of LCOH values.

Table 17: Sensitivity analysis of the LCOE based on changes in LCOH and fuel cell CAPEX.

		Levelised Cost of Hydrogen [NOK/kg]				
	NOK/kWh	30	50	70	90	110
Fuel Cell CAPEX [NOK/kW]	5000	3,08	4,38	5,68	6,99	8,29
	9000	3,32	4,63	5,93	7,24	8,54
	13000	3,57	4,88	6,18	7,48	8,79
	17000	3,82	5,12	6,43	7,73	9,04
	20000	4,01	5,31	6,61	7,92	9,22

Table 17 shows that the LCOE varies with changes in both CAPEX and LCOH. However, from the sensitivity analysis, it becomes clear that the LCOE is most sensitive to the price of hydrogen. This is because smaller changes in hydrogen price affect the LCOE more than smaller changes in CAPEX. This makes sense, as the total cost of hydrogen represents 75% of the total costs, total OPEX and CAPEX, of the fuel cell system.

7.5 Cost Comparison to Grid Upgrades

In this section, the total costs of the grid infrastructure upgrade compared to the implementation of the PEMFC system will be presented. The costs of implementation will be essential when evaluating the competitiveness of the hydrogen solution.

In table 18, the costs of the different alternatives for grid upgrades are presented. The different upgrade alternatives are the same as mentioned in section 6.1.

Table 18: Prices of the different alternatives of grid infrastructure upgrades. Prices in the table are CPI adjusted from 2017 prices to 2022 prices.

Cost of Grid Upgrade
Alternative 1: 145 - 195 MNOK
Alternative 2: 144 - 181 MNOK
Alternative 3: 165 - 226 MNOK

The prices for the grid upgrade alternatives range from 144 to 226 MNOK. These prices represent solutions with lifetimes of more than 60 years. The prices were provided by Tensio for the year 2017 and have been CPI-adjusted using a CPI calculator to fit the year 2022 [137]. The adjusted numbers are presented in table 18.

For comparison, table 19 presents the total price of the fuel cell implementation. The first price is based on the current hydrogen price of 71.0 NOK/kg conducted in this thesis. As mentioned in section 3.2, hydrogen solutions are currently quite dependent on subsidies in order to be economically competitive. Enova is an example of an organisation that might be able to provide subsidies for a pilot project of this sort. For the scenario including subsidies granted from Enova, it is assumed that Enova can reduce the CAPEX by 45% the first year [7]. The total price of a fuel cell implementation with subsidies from Enova is presented as the second price in table 19.

Table 19: Prices of implementing the fuel cell with and without subsidies from Enova.

Cost of FC Implementation
Current H_2 price scenario: **210 MNOK**
H_2 price with Enova Subsidies: **175 MNOK**

Table 19 shows that with the current price of hydrogen at 71.0 NOK/kg, the total cost of the hydrogen solution lies within the high-end region of the total grid upgrade costs. However, the price of fuel cell implementation represents a solution with a lifetime of only 15 years. The difference in expected lifetime makes it challenging to compare the hydrogen and the grid upgrade solutions. This will further be discussed in section 8.6.2. With subsidies from Enova, the price can be reduced to 175 MNOK, being in the middle region of the price range for the grid upgrades.

7.6 Cost Comparison to Diesel Genset

The LCOE of the fuel cell system will be compared to a diesel genset for a competitiveness analysis. For this purpose, an existing LCOE conducted from Ballard for Cummins' model QSK60-G7 is used, as mentioned in section 6.5. The LCOE from Ballard has been modified to take the Norwegian diesel price, rather than the American price, into account. The Norwegian diesel price was set to the current price of 15.75 NOK/L, excluding VTA and road usage tax. [135]

The LCOE of the diesel genset was estimated to be approximately 5.3 NOK/kWh. This price is based on the LCOE Ballard conducted, the only modifications being the American Diesel price is changed to the Norwegian price. The LCOE of the diesel genset is compared to the LCOE of the fuel cell system. This comparison is shown in figure 50.

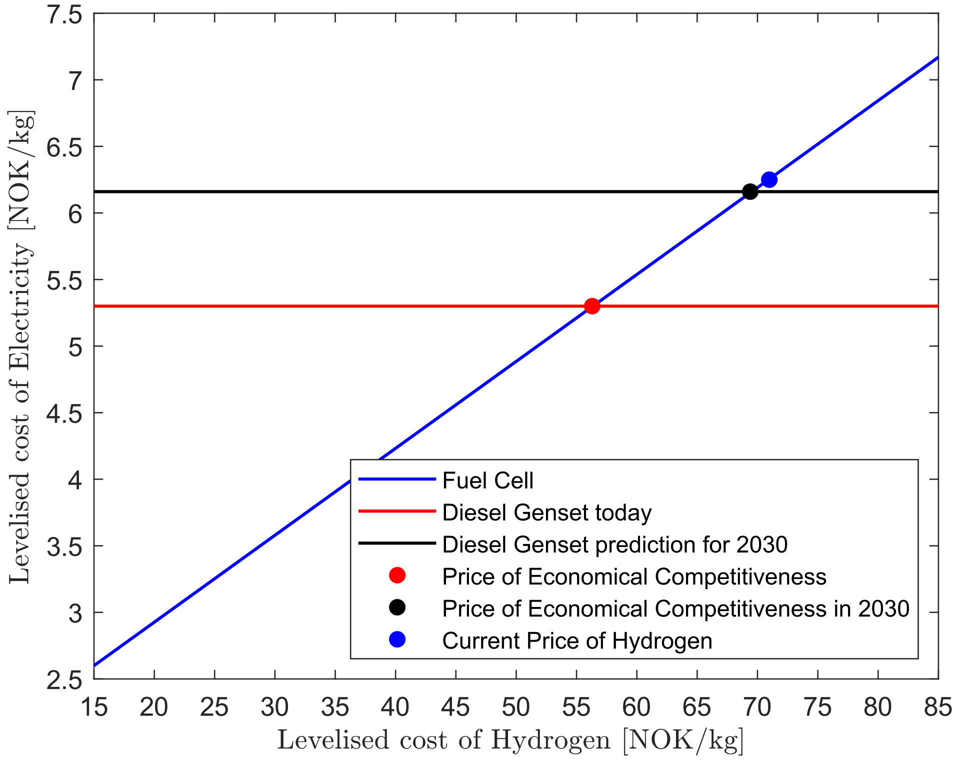

Figure 50: Comparison of LCOE from Fuel Cell System and Diesel Genset

Figure 50 shows the LCOE for the fuel cell system compared to the LCOE for the diesel genset. The graph illustrates how far the current price of hydrogen is economically competitive with diesel. This graphical representation does not take environmental aspects into account and is purely based on the prices of hydrogen and diesel. For the price of diesel, VAT and road usage tax are excluded. The LCOE for the diesel genset is conducted for 2022 and 2030. Further, the 2030 prices for diesel are higher as the carbon taxes are assumed to rise from 590 NOK/tonnes$_{CO_2}$ to 2000 NOK/tonnes$_{CO_2}$.

For hydrogen to become economically competitive in this simplified assumption, the price has to come down to around 56.3 NOK/kg$_{H_2}$ today. However, when increased carbon taxes for 2030 are included, the point of economic competitiveness becomes approximately 69.4 NOK/kg$_{H_2}$. This illustrates that the hydrogen price is not far off from being economically competitive with the predicted diesel price in 2030. Additionally, the price of hydrogen is likely to be reduced within this period. This may result in hydrogen becoming the preferred solution within a few years.

8 Discussion

This part of the project provides important notes and details regarding the method and results presented in the previous chapter. The discussion is an important part of examining the findings and the methods used to come up with the results. Doing this makes it possible to evaluate the different results in greater detail. It is also important to discuss the approach, as this would make it easier for further work and improvements of the results. The first part of the discussion includes the areas of focus and the limitations of the study. Furthermore, the method and result of the economics are evaluated, followed by a discussion of the competitiveness of hydrogen. Lastly, barriers and further work will be discussed.

8.1 Areas of Focus

The description of the thesis states that the electricity grid is the bottleneck to delivering necessary amounts of power in periods of high demand. Furthermore, the description states that this project would map out if a hydrogen stationary fuel cell system could be a financially and technically viable option compared to an expensive expansion of grid infrastructure. Both technical solutions are possible, but the economic aspect may limit which solution is beneficial.

Hydrogen could be investigated as a solution for several applications. As described in section 4.5, hydrogen can be used to run fuel cells in different types of stationary applications with different operational purposes. Several areas in the grid have problems during periods of high demand. This will require upgrades of the grid infrastructure or the implementation of new technologies in the grid. This thesis will evaluate one of the possibilities of implementing a fuel cell system in the grid.

To limit the workload, this study was based on one specific area provided by Tensio. The area of interest had limitations in the grid capacity, as elaborated in section 6.1, as local industries wanted an expansion of their production. Roughly estimated, the amount of hydrogen supply from Meråker could be used in a fuel cell system to help solve issues with voltage drops on the grid. In the early stages of choosing the area of focus, the load profile at Sørli was not given. Consequently, production and consumption were not seen in relation to each other at this stage. This will be discussed in greater detail in section 8.4. Anyhow, by looking into one area, it would be possible to analyse the chosen location in greater detail. The problems in the area provided by Tensio are not unique. Hence, the findings from this area can be used as a base case for other cost evaluations regarding grid upgrades.

Calculating the LCOH is the starting point in this thesis for estimating the total price for the hydrogen solution. The findings from the LCOH could potentially be used for different applications and in other areas with a few adjustments. This study presents the technology and components needed to design a hydrogen solution. Available technology, together with limitations provided by NTE, have set the framework for the methodology and choice of components. This will be discussed in greater detail in section 8.2.

The findings from the LCOH and costs of components for the fuel cell system are used to conduct a LCOE for the generated electricity delivered to the grid. The LCOE is used to calculate the total price of using the chosen fuel cell system, with the given hydrogen supply from Meråker, for this specific area of focus.

8.1.1 Available Supply of Hydrogen

The focus of this study regarding hydrogen production is on a PEMEC. Other electrolyser technologies and production methods for hydrogen are described in chapter 3. However, it was chosen to only consider the production of green hydrogen from a PEMEC in the calculations of this project.

The 1.25 MW PEMEC evaluated in this study can deliver approximately 500 kg of hydrogen per day. This amount of hydrogen aligns with the prerequisites NTE set for this project. However, this amount of hydrogen does not consider the local demand at the industrial site evaluated in this project. For an optimal solution, the production must be seen in relation to the local demand and consumption. As presented in section 7.2, the local demand varies significantly from season to season, from week to week, and from day to day. This makes the system much more complex than first anticipated. Daily delivery of 500 kg of hydrogen would be a limitation that is not comprehensible with the demand at the industrial site in specific periods of the year.

As presented in figure 41 in section 7.2, the highest daily demand of hydrogen is 1400 kg. This is much higher than what the evaluated PEMEC can deliver each day. This would require hydrogen storage. There is little to no demand for hydrogen during the summer at the industrial site. Because of this, different solutions need to be considered to find an optimal solution between production and local consumption. This will be discussed in greater detail in section 8.4.

8.2 Components

The system evaluated in this study is complex, with many different components. Each component affects the total price and the system operation of the hydrogen solution evaluated in this study. Therefore, it is important to evaluate and discuss the choices of the different components. In the theory part, several technologies have been mentioned. In this section, the choice of each component will be presented and discussed.

8.2.1 Electrolyser

For this project, the PEM electrolysis was given as a prerequisite by NTE. Still, there are other options to consider, as presented in section 3.4.2. The AEMEC and SOEC are yet to be proven at scale. Meaning they are evaluated not to be compatible for this project. If the technologies are commercialised, they can be important for the hydrogen industry in the future. If so, the SOEC would still probably not be compatible with this project because of the high operating temperature. If the AEMEC was to be commercialised, it would probably be a good option for this project due to its cheap material cost and high current densities.

The only competing water electrolysis technology today is the AEC. As presented in section 3.4.2, the AEC is the most mature and successful electrolysis method to date. Further, the alkaline environment makes the AEC cheaper than a PEMEC. On the other hand, there are some advantages with the PEMEC compared to the AEC. The PEMEC is more suitable for intermittent renewable energy, as PEM electrolysers are more adaptable to variable energy supply. Another advantage is the area of the plant, as the PEM electrolyser only needs a fraction of space compared to the AEC. The chosen electrolyser is containerised. Hence, it is very compact and area effective. Regardless, if there is no area limitation and a stable electricity supply, an AEC could be beneficial.

Choice of Electrolyser Model

The electrolyser evaluated in this thesis is based on the specifications of the MC250 PEMEC from Nel. This was chosen because it fits the requirements of NTE regarding hydrogen production. The MC250 has a max production capacity of 531 kg_{H_2}/day, which was close to the requirement of 500 kg/day. The MC250 also has the advantage of being small and portable, as it comes in containers. Table C.1 in appendix C shows that several manufacturers can deliver PEM electrolysers that fit the prerequisites given for this project. These alternative models have not been used for further reference in this thesis.

The hydrogen from a PEM electrolyser can be produced at high pressures. The hydrogen needs to be transported between the production and consumption facilities. Consequently, the hydrogen needs to be stored in vessels at 350 bar. The compression of hydrogen is very energy consuming. As a result, pressurised hydrogen out from the electrolyser could be beneficial. However, as presented in section 3.5 and 6.3.2, a PEM electrolyser operating at a pressure of 350 bar would be very expensive due to the need of pressure resistant materials. The MC250 has a delivery pressure of 30 barg. The output pressure of 30 barg would save energy while not needing expensive pressure-resistant materials. The amount of energy saved is on a logarithmic scale. Hence, it is beneficial to deliver as high as possible output pressure without the need for additional expensive materials.

8.2.2 Compression

The compression of hydrogen is complex because of its small molecular structure. As the MC250 operates with delivery pressure at 30 barg, the compressor needs to compress hydrogen from 30 barg to 350 bar. As mentioned in section 6.3.2, a compressor from Howden is chosen because of the cooperation agreement between Nel and Howden signed in 2021. The frame agreement is non-exclusive, which means that other competing manufactures may supply the MC250 electrolysis system with a compressor. This is not investigated further, as Howden's compressors have been operated in similar cases. In addition, Howden produce and deliver compressors that fit the designed system operation. Hence, the compressor is assumed to be constructed to compress 20.8 kg of hydrogen each hour from

30 barg to 350 bar.

Efficiency of the Compressor

The efficiency of the compressor was set to 93%. There are some uncertainties related to this efficiency. This will affect the overall price to some extent. As presented in section 6.3.2, the energy consumption for producing hydrogen rises from 50.0 kWh/kg$_{H_2}$ to 53.8 kWh/kg$_{H_2}$ with an compressor efficiency of 93%. The power consumption per kg of hydrogen produced will increase with lower efficiencies. As a result, more electricity is consumed during the production process. This would affect the overall electricity consumption.

8.2.3 Storage and Transport

Different storage technologies have been looked into and elaborated on in section 3.7. The advantages and disadvantages of the different technologies must be compared to select a suitable storage method. As presented in figure 17, the choice of storage method is highly dependent on the transport and distribution of hydrogen. The figure illustrates that transport of compressed gas with tube trailer is less competitive than other transport methods when the distance of transport increases. However, transport by trailers is the simplest method regarding infrastructure requirements. Tube trailers can transport hydrogen as both liquid and gas. Which of these options that is most competitive needs to be seen in relation to the production volume and the local demand.

The advantage of liquid hydrogen compared to compressed hydrogen is the volumetric density. This is presented in figure 15. However, 40% of the energy content can be lost in the liquefaction process. On the other hand, compressed hydrogen has a loss of around 10%. Large production volumes and transport distances would be required for liquid hydrogen to be the preferred storage method. In such cases, with large production volumes and transport distances, liquid hydrogen is competitive with compressed hydrogen [78].

The transport distance and volume in this study are evaluated as too short and too low for liquid hydrogen to be cost competitive compared to compressed hydrogen. Meraker Hydrogen will focus on compressed hydrogen, making it relevant to consider this method in this pilot project. Other storage methods, such as solid-state storage, are still not fully commercialised and need further research and technological development. As a result, solid-state storage is considered not competitive for the near future. Based on the information mentioned, compressed hydrogen is the selected storage method.

There are several opportunities for compressed hydrogen storage. The low energy density of hydrogen requires high pressures or extremely large storage vessels. Storage in salt caverns would be a cost-effective way to store large amounts of hydrogen. No such alternative is available in the area evaluated in this project. In addition, the hydrogen needs to be transported from the production site to the industrial site. Storage vessels that can be transported are required in this case. The most cost-effective way of storage would be to fill the vessels used for transport directly.

As elaborated in section 3.9, the system weight is of great importance when compressed hydrogen is transported by tube trailers. Composite vessels can handle larger amounts of hydrogen at higher pressures than vessels composed of steel. As a result, containers with composite vessels are evaluated to be the most convenient and cost-effective way of transport for this study.

The storage pressure evaluated in this thesis is 350 bar. Higher pressures are not considered in this thesis. This is a result of the prerequisites given by NTE. However, the composite vessels used in this thesis can handle pressures up to 1000 bar. By increasing the pressure, larger amounts of hydrogen can be transported. Due to lack of time, the effect this would have on the system is not considered. This should be evaluated in further work.

8.2.4 Fuel Cell System

The fuel cell system is one of the primary sources of uncertainty in this thesis. Therefore, the low-temperature PEMFC stationary system has been chosen for evaluation. The PEMFC was mainly chosen because of its technological maturity, enhancing the possibility of finding the required technical and operational data needed.

The PEMFC being a cold temperature fuel cell meant that when investigating the implementation of a fuel cell system into the grid, the cold temperature fuel cell system would offer fast ramp up and down. At this stage, the load profiles of the grid where the system would be implemented were unknown. This means a cold-temperature fuel cell would be more flexible than a high-temperature fuel cell system needing hours to ramp up from 0-100%. If the operation profile of the system fluctuated a lot, this would be a convenient feature for the fuel cell system to have. When compared to the other low temp fuel cell systems, the PEMFC is the one that has been utilised in MW scale facilities, as figure 24 in section 4.5 shows.

Available Data

As mentioned, the PEMFC system was mainly chosen due to its technological maturity. However, updated information within the MW scale of stationary fuel cell applications is highly limited due to market competitiveness. There were also limited publications on pilot projects implementing fuel cell systems for a similar cost analysis. For this reason, operation and cost data had to be collected and assembled from two different fuel cell models. The cost and operation data was gathered from Ballard's models ClearGen and ClearGen II.

These two models were both dimensioned for 1 MW but can be scaled up with increments of 500 kW. This meant that these systems would be able to meet the demand in the grid implementations of interest. Both of these models are a bit old, however, they are still utilised for similar purposes today. The cost data for the fuel cell system was mostly gathered for the ClearGen II. Most of the operation data is from the ClearGen model, as the ClearGen II model lacked some of the required information. Table 7 in section 6.3.2 presents the technical data for the two models.

Fuel Cell Efficiency

The electric efficiency of the fuel cell system will be an important parameter in the cost analysis of the implemented system. In this thesis, the electric efficiency is one of the operation parameters gathered from Ballard's ClearGen system. The data collected for this specific fuel cell system is from 2011, meaning the efficiency may have improved. Still, the efficiency published for the ClearGen model in 2011 of 46% (LHV) was used, in short of a more updated fuel cell model specification. The newer models of fuel cell systems from Ballard have efficiencies between 50-60% [103]. However, Ballard have not published the prices of these models, which are required to evaluate these models. Improvement of the efficiency of the system would make a significant difference to the amount of hydrogen needed for the fuel cell system operation.

8.3 Data Processing and Analysis

The data processing and the analysis of the obtained data are important to consider when evaluating the credibility of the results. The data in this section is primarily found from the literature review and not from actual manufacturers. Actual manufacturers are used whenever possible. However, different manufacturers can operate with different data and prices than those presented here. In addition, different manufacturers can offer different solutions for the same applications. As a consequence, results can vary depending on which manufacturers are used. Nevertheless, the data obtained from manufacturers in this thesis was in the same order of magnitude as data obtained from the literature review.

Furthermore, results depend on how the data is analysed. This applies to the analysis of cost data, as well as the analysis of power and electricity. There are different methods available to execute the analyses. Experts disagree on what methods are best to use. This is especially the case for the economic analyses. Discussion regarding the different methods will be presented in the following sections.

8.3.1 Discussion Related to Cost Data

The economic data collected for this thesis is mainly from the literature review. For the electrolysis and compression, data has been provided by NTE. Literature reviews are the basis for the collected data for the fuel cell system, hydrogen storage, and transport. In supplement to the literature review, there have been completed several meetings with people of relevant knowledge in the field of hydrogen. Still, there have not been provided actual offers from any manufacturers. Consequently, the cost data in this thesis is merely an estimate to use for reference. Different manufacturers may provide several of the components to the system for various prices.

As presented in section 6.4, the costs are divided by all the components in the hydrogen system. The cost data in the section is divided into different categories. These are primarily CAPEX and OPEX. All expenses can be divided between one of these two categories. For the LCOH, this is summarised in table 11 and 12 in section 7.3.

In section 6.4, the expenses are listed and described for each component. This is a comprehensive way to present the cost data included in the LCOH and LCOE calculations. It also makes it possible to analyse how changing prices for one component affect the total price. This is ideal if one or more numbers need to be replaced later in case of mistakes. By presenting the values under each component, it will also be possible to determine if certain numbers are missing out.

As mentioned, cost data is obtained from literature reviews or market participants. This does not eliminate the chance for errors. In some cases, assumptions are needed for the data to be comparable with the rest of the analysis. This especially applies for section 6.4.6, *other costs*, which consist of building and administration costs.

The prices collected and used in this study are all chosen conservatively and lay at the high end of the scale. This will undoubtedly result in high-end LCOH and LCOE prices, thus leading to a high total price for the hydrogen solution. The following sections will discuss how the prices collected for the different components affect the total price.

Electrolyser

For this study, the cost data for the electrolyser is based on a commercial electrolyser. Because of the competitiveness in the market, specific prices are not possible to obtain. For this study, the electrolyser CAPEX ranges from \$1500/kW to \$2000/kW. This value is based on full installation, including the cost of the rectifier, MV input, and transformer. Other sources operate with completely different CAPEX values. In most cases, it is not given which parts are included or not. IEA presents prices between \$1100/kW and \$1800/kW as possible ranges of electrolyser CAPEX. This is given with no further explanation of what is included in the price or not. Sources presented in section 3.4.2 presented prices between 1700€/kW and 2500€/kW. Even though such ranges can be useful to get an overview of the magnitude of the electrolyser CAPEX, much more accurate prices are needed to predict a more realistic hydrogen price. A conservative approach was chosen when gathering cost data for this thesis, resulting in the high-end electrolyser cost of \$2000/kW.

Electricity Costs, Grid Tariffs and Water Costs

Electricity costs, grid tariffs and water costs are previously presented in section 6.4.3. These expenses affect the total price of the hydrogen solution. For this study, water and electricity expenses are only included for the electrolyser and compressor. For the other components, it is not taken into consideration. This is because of the uncertainties connected to these expenses for the remaining components. The fuel cell needs cooling and heating during periods. It is difficult to evaluate to which extent this is needed. Consequently, these expenses are left out of the fuel cell prices.

Electricity and water costs primarily depend on the production rate of hydrogen. A high production rate increases the consumption of water and electricity. The operating profile of the electrolysis system is difficult to anticipate. Hence, these costs will probably deviate from prices in reality.

The water cost is based on a consumption of 10 L/kg produced hydrogen for the electrolyser. The price of water is provided by NTE and is assumed to be representative of prices in Meråker. NTE also provided the consumption of water for electrolysis. The price used for calculations is 0.348 NOK/m^3. It is not known if this price is in the high- or low-end of the price scale. The same applies to the water consumption for cooling. The water consumption for cooling is estimated at 100 m^3/day for a facility producing 500 kg hydrogen per day. The use of an estimate might result in small errors. However, water costs have little to no effect on the overall prices. Small changes in this price would not affect the total price of the hydrogen solution.

Electricity prices and grid tariffs are provided by NTE and Tensio. In this thesis, the price of electricity is assumed to be constant. In reality, the price of electricity may vary a lot over the lifetime of the system. The price of hydrogen is highly affected by the price of electricity. For this reason, a sensitivity analysis is conducted for the LCOH to illustrate the impact of changing electricity prices. Cases where the electricity price increases should be considered, as this would affect the hydrogen price negatively. There are uncertainties about how the electricity price will change, resulting in an assumption of a fixed electricity price being used. The fixed prices presented in Appendix C are used as a basis for the calculations.

Compressor

The compressor price is based on a price of 8400 NOK/kg/h of compressed hydrogen. Prices for compressors for hydrogen have been difficult to obtain from manufacturers and literature reviews. As a consequence, the assumed price of 8400 NOK/kg/h has been difficult to compare with other prices. This increases the chance of the price not representing the actual market price. However, the price is provided by NTE and assumed to be sufficient for this thesis.

The total price of the compressor is based on how much hydrogen the compressor needs to compress each hour. Since the production is set to 500 kg_{H_2}/day, the compressor is dimensioned to compress 20.8 kg_{H_2}/h. This is the average compression rate per hour. This assumption is evaluated to be suitable for this study. However, it is difficult to say whether this represents how an actual compressor would work or not. Prices will probably differ for a compressor dimensioned for this specific case compared to the estimation used in this thesis.

In addition, there are uncertainties regarding how the electrolyser will operate. The cost of the compressor is affected by the electrolyser operation. In this thesis, the electrolyser is assumed to have a constant production rate. If this is not the case, the average value of 20.8 kg_{H_2}/h is no longer representative of the dimensioning of the compressor. This will affect the total compressor price. Nevertheless, the compressor price is relatively low compared to the overall expenditures. Hence, small errors in the compressor price have little effect on the LCOH or the LCOE calculations.

Storage and Transport

Market participants provide cost data regarding storage and transport. When it comes to the storage method, the application for where it will be used limits the options. Meraker Hydrogen will produce compressed hydrogen at 350 bar. Transport of hydrogen with tube trailers is, as described earlier, the most cost-efficient and convenient way of transporting low to medium amounts of compressed hydrogen. Both steel and composite vessels can be used to store compressed hydrogen. However, after discussions with Hexagon Purus, composite vessels are the only realistic opportunity when transport is taken into account. This is because of the importance of weight.

For a stationary application, where no transport is needed, steel vessels could be a reasonable choice. When transport is included, the steel vessels will limit the amount of hydrogen that can be transported. As a consequence, the cost of transport would increase. This would, according to Hexagon Purus, result in a higher total cost for storage and transport.

The CAPEX of the composite vessels used in the calculations is 600€/kg. This is a key number used by Hexagon Purus. Similar numbers are found through the literature review. This number is assumed to be credible. Hexagon Purus also provided an OPEX. The safety regulations for storage vessels are very strict. As a result, vessels that pass relevant tests have, according to Hexagon, no limited lifetime. However, some OPEX is needed. An OPEX of 10% every tenth year is used to take security inspections and maintenance into account.

The cost of transport is provided by Andersen & Mørck AS. The credibility of this information is high, as Andersen & Mørck is a market participant. They were willing to provide an estimated cost for transport. The estimate used for the calculations is 10 kNOK. This price includes transport both ways. The estimate is based on a given example, with a distance of 300 km one way. This is close to the exact transport distance between production and delivery site. The small difference of a few kilometres is assumed to not affect the total price. However, prices might differ slightly in reality. Prices for road tolls and diesel are included. These prices might vary over a season. This can affect the total price. In addition, Andersen & Mørck is based in southern parts of Norway. A local carrier company from Trøndelag might operate with other prices. A local company should be contacted if possible to give an exact price for transport between the production site and the point of delivery. However, prices from Andersen & Mørck are assumed to be suitable for this study.

Fuel Cell

The fuel cell costs used for this thesis are based on the costs of the ClearGen II fuel cell system from Ballard. One of the main reasons why this model was chosen is, as mentioned, the insufficient economic data on other MW-sized fuel cell systems. For this specific model, the CAPEX of $1500K/MW was used as well as an OPEX of $0.022/kWh, as presented in section 6.4.5. This data has been published by Ballard themselves in a presentation given to the Energy Department of California in 2021 [133]. Although difficult to confirm, this was evaluated as a credible source as there was highly lacking data for comparison. Consequently, these are costs that are bound to a considerable amount of uncertainty. Aside from the fuel cell itself, there are some additional costs, also presented in section 6.4.5. The additional costs are stack replacement for the fuel cell system and the cost of the transformer.

The stack replacement costs of between \$240/kW to \$550/kW were found through literature review and are not directly provided from the ClearGen II fuel cell system from Ballard. Consequently, this is only a rough estimate. Once again, a conservative cost approach was chosen, resulting in \$550/kW being used. The stack replacement is assumed to occur every 15 000 operational hours throughout the lifetime of the system. This results in approximately three stack replacements for the fuel cell system during a lifetime of 15 years. The conservative approach may have resulted in a higher cost than what could be expected, which again affects the price of the LCOE.

Transformer

To connect the fuel cell to the grid, a transformer is needed. The transformer cost was provided by Tensio, within the range of 500 000 - 750 000 NOK. Yet again, the higher-end price was chosen.

In reality, transformers have some losses. However, transformers operate with very high efficiencies. These losses are not accounted for in this thesis, as they would have little to no effect on the total price.

Other Costs

Lacking other information, the NVE-model presented in section 6.4.6 is used to find these costs. The model from NVE is general and can be used to calculate the costs for several different technologies.

Assessment of such data will always be fraught with uncertainty. The uncertainties are linked to fluctuations in the market and site-specific conditions. Site-specific conditions can highly affect investment costs. For new technologies with limited experience, the uncertainty is even more significant. In the case of hydrogen, the experience is little compared to other technologies. This makes it difficult to evaluate whether the model from NVE is suitable for the application considered in this study.

In addition, NVE do not provide information about the size of the facilities that the model is based on. After discussions with several experts in the field of hydrogen, it is reasonable to assume that the fuel cell system evaluated in this thesis will be containerised. This will significantly reduce the cost of building and administration. However, the model from NVE is used as a result of lacking information. To what extent this will affect the price of *other costs* is unknown. As a consequence, it must be taken into account that the actual cost of these expenses will deviate from reality.

Exchange Rates and Inflation

The impact of different currencies and exchange rates is presented in section 6.4.1. The first intention was to base the exchange rates on average values over the last five years. This was to avoid those periods with large deviations from the average values affecting the prices. The current exchange rates are used, as this is assumed to be more reasonable. The reason is that the current exchange rates are of interest when considering an investment, not an average value. In addition, the current exchange rates have been relatively stable in recent years, except during the global pandemic. Consequently, the current exchange rates are assumed to be suitable for this study. The exchange rates of April 1, 2022, is used. By using this value, it will also be easier to keep control of the actual exchange rate.

Meraker Hydrogen is not expected to start production of hydrogen before 2024. However, this project is based on a start in 2022. As a result, prices might differ when the project starts. The same applies to the exchange rates. Changes in exchange rates will affect the total system price. This entails some uncertainty in the calculations. In addition, inflation is not included in the calculations. This leads to further uncertainties regarding the calculations.

8.3.2 Discussion Related to Power and Electricity Data

In addition to calculating the costs of a hydrogen solution, this thesis evaluates whether this solution is technically viable or not. Consequently, the power and electricity data must be evaluated in great detail. Tensio wanted to look at the opportunity for a hydrogen solution to support the grid in Sørli. Power and electricity data were provided for this area.

Estimating the New Demand

The hydrogen solution is intended to help the existing grid cope with the increased demand of 1 MW. There was not provided an estimated load profile after expansion from Tensio, meaning this had to be simulated. The future load profile is necessary to evaluate how the hydrogen solution needs to operate to cover the future demand. Hence, a load profile is estimated in this study based on the current consumption and a future expansion of 1 MW. The estimated load profile is presented in figure 39 in section 7.1. To estimate the new load profile, it is assumed that the peak consumption today will increase by 1 MWh. This is assumed to be 100%. All values were converted to a percentage of the maximal value. These values were multiplied with the new maximal value. This gives the load profile presented in figure 39.

It is several ways to estimate the new load profile. What all methods have in common is that they probably will deviate from reality. There is no guarantee that the load profile will have the same shape over a year after an expansion. The figures in appendix A illustrates how the consumption changes from year to year and from season to season.

Yearly Variations

Seasonal variations affect the load profile. Yearly variations can be related to temperatures and consumer changes in operation. Figure 54 in appendix A shows the combined consumption for consumer 1 and 2 between 2019 and 2022. As illustrated in the figure, the energy demand in 2020 was significantly lower compared to 2019 and 2021. This is probably a result of the temperatures in 2020. These yearly variations make it problematic to base the load profile on one year, as temperatures in 2022 probably will differ from previous years. The data from Tensio should ideally have been temperature corrected to represent the yearly variations better. However, this was not done in this thesis.

In addition, by basing the load profile on one year, operational exceptions might affect the load profile not representative of the rest of the operation. This is illustrated in figure 53 in appendix A. As seen in the figure, the downtime for consumer 2 is considerably longer for 2021 compared to both 2019 and 2020. The simulated load profile in this thesis is based on 2021. As a result, this simulation might not represent the actual and average operation of consumer 2.

Limiting the System to Two Consumers

It is important to note that the Nordli transformer station, presented in section 6.2.1, delivers electricity to a larger amount of consumers than what is evaluated in this thesis. Sørli is only one of several outputs from the Nordli transformer station. In addition, other consumers are located in Sørli, not just the two consumers evaluated in this thesis. In section 6.2.5, the fuel cell system was evaluated to solve the issues of voltage drops by covering parts of the demand from the combined consumers 1 and 2. This is a considerable simplification, as many other consumers also will affect the grid connection between Nordli and Sørli. However, as these two consumers have the biggest energy consumption, this simplification is assumed to be sufficient.

The previous sections illustrate the uncertainties connected to the load profile presented in this thesis. Despite this, the simulated load profile can be used to suggest how the fuel cell system will have to operate to solve the grid problems in Sørli.

8.4 Analysis of Energy Consumption and Hydrogen Demand

The energy consumption for the different periods during the year is essential to how the fuel cell system will operate. As the electrolyser has a production of 500 kg_{H_2}/day and the hydrogen demand highly varies during the year, there will be periods of complication concerning hydrogen distribution. In the following sections, the hydrogen demand for the different periods of the year is analysed in greater detail.

8.4.1 Season Variations and Effect on Hydrogen Demand

In section 6.2.1, the energy consumption from the consumers connected to Nordli transformer station is displayed in figure 27. This figure can be used to estimate available power on the grid for the industries at Sørli. As presented in section 6.2.5, there are problems delivering the required voltage and power quality when the energy consumption at Nordli Transformer station is at its peak. The peak demand occurs during the winter. For lower demands, there is sufficient available power on the grid. The information presented in section 6.2 can be used to calculate the new demand, which further can be used to calculate the hydrogen demand.

Average Hydrogen Demand after Expansion

In section 7.1 the new demand for the industries has been added, together with a max capacity line. The max capacity line has been used to estimate the amount of energy needed from the fuel cell system. The average amount of energy needed from the fuel cell system has been estimated to 6.1 MWh/day. This is equivalent to an average hydrogen consumption of approximately 400 kg_{H_2}/day. Because of the uncertainties of how much power is available on the grid, it is impossible to know exactly when and how much energy a fuel cell will have to deliver to the grid. The variation in hydrogen demand is presented in figures 41, 43 and 45 in section 7.2. This illustrates the significant variations from day to day and from season to season. As a result of the variations in consumption, the average hydrogen consumption is not representative of how the fuel cell system will work.

Actual Hydrogen Demand After Expansion

As described in the previous section, the hydrogen demand varies significantly from day to day and over a year. This is also explained in section 7.2. The week with the highest demand illustrates the problem of using average estimates. In this case, the peak hydrogen demand is more than three times the average demand. This results in some issues with the setup and operation of the system.

First and foremost, the electrolyser only can produce 500 kg_{H_2}/day. This results in issues during the high-demand weeks, like the one displayed in figure 41. The week of highest demand needs more than 6000 kg of hydrogen during the first five days of the week. An electrolyser, with a production capacity of 500 kg_{H_2}/day, can produce 2500 kg of hydrogen in the same period. This means that the system needs a storage capacity of more than 3500 kg on-site to supply the fuel cell with sufficient fuel. The system is based on two vessels with a total capacity of 1000 kg. Consequently, there is not sufficient storage capacity to cover this week.

In figure 35, the week following the week of highest demand is presented. Some of the days during this week have a higher demand than 500 kg_{H_2} /day. For only these two weeks combined, the total demand is over 12 000 kg. Consequently, higher storage capacities are needed during the winter months than what is accounted for in the calculations. This is the case in all periods where energy demand exceeds production capacity. This will affect the CAPEX for storage. In longer periods, especially in winter, there is a demand for a much higher storage capacity than what the calculations have taken into account. In addition, the OPEX is calculated as a percentage of CAPEX. As a result, the OPEX will increase significantly. This results in an increasing overall system price.

Moreover, an electrolyser with a higher production capacity may be more suitable for this case. Mainly because of the high storage capacity needed if hydrogen is stored prequel to the winter season. An electrolyser with higher capacity would make it possible to produce sufficient hydrogen for high-demand days. In this case, more trucks could be used to deliver a sufficient amount of hydrogen each day. This option could be cheaper than gradually having a huge amount of storage capacity built up in periods of low demand. A comparison between two systems like this, one with a higher production rate and one with a lower, could be part of further work with the project.

Perspective of Operation

The changing electricity demand affects the consumption of hydrogen. In this study, the consumption of hydrogen is evaluated daily. From a production perspective, this is a good way to illustrate the relation between supply and demand. However, the hourly values are of greatest interest from a grid operator's perspective. For this study, the fuel cell is evaluated daily. In the same way as the hydrogen demand.

This study does not consider how momentary changes in load affect the fuel cell operation. In reality, the efficiency of the fuel cell changes with the load. This is illustrated in figure 21. Major load changes will also affect the lifetime of the fuel cell system. Due to lacking knowledge and the complexity this would entail, a fixed efficiency is assumed for all load profiles. This is a rough assumption. The optimal operating profile for the fuel cell should be considered in more detail in further work.

Optimal Operation of the System

The current regulations and laws for the grid must also be considered. As presented in section 2.1.3, the grid companies must be able to deliver 100% of the consumers' max capacity. Consequently, the grid has to be able to deliver 1 MW or more at all times for this case. Consequently, the system must have the capacity to deliver 24 MWh each day. This equals around 1565 kg hydrogen. Nevertheless, no data indicate that the grid needs to provide peak powers over long periods. Hence, it may be reasonable to discuss the current regulations, as they may be outdated regarding current energy production and changing consumption patterns.

Furthermore, this also means that the periods of lower demand when the hydrogen supply is larger than the hydrogen demand can be utilised to better the system operation.

As mentioned in the last section, the periods of lower demand can be used to store hydrogen for the months of high demand.

Moreover, in a case where the hydrogen production capacity exceeds the consumption rate, it could be beneficial to keep the hydrogen production running as the total price is dependent on production volume. This is an issue when the demand is low during summertime in Sørli. One way to solve this issue may be to deliver hydrogen to other companies during summertime. Hence, an industry or a company that needs more energy during the summer season than the winter season could be an option. Nevertheless, the capacity on the grid is higher during the summertime. Hence, the hydrogen would probably be more useful in the industry processes presented in section 3.2, rather than converted back to electricity for the grid.

8.5 Economic Assessment

Economic assessments of hydrogen form a significant part of this thesis. Economic assessments can be conducted in several ways, and there are many disputes concerning the right approach to evaluating finances. For this thesis, the levelised cost model was chosen to estimate the total cost of the hydrogen solution for the grid.

The levelised cost model was chosen as this could, quite simply, divide the costs of hydrogen distribution into production and utilisation. The LCOH would account for all costs from the hydrogen production at Meråker, to fully distributed hydrogen. The LCOE, on the other hand, would account for the cost of the electricity generated from this hydrogen through a fuel cell system. Essentially, the LCOE could be conducted for a completely different fuel cell system in a completely different location. The only needed tweak really being the distance the hydrogen would have to be transported. With this approach, it was possible to separate supplier and buyer, which means more focus areas could have been evaluated if there had been more time.

The LCOH and LCOE equations are both quite simplified, which causes some uncertainties. First of all, it is assumed in all calculations that the CAPEX is paid in its entirety in the first year. This is usually never the case from a business perspective. The CAPEX should, in reality, be paid in installments over a set period. The LCOH and LCOE calculations do not take into account potential loans and interests the investors may have obtained from a bank. Secondly, the OPEX is assumed to be fixed running expenses in both calculations, meaning the amount is assumed to be the same each year when discounting is excluded. These running expenses will, in reality, be variable and may fluctuate during the lifetime.

8.5.1 LCOH

For the LCOH, it was chosen to account for all the distribution stages of hydrogen production, meaning that compression, storage, and transport are seen as part of the production process. This will naturally contribute to the price of hydrogen being higher compared to only evaluating the cost of production from electrolysis. The prerequisites of production amount at Meråker are also factors that drive the price of hydrogen up. It is important to remember that the price of hydrogen conducted in this LCOH analysis results from these limiting parameters. Consequently, the prices will differ from other hydrogen market prices. These aspects will be discussed in this section and are the main reasons why the price of hydrogen conducted in this thesis is high.

The total CAPEX and OPEX for the production and distribution stages are shown in tables 11 and 12 in section 7.3. For the CAPEX, the total price came to 37.5 MNOK, in which the electrolyser CAPEX is about half. Figure 46 shows how the CAPEX is divided between the different components. *Other costs*, which includes building and administration costs, is the second highest expense. There was no specific data for these expenses, and an estimation from NVE conducted on a general basis for thermal plants was used. Building plot costs may differ in different regions and for different plants, making this a rough estimate. Despite the uncertainty regarding *other costs*, the model from NVE gives a useful overview of the possible magnitude of these costs. The storage costs were also interesting, accounting for 14% of the total CAPEX. This shows how expensive the storage of hydrogen can be.

The total OPEX is 86.6 MNOK. Electricity costs are the largest, as expected. This is mainly because of the electricity consumption needed to run the electrolysis plant.

Transport is the second largest operational expense, resulting from the long distance between the production and the fuel cell site. This cost may be quite a lot smaller for other areas of utilisation closer to the production site. Further, as mentioned in section 3.9, Greensight's analysis shows that transporting hydrogen with trailers for over 2.5 hours is not cost-effective. The distance between the production and utilisation sites exceeds this and is one of the reasons for the high transport cost.

The electrolysis OPEX is also quite large, mainly because of the stack replacement needed after 10 years. This, however, is a one-time expense, in comparison to electricity and transport, which has to be paid for every year.

Based on the results and the discussion in section 8.4, the expenses for storage may prove to be too low. The periods with the highest demand would require significantly higher storage capacities than what is taken into account in the calculations. This would highly affect the CAPEX for storage. This could potentially increase the price of hydrogen.

Lifetime

The lifetime of the electrolyser plant is set to 15 years. The cell stacks will need to be replaced during this time, which happens after 10 years. The stack replacement cost is 40% of the CAPEX of the electrolyser. As the replaced stack will only be operated for another 5 years before the end of the lifetime, this is an expense which is not much value for money. Therefore, an increased lifetime of the electrolyser to 20 years would improve the value of this investment a great deal.

Discount Rate

For the LCOH, a discount rate of 6% is chosen as this is the rate NTE operate with. The discount rate highly affects the LCOH, and for further reference, there should be made a comparison between different rates. However, this has not been done in this thesis.

Electricity Price and Grid Rental Fee

Electricity price is one of the main parameters affecting the price of the LCOH, and for this reason, a sensitivity analysis was conducted for different electricity prices. The sensitivity analysis is presented in figure 48 in section 7.3. The electricity price used in this LCOH is 300 NOK/MWh. However, changes in electricity prices will affect the price of hydrogen significantly. In this thesis, it is assumed that the electrolysis plant has received a fixed price of electricity. This is assumed to not change over the lifetime of the system. This is, of course, an assumption of high uncertainty. How the electricity price will change in the future, with new technology and more implementation of intermittent renewable energy sources, is difficult to predict. The sensitivity analysis shows how, in the worst case, the hydrogen price may exceed 100 NOK/kg with an electricity price of 0.85 NOK/kWh. This is way too expensive to be economically competitive with other fuels today. On the other hand, lower electricity prices may push the price of hydrogen towards 60 NOK/kg, in resemblance making the hydrogen price more competitive.

The total yearly grid rental fee of 1.04 MNOK is also assumed to be constant over the electrolysers lifetime. As for the electricity price, a fixed price is an assumption of high uncertainty. However, the grid rental fee is usually less variable than the electricity price. Consequently, changes in the grid rental fee are less important than changing electricity prices.

Production Volume of Hydrogen

It is well known that production volume is a key cost driver when it comes to hydrogen production through electrolysis. For this project, the electrolyser is of size 1.25 MW. This results in approximately 500 kg of hydrogen production per day. This is a small-scale production volume and will consequently mean the price of the hydrogen produced is higher compared to large-scale production volumes.

As elaborated in section 3.2.1, production volume and economies of scale is important for the cost reduction of hydrogen. In this study, production is not seen in the context of economies of scale. This study evaluates the hydrogen needed to cover the demand at one specific location. Dimensioning a production rate to account for one location with relatively small demand is not cost-effective. Low production volume in combination with long transport distances results in higher prices of hydrogen. If several locations and a higher demand were evaluated, the production could be increased, and the hydrogen price could be reduced. This is further elaborated in section 8.6

8.5.2 LCOE

The LCOH is a part of the LCOE. For this study, the LCOE calculates the price of the electricity generated by the fuel cell system.

The price of hydrogen is used as the fuel price for the fuel cell system. Additional costs contributing to the LCOE are the CAPEX and OPEX of the fuel cell system and the transformer needed to step up the voltage from the fuel cell. It is important to note the importance of the LCOH for the LCOE. As discussed, the LCOH is on the high end of the scale. This is also the case for the data collected for the LCOE. Consequently, the LCOE will also represent a high price. This will be further elaborated on in this section, together with other aspects that affect the LCOE.

Table 15 and 16 in section 7.4 show how the CAPEX and OPEX is divided by different shares. The total CAPEX came to 18.4 MNOK. The fuel cell CAPEX is the major contributor to the total CAPEX. *Other costs* is the second highest expense. The transformer is a small share of the total CAPEX. Similar to the LCOH, the share of *other costs* is based on the model from NVE. Tensio wants a fuel cell system that can be relocated in case of changing energy demands. Experts on stationary fuel cells have confirmed that the fuel cell system can be containerised, making the system portable. This would significantly reduce the need for building and administration costs.

Consequently, the share of *other costs* may be too high. A reduction of this share would positively affect the total price of the hydrogen solution. However, the significance of this share is reduced when the OPEX is taken into account.

For the OPEX, the total price is 118 MNOK over 15 years. This is significantly higher than the total CAPEX. The cost of hydrogen is the largest expense, with a share of 86%. This is expected due to the high hydrogen price and a large amount of hydrogen needed to run the fuel cell system.

For this study, the LCOH and LCOE are conducted separately. By doing this, it is possible to separate supplier and buyer. The hydrogen is purchased at the LCOH price. Hence it is an OPEX in the LCOE, as hydrogen must be purchased to produce electricity. The LCOE is based on the assumption that an amount of the produced hydrogen is purchased. In addition, stack replacement is needed regularly, contributing to a significant OPEX. This is assumed to happen every third year. The hydrogen, however, has to be paid for every year.

As expected, based on the hydrogen price, the LCOE is high. For this study, the LCOE was calculated to **6.25 NOK/kWh**. This is in line with the observations in table 17 and figure 49 presented in section 7.4, conducted through a sensitivity analysis. It can be observed that the hydrogen price is the major contributor to the LCOE. At a lower hydrogen price, the LCOE significantly decreases. The economics can be illustrated with an example. A 10% reduction of hydrogen price would reduce the price of the LCOE by 7%, which further reduces the total price of the hydrogen solution by almost 7%. This shows how important it is to keep hydrogen prices at a low level. Future hydrogen prices are assumed to decrease from current levels. This will increase the chance of a hydrogen solution being competitive.

Lifetime

The lifetime of the fuel cell system is set to 15 years. Fuel cell manufacturers often operate with lifetimes up to 20 years. However, 15 years is chosen for the LCOH and the LCOE to be conducted on an equal basis. The stack lifetime is 15 000 operational hours. With the current load profile, this is equivalent to a stack replacement every third year.

Discount rate

As for the LCOH, a discount rate of 6% is chosen for the LCOE. Most of the expenses regarding the LCOE are operational and not one time expenses, meaning the discount rate highly affects the LCOE.

Hydrogen price

If the study was conducted on the basis of a higher production volume and a higher number of customers, the price of hydrogen would decrease. Currently, the demand is too low for a higher production rate. For further reference, a total future demand should be mapped out. This will map out whether there is a market for increased hydrogen production. This will also make it possible to present a hydrogen price which is more competitive than the one presented in this study.

The assumption of a constant price of hydrogen in the LCOE is a simplification. This is not representative for the future price development of hydrogen. A decrease in hydrogen price should be included to increase the credibility of the results. However, the future price development is difficult to anticipate. Hence, it is excluded from this study.

8.6 Competitiveness of Hydrogen

As described in section 3.2, the competitiveness of hydrogen highly depends on the ambitions to reduce global warming. This is a result of the widespread recognition of green hydrogen as a key contributor in order to achieve the ambitions of the Paris Agreement. Future estimates are based on a cost reduction through a combination of learning rates, technological improvements, and economies of scale. However, several measures are already available which can contribute to increasing the competitiveness of the hydrogen solution evaluated in this thesis. This includes larger-scale supply and reducing the cost of transport. In addition, there are other aspects than only the purely economical that should be considered when comparing the competitiveness of two alternative solutions.

8.6.1 Larger Scale Supply of Hydrogen

One of the main limitations of this thesis is the 500 kg production of hydrogen each day. As presented in section 3.2, the limit of 500 kg is a consequence of the fact that hydrogen, as an energy carrier, has a relatively small market to date. In addition, the production volume is assumed to only cover the two consumers in Sørli, meaning 500 kg_{H_2}/day is a sufficient amount for this thesis.

Larger production facilities will contribute to economies of scale. This will reduce the cost of producing hydrogen. However, for a larger production volume to be economically favourable, there must also be a demand for an increasing amount of produced hydrogen. As of today, this is not the case. On the other hand, hydrogen is seen as an important contributor to achieving the ambitions of limiting global warming. It is projected that this will increase the future demand for hydrogen significantly, as presented in section 3.2.1. This will eventually reduce the prices of producing hydrogen. Increasing demand will lead to technological development, which will lower the prices of the relevant technologies. Hydrogen Council suggest that scaling up electrolysis to 70 GW will lead to electrolyser prices of $400/kW. This is a price that is significantly lower than the price evaluated in this thesis, illustrating how economies of scale may affect the competitiveness of hydrogen.

8.6.2 Comparing Hydrogen and a Conventional Grid Solution

In section 7.5, the total price of the different possibilities of grid infrastructure upgrades was presented in comparison to what the total fuel cell system would cost. Clearly presented in tables 18 and 19, the hydrogen fuel cell solution is a high-end cost alternative. There are, however, possibilities for driving the price down. Subsidies are one of such possibilities for a price reduction. For this thesis, the only means for subsidies investigated were from Enova.

Furthermore, in the evaluation of the hydrogen price conducted in this thesis, there are other aspects which may drive the price towards economic competitiveness. As mentioned in section 8.5.1, the transported distance in this thesis results in a high hydrogen price. By disregarding the cost of transport, the hydrogen price would be reduced by nearly 30%. One way to improve the competitiveness of a similar hydrogen solution may therefore be to have the production facility closer to the fuel cell facility. This is in line with the finding from Greensight, concerning the duration of transport over 2.5 hours not being cost-competitive.

On the other hand, defining cost competitiveness is quite difficult, as there is such a big difference in the lifetime and operational features of the two different solutions. When only considering the economic aspects and the lifetime, it is clear that the grid upgrade alternative is the preferred alternative. However, there are other aspects than only purely economic which should be taken into account when comparing the competitiveness of two alternative solutions.

Flexibility in Planning

First and foremost, as several sectors are decarbonised and electrified in the following years, similar problems as evaluated in this thesis will occur on the grid more frequently. In every instance this occurs, there has to be evaluated whether or not the grid should be upgraded in the specific area. One of the issues with grid upgrades is that the grid always has to be dimensioned to cover the peaks of demand, resulting in many instances of over dimensioning. This can, in many cases, lead to quite large expenses. Moreover, when the grid infrastructure upgrade is made, this facility has a lifetime of more than 60 years.

Using the example of industrial expansion as a reason for the increased demand on the grid, there will be instances where the industry shuts down within this time, potentially resulting in the demand going away. In comparison, the fuel cell system would provide a much more flexible solution to meeting the increased demand of this sort. Firstly, the fuel cell system has a much shorter lifetime of 15 years, meaning there could be made new evaluations concerning the demand at the end of every life cycle. If the demand was to go away, the fuel cell system could simply be moved to another location.

Another mean of flexibility that favours the fuel cell system solution is how scaleable it is. The ClearGen fuel cell systems from Ballard can be scaled in increments of 500 kW, meaning tailored solutions for each case of implementation is possible. On the other hand, upgrades on the grid operate with specific standards of power lines and are a lot less flexible. However, if the demand was to increase a lot within the lifetime of 60 years, there may be issues of the grid having to be upgraded a second time. This would again lead to new costs of infrastructure upgrades on the grid.

Flexibility of Electricity Generation

Finally, the hydrogen fuel cell system has the valuable ability to generate electricity only when needed. The fuel cell will only generate electricity as long as it is fed with fuel, whereas the grid has to deliver energy as soon as it is produced. The fuel cell operation can, for this reason, be integrated quite well into the grid and deliver electricity in periods of low capacity on the grid.

One of the barriers to utilising this ability to the fullest is the cost of long-term hydrogen storage, which today is very expensive. In addition, the amount of electricity generated from the fuel cell system is not equal to the amount of electricity consumed when producing hydrogen. The different components, from electrolyser to fuel cell system, have different efficiencies which propagate, meaning the total electric efficiency is very low. The electrolyser has an efficiency of 67%, the compressor efficiency of 93%, and the fuel cell system an efficiency of 46%. The total electric efficiency of the system ends up at only 29%. Consequently, the feature of flexible energy availability pays the price of a low total electric efficiency.

Another limiting barrier to the implementation of a fuel cell system is the lack of suitable regulations. As of today, there are no regulations in which new technologies used in grid management can be implemented in a good way. This will be elaborated in section 8.7.

8.6.3 Other Possibilities for Hydrogen Utilisation

Some of the benefits a fuel cell system could provide on the grid were presented in the last section. However, the current price may be a significant constraint to further technological and economic development. As briefly mentioned in section 4.5, one of the first steps for the technological rollout of hydrogen stationary fuel applications may be exchanging diesel gensets for backup power solutions.

Fuel cell systems provide the same technological operation possibilities as the diesel genset, in addition to being a zero-emission alternative. There are, therefore, several prospects for decarbonising facilities that are dependent on backup power solutions. Hospitals and data centers are examples of such facilities where a hydrogen fuel cell system could replace a diesel genset.

Replacing Diesel Gensets

In section 7.6 the LCOE of a diesel genset compared to the LCOE of hydrogen was presented. For the hydrogen production evaluated in this thesis, there is still a need for considerable cost reduction in order to be economically competitive with diesel. However, as mentioned earlier, the price of hydrogen conducted in this thesis is assumed to have possibilities of price reduction. Moreover, the price of diesel is expected to increase simultaneously as carbon taxes increase, meaning the point of economic competitiveness will shift.

Figure 50 in section 7.6 shows an estimated future price for diesel based on an increase in carbon tax suggested by the Norwegian government in 2021. For the future diesel price scenario, the price of hydrogen calculated in this study is already close to being economically competitive. In addition, since the price of hydrogen is likely to be reduced within 2030, hydrogen can be a competitive solution for diesel gensets.

In contemplation, an interesting comparative study would have been to implement a similar fuel cell system to backup power for a data center. The competitiveness of hydrogen compared to a diesel genset is an interesting starting point in evaluating the competitiveness of hydrogen. This could be a starting point for technological commercialisation for larger fuel cell systems.

8.6.4 Future Price Development

As described in section 3.2.1, the future price development of hydrogen is difficult to project. However, there is a rapid growing interest for hydrogen. This is a result of the increasing number of ambitious decarbonisation targets. The use of hydrogen is now seen as critical if these targets are to be achieved. This increasing interest in hydrogen is a key cost driver for reducing hydrogen prices. Investments are already made and new projects are announced, such as Meraker Hydrogen. Despite this, most projects still are at a pre-commercial phase, with limited capacity. Several reports point out the need for further investments to achieve the 2050-ambitions.

As elaborated in section 3.2.1, it is a broad range of possible future hydrogen demands. This is connected to the ambitions regarding decarbonisation. The higher ambitions see a higher growth in future demand. Furthermore, the development in demand is affected significantly by the future price development. This illustrates the interconnection between development in demand and price development.

The challenge for hydrogen is to develop infrastructure in parallel with the growing demand. Developing technological infrastructure will contribute to lower investment costs. This aspects would be cost drivers for future price reduction. This will enable uptake of hydrogen solutions in areas where it is not competitive today. In order to develop technological infrastructure in the start phase, there will be need for subsidies. Subsidies can help drive the price of hydrogen down to enable further implementation.

Whether hydrogen will be competitive or not highly depends on local conditions and available infrastructure. Available infrastructure is critical for the widespread uptake of hydrogen. Without this, the use of hydrogen would be limited to certain areas and the required deployment of hydrogen would not be achieved.

8.7 Barriers

Several barriers has to be overcome, in order for the widespread uptake of hydrogen. High production prices are an important barrier for the development of the hydrogen market. Price reduction is important for hydrogen to be competitive with other competing energy sources. These economical barriers have been discussed in detail in the previous sections. In addition to the economical barriers, there are also barriers related to politics and public opinion.

8.7.1 Political and Regulatory Barriers

As presented in section 2.1.2, current regulations make it challenging for grid companies to consider new technologies to supplement the grid. Regulations say that production and trading need to be carried out by separate companies. Consequently, an entity that produces and distributes electricity back to the grid can not be owned by Tensio. The fuel cell system evaluated in this thesis will operate this way. As a result, cooperation between a producer and Tensio is needed for this to be a solution to consider. This can present a problem for the implementation of hydrogen solutions in grid operations.

Another barrier that might be an issue is the grid regulations that state that every customer shall be able to use 100% of their capacity at any given time without limitations. Hence, the fuel cell needs to be able to cover peak demands from the grid consumers. These regulations will, in many cases, result in overdimensioning. They do not facilitate flexible and new solutions.

The political framework of today is based on previous assumptions of steady growth in demand. A forward-looking framework is important for the major uptake of hydrogen solutions. Policies need to facilitate the implementation of hydrogen strategies. This will remove barriers to further investments in hydrogen.

8.7.2 Public Opinion

The public opinion is fundamental for the implementation of hydrogen in the society. Unfortunately, the public awareness and knowledge of hydrogen and hydrogen technologies are relatively low compared to competing technologies.

The implementation of hydrogen must be done carefully, as failures in any project could damage the public perception severely. Challenges and risks should be discussed openly by authorities, as this would increase the public awareness of this technology. Furthermore, it should be an ambition to increase the public knowledge of hydrogen technologies. This would be vital for public acceptance of hydrogen, as well as for further reduction in the public use of fossil fuels.

8.8 Further work

This thesis was written for the duration of one semester at NTNU, meaning the scope of the thesis had to be limited. There are some aspects of the project that have not been evaluated to the degree they should have due to limited time. In this section, these aspects will be discussed briefly. There will also be provided some suggestions for further work that can be done in order to supplement the findings in this thesis.

More Customers and Larger Scale of Production

First and foremost, it was decided to only evaluate one case study for the implementation of a fuel cell system to solve problems on the grid. This was solemnly due to the limited time. Ideally, more areas of focus should have been evaluated in order to be able to discover some general considerations when implementing a stationary fuel cell system for power generation to the grid. It would have been of high interest to compare different case studies to conduct which limitations and prerequisites affect the cost of such an implementation the most. Moreover, it would have been interesting to compare the different LCOE prices for the different case studies, to investigate what the best starting point for such a fuel cell system would be.

For such an analysis, it would be possible to assume a large-scale production volume of hydrogen from Meråker, and assume that the entire production volume could be distributed between several customers. Consequently, a more competitive price of hydrogen could be evaluated in each case study. This would provide an indication of which areas of focus stationery fuel cell applications should have in the startup phase.

Consideration of Optimal Operation for the Fuel Cell System

As mentioned in the discussion, there has been made some simplifications and assumptions in the operational evaluation of the fuel cell system. In this thesis, it was assumed that the fuel cell system has an efficiency of 46% at all times. The fuel cell operation profile has been calculated by analysing the daily energy demand from the electrical grid, further estimating the amount of energy generation the fuel cell must provide, using the average efficiency. Mainly because of lacking knowledge, there has not been taken into account how momentary changes in the load profile may affect the operation and efficiency of the fuel cell system. The efficiency of a fuel cell system would, in reality, be highly dependent on the load and will differ for low and high loads.

For a grid company like Tensio, the hourly changes of load in the grid are what is of interest, and moreso also, how the fuel cell system would operate based on different momentary loads on the grid. For further work, it would be interesting to investigate in detail how the fuel cell system would operate in regard to the complexity of a changing grid capacity.

For this thesis, it is assumed that the fuel cell system operates in a linear fashion, whereas the grid covers the momentary fluctuations. For further work, it would be interesting to analyse how an off-grid fuel cell system in combination with another energy storage technology would operate to cover fluctuations in the load. If a battery was chosen, it could be discharged when sudden peak loads on the grid occur and are charged when the load profile is relatively stable. In this respect, the fuel cell system would be operated in a similar linear fashion, which could be dimensioned around the point of ideal operation. The battery would then be operated in the same manner as the grid does for the case evaluated in this thesis. This aspect would be interesting to evaluate further but has not been done in this thesis due to lacking knowledge and limited time.

In addition to the above-mentioned, the optimal operation regarding production and consumption is only briefly discussed in this thesis. Due to the variations in hydrogen demand over a year, the production and consumption of hydrogen should be evaluated in greater detail to find an optimal way to operate the system. An example is by combining the system with other industries. Such possibilities should be evaluated in greater detail in further work with this project.

Contacting Market Manufacturers

The costs of every input and output in the LCOH and LCOE affect the total cost of the implemented fuel cell system. In this thesis, most of the collected cost data is derived from literature reviews and is consequently linked to some uncertainty. In some instances, if missing specific data, manufacturers have been contacted in an attempt to gather this information. Otherwise, assumptions have been made. Ideally, all the data should have been collected from manufacturers, in this manner lowering the chances of cost errors. This has not been done in this thesis and may well not be easily completed as marked manufacturers often want to keep their information secret. However, with sufficient time to arrange the right meetings, it is possible to retrieve some information, as experienced in this project. This approach would have been used to a larger degree if there had been more time.

Conclusion

The objective of this thesis is to evaluate the competitiveness of a hydrogen solution compared to a grid infrastructure upgrade. As a consequence, this thesis evaluates the current and future competitiveness of hydrogen. In addition, the thesis aims to describe how a fuel cell system can contribute to solving power-related grid problems. These aspects appear through the research question, which states:

Is the integration of a hydrogen solution for solving power-related grid problems competitive compared to an upgrade of the grid infrastructure?

The methodology presents the approach for answering the thesis statement. First, the current energy demand for the area where the fuel cell system is implemented is presented. This is done to simulate a possible future load profile in order to estimate the operational profile of the fuel cell system. The fuel cell system is assumed to operate in periods when the energy demand exceeds the grid capacity. These periods cause power-related problems on the grid.

Further, all the components needed for a hydrogen solution, and their costs, are presented. The data are primarily collected from literature reviews. Some information is obtained from NTE and other relevant companies. These costs are used for the economic analyses in this thesis. The total cost of a hydrogen solution is based on a calculated LCOH and a LCOE.

The LCOH consists of production, compression, storage, and transport of hydrogen as it is the fully distributed hydrogen that is of interest for the customers. The electrolyser produces 500 kg_{H_2}/day. A 1.25 MW PEM electrolyser is needed to produce this amount of hydrogen. The hydrogen is stored in compressed hydrogen vessels. The vessels need to be transported from the production site in Meråker to Sørli.

The LCOH is used to calculate a LCOE. The LCOE calculations consist of the costs for the fuel cell components, the transformer, and the cost of hydrogen. The LCOE represents the price of the electricity generated from the fuel cell to supplement the grid. The total CAPEX and OPEX of the hydrogen solution are used to calculate a total price of the hydrogen solution. This price is compared to the price of upgrading the grid infrastructure in order to evaluate competitiveness.

With a discount rate of 6% and an expected lifetime of 15 years, the LCOH is calculated to be 71.0 NOK/kg_{H_2}. The LCOH after production and compression is calculated to 47.5 NOK/kg_{H_2}. When hydrogen storage is included, the price becomes 51.0 NOK/kg_{H_2}. Transport solely contribute to 20.0 NOK/kg_{H_2}, bringing the price to 71.0 NOK/kg_{H_2}. With this LCOH price, the LCOE is calculated to be 6.25 NOK/kWh. This gives a total price of 210 MNOK for the hydrogen solution. It is important to note that there are some uncertainties related to the cost data collected in this thesis. Consequently, the total price of the system is somewhat uncertain. However, the calculated LCOH and LCOE are in the same order of magnitude as prices found in literature reviews. Hence, it is concluded that the total price of 210 MNOK is comparable to the cost of a grid infrastructure upgrade.

For the specific case study conducted in this thesis, the price of the hydrogen solution is in the high-end region of the grid infrastructure upgrade cost. In addition, the life expectancy of the fuel cell system is 15 years, compared to more than 60 years life expectancy for the grid upgrade solution. With this in mind, the fuel cell system is not competitive compared to upgrading the grid infrastructure.

Several factors indicate that the case study for Sørli might not be the best for evaluating the competitiveness of hydrogen. First and foremost, the transport distance between the production and fuel cell site is too long to be cost-effective. The price of the hydrogen before accounting for transport is 51.0 NOK/kg$_{H_2}$. This price is competitive compared to diesel. This illustrates the problem with evaluating locations far from the production site in the early phase of hydrogen implementation.

It can be concluded from this thesis, based on the economics, that a hydrogen solution is not competitive compared to a grid upgrade in Sørli at this point. With that said, the future potential of hydrogen is huge. Several barriers have to be overcome for the widespread uptake of hydrogen. A widespread uptake could potentially reduce the price of hydrogen and further increase the competitiveness of a hydrogen solution. However, other areas might already be competitive. Locations at a closer distance to the production site should be evaluated for further work, as it can be concluded that Sørli is not the optimal starting point for implementing a hydrogen solution.

References

[1] Hydrogen Council. *How hydrogen empowers the energy transition.* Hydrogen Council, Jan. 2017. URL: https://hydrogencouncil.com/wp-content/uploads/2017/06/Hydrogen-Council-Vision-Document.pdf (visited on 04/26/2022).

[2] IRENA. *Global Energy Transformation: A Roadmap to 2050.* International Renewable Energy Agency, 2018. URL: https://www.irena.org/-/media/Files/IRENA/Agency/Publication/2018/Apr/IRENA_Report_GET_2018.pdf (visited on 04/26/2022).

[3] International Energy Agency. *The Future of Hydrogen.* June 2019. URL: https://iea.blob.core.windows.net/assets/9e3a3493-b9a6-4b7d-b499-7ca48e357561/The_Future_of_Hydrogen.pdf (visited on 03/25/2022).

[4] Hydrogen Council. *Hydrogen Insights.* Feb. 2021. URL: https://hydrogencouncil.com/wp-content/uploads/2021/02/Hydrogen-Insights-2021-Report.pdf (visited on 05/10/2022).

[5] Geir Martin Bakken. *Economic Analysis.* Digital Meetings. May 13, 2022.

[6] Jørn Helge Dahl. *Hydrogen Storage and Composite Vessels.* Mar. 17, 2022.

[7] Knut Granlund. *Economic support from Enova.* Digital Meeting. May 11, 2022.

[8] Thomas Holm. *Hydrogen technologies and use areas for hydrogen.* Digital Meeting. Mar. 30, 2022.

[9] Daniel Janzen. *Economic Analysis.* Digital Meetings. Apr. 22, 2022.

[10] Fredrik S. Moen. *Meråker Hydrogen and Hydrogen Prices.* Personal Communication. May 10, 2022.

[11] Odd Moen. *Hydrogen and Electrolyser Market.* Meeting. Mar. 30, 2022.

[12] Steffen Møller-Holst. *Hydrogen technologies and use areas for hydrogen.* Digital Meeting. Mar. 31, 2022.

[13] Rune Paulsen. *Data from Tensio.* Meetings and E-mail. Apr. 27, 2022.

[14] Bjørn Simonsen. *Hydrogen and Electrolyser Market.* Digital Meeting. Mar. 30, 2022.

[15] Ronnie Smedsvik. *Costs of transport.* Communication by E-mail. Mar. 16, 2022.

[16] Energifakta Norge. *The electricity grid.* Apr. 9, 2019. URL: https://energifaktanorge.no/en/norsk-energiforsyning/kraftnett/ (visited on 04/28/2022).

[17] Statnett. *Slik fungerer kraftsystemet.* Oct. 19, 2018. URL: https://www.statnett.no/om-statnett/bli-bedre-kjent-med-statnett/slik-fungerer-kraftsystemet/ (visited on 04/28/2022).

[18] NVE. "The Norwegian power system. Grid connection and licensing". In: (Aug. 2018). URL: https://publikasjoner.nve.no/faktaark/2018/faktaark2018_03.pdf (visited on 04/28/2022).

[19] Knut A. Rosvold. *Krafttransformator.* Nov. 9, 2021. URL: http://snl.no/krafttransformator (visited on 04/28/2022).

[20] Electrical Classrom. *Why is electricity transmitted at high voltages?* Aug. 22, 2019. URL: https://www.electricalclassroom.com/why-is-electricity-transmitted-at-high-voltages/ (visited on 04/28/2022).

[21] Statnett. *Grid Development Plan and Power System Plan.* Feb. 11, 2018. URL: https://www.statnett.no/en/for-stakeholders-in-the-power-industry/o

ur-analyses-and-assessments/grid-development-plan-and-power-system-plan/ (visited on 05/01/2022).

[22] Statnett. *Hvordan få nettilknytning?* Jan. 7, 2022. URL: https://www.statnett.no/for-aktorer-i-kraftbransjen/nettkapasitet-til-produksjon-og-forbruk/dette-er-tilknytningsprosessen/ (visited on 05/02/2022).

[23] Statnett. *Tilgang til strømnettet.* URL: https://www.statnett.no/for-aktorer-i-kraftbransjen/nettkapasitet-til-produksjon-og-forbruk/ (visited on 05/02/2022).

[24] Energifakta Norge. *Regulation of grid operations.* Apr. 9, 2019. URL: https://energifaktanorge.no/en/regulation-of-the-energy-sector/regulering-av-nettvirksomhet/ (visited on 04/28/2022).

[25] Energiloven. *Lov om produksjon, omforming, overføring, omsetning, fordeling og bruk av energi m.m. (energiloven) - Kap. 3. Elektriske anlegg - Lovdata.* URL: https://lovdata.no/dokument/NL/lov/1990-06-29-50/KAPITTEL_3#%5C%C2%5C%A73-3 (visited on 04/28/2022).

[26] NVE. *Områdekonsesjon.* Aug. 2, 2021. URL: https://nve.no/konsesjon/konsesjonsbehandling-av-nettanlegg/omradekonsesjon/ (visited on 04/28/2022).

[27] NVE. *Konsesjonsbehandling av nettanlegg.* Jan. 17, 2022. URL: https://nve.no/konsesjon/konsesjonsbehandling-av-nettanlegg/ (visited on 04/28/2022).

[28] NVE. *Selskapsmessig og funksjonelt skille.* Feb. 17, 2022. URL: https://www.nve.no/reguleringsmyndigheten/regulering/nettvirksomhet/selskapsmessig-og-funksjonelt-skille/ (visited on 05/02/2022).

[29] Knut A. Rosvold. *Tensio AS.* July 6, 2021. URL: http://snl.no/Tensio_AS (visited on 05/02/2022).

[30] Statnett. *Connecting to the Norwegian power grid.* URL: https://www.statnett.no/en/for-stakeholders-in-the-power-industry/the-grid-connection-process/ (visited on 04/29/2022).

[31] NVE. *Network connection.* Dec. 14, 2021. URL: https://2021.nve.no/norwegian-energy-regulatory-authority/network-regulation/network-connection/ (visited on 04/29/2022).

[32] Anders Øie. *Her er de 5 strømregionene vi har i Norge.* Nov. 1, 2019. URL: https://xn--strm-ira.no/str%C3%B8mregioner-norge (visited on 05/02/2022).

[33] Ingunn Mjønerud. *Slik bestemmes dagens strømpris.* URL: https://xn--strm-ira.no/dagens-str%C3%B8mpris (visited on 04/29/2022).

[34] Energifakta Norge. *The power market.* Oct. 5, 2021. URL: https://energifaktanorge.no/en/norsk-energiforsyning/kraftmarkedet/ (visited on 04/29/2022).

[35] NVE. *Quality of electricity supply.* Sept. 7, 2021. URL: https://2021.nve.no/norwegian-energy-regulatory-authority/network-regulation/quality-of-electricity-supply/ (visited on 04/28/2022).

[36] NVE. *Spenningskvalitet.* Sept. 7, 2021. URL: https://www.nve.no/reguleringsmyndigheten/regulering/nettvirksomhet/leveringskvalitet/spenningskvalitet/ (visited on 04/28/2022).

[37] Sweco Norge AS. *Vurdering av behov for å sette grenseverdi for minimum kortslutningsytelse i lavspenningsnettet.* NVE, Nov. 3, 2015. URL: https://webfileser

vice.nve.no/API/PublishedFiles/Download/201501703/1613941 (visited on 04/29/2022).

[38] Statnett. *The steps in the grid connection process*. Nov. 27, 2018. URL: https://www.statnett.no/en/for-stakeholders-in-the-power-industry/the-grid-connection-process/the-steps-in-the-grid-connection-process/ (visited on 04/30/2022).

[39] International Energy Agency. *Electricity Market Report, July 2021*. July 14, 2021. URL: https://www.oecd-ilibrary.org/energy/electricity-market-report-july-2021_f4044a30-en (visited on 04/26/2022).

[40] Robert Steinberger-Wilckens et. al. *Hydrogen Fuels For Energy Security*. 2017. URL: https://discovery.ucl.ac.uk/id/eprint/10087005/6/Dodds_IMPJ5213-H2FC-Supergen-Energy-Security-032017-Chapter%5C%205.pdf (visited on 04/25/2022).

[41] Norwegian Ministry of Petroleum et al. *The Norwegian Government's hydrogen strategy*. URL: https://www.regjeringen.no/contentassets/8ffd54808d7e42e8bce81340b13b6b7d/hydrogenstrategien-engelsk.pdf (visited on 04/24/2022).

[42] Anmar Frangoul. *Russia's invasion has made energy security a hot topic. The U.S. thinks hydrogen could be the answer*. Mar. 28, 2022. URL: https://www.cnbc.com/2022/03/29/game-changing-hydrogen-could-play-a-big-role-in-the-energy-transition-.html (visited on 04/25/2022).

[43] Hydrogen Council and McKinsey & Company. *Hydrogen for Net-Zero*. Nov. 2021. URL: https://hydrogencouncil.com/wp-content/uploads/2021/11/Hydrogen-for-Net-Zero.pdf (visited on 04/25/2022).

[44] Thomas Briault. *When will hydrogen become a cost-competitive industry?* URL: https://www.arup.com/perspectives/when-will-hydrogen-become-a-cost-competitive-industry (visited on 04/26/2022).

[45] Centrica. *What is energy resilience?* URL: https://www.centricabusinesssolutions.com/us/blogpost/what-energy-resilience (visited on 05/02/2022).

[46] Hydrogen Forward. *How Hydrogen Supports Grid Resilience*. June 10, 2021. URL: https://www.hydrogenfwd.org/how-hydrogen-supports-grid-resilience/ (visited on 04/26/2022).

[47] U.S. Department of Energy. *Early Markets: Fuel Cells for Backup Power*. URL: https://www.energy.gov/sites/prod/files/2014/10/f19/ftco_early_mkts_fc_backup_power_fact_sheet.pdf (visited on 05/02/2022).

[48] IRENA. *Green Hydrogen: A Guide to Policy Making*. Nov. 2020. URL: https://www.irena.org/publications/2020/Nov/Green-hydrogen (visited on 04/25/2022).

[49] FuelCellsWorks. *History*. URL: https://fuelcellsworks.com/knowledge/history/ (visited on 05/03/2022).

[50] S. Shiva Kumar and V. Himabindu. "Hydrogen production by PEM water electrolysis - A review". In: *Materials Science for Energy Technologies* (Mar. 29, 2019). URL: https://www.sciencedirect.com/science/article/pii/S2589299119300035 (visited on 02/15/2022).

[51] Odne S. Burheim. *Engineering Energy Storage*. Academic Press, 2017.

[52] European Commission. *A Clean Planet for all A European strategic long-term vision for a prosperous, modern, competitive and climate neutral economy*. Nov. 28, 2018. URL: https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=CELEX:52018DC0773 (visited on 04/25/2022).

[53] International Energy Agency. *Global Hydrogen Review 2021*. Oct. 21, 2021. URL: https://www.oecd-ilibrary.org/energy/global-hydrogen-review-2021_39351842-en (visited on 04/25/2022).

[54] Acciona. *What is green hydrogen used for?* URL: https://www.activesustainability.com/sustainable-development/what-is-green-hydrogen-used-for/ (visited on 04/25/2022).

[55] Mathilde Carlier. *Hydrogen fuel cell vehicles worldwide 2020*. Apr. 6, 2022. URL: https://www.statista.com/statistics/1291480/hydrogen-fueled-road-vehicles-worldwide/ (visited on 04/26/2022).

[56] Markets and Markets. *Hydrogen Generation Market*. Feb. 2021. URL: https://www.marketsandmarkets.com/Market-Reports/hydrogen-generation-market-494.html (visited on 04/25/2022).

[57] IRENA. *Hydrogen Economy Hints at New Global Power Dynamics*. Jan. 15, 2022. URL: https://www.irena.org/newsroom/pressreleases/2022/Jan/Hydrogen-Economy-Hints-at-New-Global-Power-Dynamics (visited on 04/25/2022).

[58] World Energy Council. "Working Paper | Hydrogen Demand and Cost Dynamics". In: *Hydrogen on the Horizon: Ready, Almost Set, Go?* (Sept. 2021). URL: https://www.worldenergy.org/assets/downloads/Working_Paper_-_Hydrogen_Demand_And_Cost_Dynamics_-_September_2021.pdf?v=1634916141 (visited on 04/25/2022).

[59] Hydrogen Council. *Path to Hydrogen Competitiveness*. Jan. 20, 2020. URL: https://hydrogencouncil.com/wp-content/uploads/2020/01/Path-to-Hydrogen-Competitiveness_Full-Study-1.pdf (visited on 05/20/2022).

[60] Alejandro Barnett. *Hystar*. Aug. 2021. URL: https://hystar.com/.

[61] Kazunari Sasaki et al., eds. *Hydrogen Energy Engineering: A Japanese Perspective*. Green Energy and Technology. Springer Japan, 2016. DOI: 10.1007/978-4-431-56042-5. (Visited on 02/15/2022).

[62] Timothy E. Lipman and Adam Z. Weber. "Fuel Cells and Hydrogen Production: A Volume in the Encyclopedia of Sustainability Science and Technology, Second Edition". In: *Encyclopedia of Sustainability Science and Technology Series* (2019). URL: http://link.springer.com/10.1007/978-1-4939-7789-5 (visited on 03/10/2022).

[63] Alexandra Zablocki. *Fact Sheet | Energy Storage (2019)*. Feb. 22, 2019. URL: https://www.eesi.org/papers/view/energy-storage-2019 (visited on 03/01/2022).

[64] Claude Lamy & Pierre Millet. "Efficiency Coefficients of Water Electrolysis Cells". In: *Journal of Power Sources* (Jan. 31, 2020). URL: https://www.sciencedirect.com/science/article/abs/pii/S0378775319313436 (visited on 04/17/2022).

[65] IRENA. *Green hydrogen cost reduction: Scaling up electrolysers to meet the 1.5C climate goal*. URL: https://www.irena.org/-/media/Files/IRENA/Agency

/Publication/2020/Dec/IRENA_Green_hydrogen_cost_2020.pdf (visited on 03/10/2022).

[66] Yu Luo et al. "Bridging a bi-directional connection between electricity and fuels in hybrid multienergy systems". In: *Hybrid Systems and Multi-energy Networks for the Future Energy Internet* (2021). URL: https://www.sciencedirect.com/topics/engineering/electrolysis-cell (visited on 04/18/2022).

[67] S.A. Grigoriev et al. "Current status, research trends, and challenges in water electrolysis science and technology". In: *International Journal of Hydrogen Energy* (Oct. 2020). URL: https://www.sciencedirect.com/science/article/pii/S0360319920310715?casa_token=ZYuG5wY9NukAAAAA:CMscyB9eGWmFQvVULHyV40agiJtrBKuiCYiP4DbC680WWd6XDRBMqxVHQR7OXOzZ44Zdgbwu (visited on 04/21/2022).

[68] Immanuel Vincent and Dimitri Bessarabov. "Low cost hydrogen production by anion exchange membrane electrolysis". In: *Renewable and Sustainable Energy Reviews* (Jan. 2018). URL: https://reader.elsevier.com/reader/sd/pii/S1364032117309127?token=B53B1B17C2D67661609ED53333A460E63D246D881DB5553B408956DEA8F080653F23751F40C3E7AC071B2C229D47A8EB&originRegion=eu-west-1&originCreation=20220328123640 (visited on 03/28/2022).

[69] U.S. Department of Energy. *Gaseous Hydrogen Compression*. URL: https://www.energy.gov/eere/fuelcells/gaseous-hydrogen-compression (visited on 04/26/2022).

[70] Demaco. *The energy density of hydrogen: a unique property*. URL: https://demaco-cryogenics.com/blog/energy-density-of-hydrogen/ (visited on 04/26/2022).

[71] Hanna Langels and Oskar Syrjä. *Hydrogen Production and Storage Optimization based on Technical and Financial Conditions*. Feb. 3, 2021. (Visited on 03/01/2022).

[72] Hydrogen Council. *Hydrogen - Scaling Up*. Nov. 2019. URL: https://hydrogencouncil.com/wp-content/uploads/2017/11/Hydrogen-scaling-up-Hydrogen-Council.pdf (visited on 05/10/2022).

[73] Ramin Morradi and Katarina M. Groth. "Hydrogen storage and delivery: Review of the state of the art technologies and risk and reliability analysis". In: *International Journal of Hydrogen Energy* (May 3, 2019). URL: https://www.sciencedirect.com/science/article/pii/S0360319919309656 (visited on 02/15/2022).

[74] Andreas Züttel et al. "Hydrogen density in nanostructured carbon, metals and complex materials". In: *Materials Science and Engineering: B* 108.1 (Apr. 2004), pp. 9–18. URL: https://linkinghub.elsevier.com/retrieve/pii/S0921510703005270 (visited on 03/10/2022).

[75] I.A. Hassan et. al. "Hydrogen storage technologies for stationary and mobile applications: Review, analysis and perspectives". In: *Renewable and Sustainable Energy Reviews* (Oct. 2021). URL: https://www.sciencedirect.com/science/article/pii/S1364032121005980 (visited on 03/25/2022).

[76] H. Barthelemy et. al. "Hydrogen storage: Recent improvements and industrial perspectives". In: *International Journal of Hydrogen Energy* (Mar. 2017). URL: https:

//www.sciencedirect.com/science/article/pii/S0360319916305559 (visited on 02/15/2022).

[77] Demaco. *Liquid Hydrogen Storage*. URL: https://demaco-cryogenics.com/blog/liquid-hydrogen-storage/ (visited on 04/01/2021).

[78] Hydrogen and Fuel Cell Technologies Office. *Liquid Hydrogen Delivery*. URL: https://www.energy.gov/eere/fuelcells/liquid-hydrogen-delivery (visited on 03/28/2021).

[79] Sigrid Damman et al. *Largescale hydrogen production in Norway - possible transition pathways towards 2050*. 2020. URL: https://www.sintef.no/en/publications/publication/1794574/ (visited on 04/01/2022).

[80] Tim Hornyak. *An $11 trillion global hydrogen energy boom is coming. Here's what could trigger it*. Nov. 1, 2020. URL: https://www.cnbc.com/2020/11/01/how-salt-caverns-may-trigger-11-trillion-hydrogen-energy-boom-.html (visited on 05/05/2022).

[81] U.S. Department of Energy. *Hydrogen Delivery*. URL: https://www.energy.gov/eere/fuelcells/hydrogen-delivery (visited on 04/05/2022).

[82] Jørg Aarnes et al. *Produksjon og bruk av hydrogen i Norge*. Jan. 25, 2019. URL: https://www.regjeringen.no/contentassets/0762c0682ad04e6abd66a9555e7468df/hydrogen-i-norge---synteserapport.pdf (visited on 04/05/2022).

[83] Safety4Sea. *Kawasaki Heavy Industries: Hydrogen tanker project proves its feasibility*. Mar. 9, 2022. URL: https://safety4sea.com/kawasaki-heavy-industries-hydrogen-tanker-project-proves-its-feasibility/ (visited on 04/11/2022).

[84] Jonathan Saul. *Too cold to handle? Race is on to pioneer shipping of hydrogen*. May 11, 2021. URL: https://www.reuters.com/business/sustainable-business/too-cold-handle-race-is-pioneer-shipping-hydrogen-2021-05-11/ (visited on 04/05/2022).

[85] Amin Lahnaoui et al. "Optimizing hydrogen transportation system for mobility via compressed hydrogen trucks". In: *International Journal of Hydrogen Energy* (July 19, 2019). URL: https://www.sciencedirect.com/science/article/pii/S0360319918335171 (visited on 04/21/2022).

[86] Fornybar klyngen. *Veikart for hydrogen i Trøndelag*. Sluttrapport 2019. Jan. 9, 2020.

[87] L. Birek and S. Molitorys. *Hydrogen Fuel Cell Emergency Power System*. 2009. URL: https://skemman.is/bitstream/1946/7003/1/Stanislaw_Lech.pdf (visited on 02/21/2022).

[88] Norsk Hydrogenforum. *Hydrogen og sikkerhet*. URL: https://www.hydrogen.no/ressurser/hydrogen-og-sikkerhet (visited on 04/23/2022).

[89] Industrial Metallurgists. *Hydrogen Embrittlement of Steel*. Sept. 15, 2016. URL: https://www.imetllc.com/hydrogen-embrittlement-steel/ (visited on 04/25/2022).

[90] Michael Pfeifer. *An Introduction to Hydrogen Embrittlement*. Oct. 29, 2021. URL: https://www.corrosionpedia.com/an-introduction-to-hydrogen-embrittlement/2/2568 (visited on 04/25/2022).

[91] Sustainable Development French Ministry of Ecology Energy and Spatial Planning. *Accidentology Involving Hydrogen.* 2009. URL: https://www.aria.developpement-durable.gouv.fr/wp-content/files_mf/SY_hydrogen_GB_2009.pdf (visited on 04/25/2022).

[92] Gexcon AS. *Hydrogen hazards: too dangerous to handle? - Gexcon Blog.* URL: https://www.gexcon.com/blog/hydrogen-hazards-too-dangerous-to-handle/ (visited on 04/24/2022).

[93] DSB. *About DSB | Direktoratet for samfunnssikkerhet og beredskap.* URL: https://www.dsb.no/menyartikler/om-dsb/about-dsb/ (visited on 04/24/2022).

[94] R. Felseghi et al. "Hydrogen Fuel Cell Technology for the Sustainable Future of Stationary Applications". In: *Energies 2019* (Dec. 3, 2019). URL: https://www.mdpi.com/1996-1073/12/23/4593/htm (visited on 02/15/2022).

[95] Ryan O'Hayre et al. *Fuel Cell Fundamentals.* John Wiley & Sons, 2016.

[96] Viviana Cigolotti et. al. "Comprehensive Review on Fuel Cell Technology for Stationary Applications as Sustainable and Efficient Poly-Generation Energy Systems". In: *Energies 2021* (June 13, 2021). URL: https://www.mdpi.com/1996-1073/14/16/4963/htm (visited on 02/18/2022).

[97] HDF Industry. *Technology.* URL: https://www.hdf-industry.com/en/technology/.

[98] Mebius. *Fuel Cells.* URL: https://www.mebius.si/technology (visited on 05/20/2021).

[99] Winai Chanpenga and Yottana Khunatorn. "The effect of the input load current changed to a 1.2 kW PEMFC performance". In: *9th Eco-Energy and Materials Science and Engineering Symposium* (2011). URL: https://www.researchgate.net/publication/251712600_The_effect_of_the_input_load_current_changed_to_a_12_kW_PEMFC_performance (visited on 05/20/2022).

[100] James Larminie and Andrew Dicks, eds. *Fuel Cell Systems Explained.* John Wiley & Sons Ltd, 2003. DOI: TK2931.L372003621.31´2429âĂŞdc21. (Visited on 05/02/2022).

[101] Rob-Heng Lin et. al. "Toward a hydrogen society: Hydrogen and smart grid integration". In: *International Journal of Hydrogen Energy* (Aug. 2020). URL: https://reader.elsevier.com/reader/sd/pii/S0360319920301373?token=B34D16BF8558A327D69C91CDA5C3206DB2E7BA18E63FCE68897CCC4C07B79CA91EEBE0513582DDFBED58C75B34FB9DF0&originRegion=eu-west-1&originCreation=20220215080348 (visited on 02/15/2022).

[102] Carly Anderson. *Fuel Cells: Stationary Power.* URL: https://medium.com/prime-movers-lab/fuel-cells-everything-else-bbbad62333f9 (visited on 04/25/2022).

[103] Roy Segev. *Why Fuel Cells Are the Solution for Sustainable Data Centers.* Nov. 1, 2021. URL: https://blog.ballard.com/sustainable-data-centers (visited on 05/19/2022).

[104] The Fuel Cell and Hydrogen Energy Association. *Road Map to a US Hydrogen Economy Report.* URL: https://static1.squarespace.com/static/53ab1feee

4b0bef0179a1563/t/5e7ca9d6c8fb3629d399fe0c/1585228263363/Road+Map+to+a+US+Hydrogen+Economy+Full+Report.pdf (visited on 04/30/2022).

[105] Genevieve Saur et al. *Hydrogen and Fuel Cells for Data Center Applications Project Meeting: Work Shop Report*. URL: https://www.nrel.gov/docs/fy20osti/75355.pdf (visited on 04/24/2022).

[106] U.S Department of Energy. *Early Market Applications for Fuel Cell Technologies*. URL: https://www.energy.gov/eere/fuelcells/early-market-applications-fuel-cell-technologies#critical (visited on 04/30/2022).

[107] U.S Department of Energy. "Fuell Cells for Stationary Power Applications". In: (Oct. 2017). URL: https://www.energy.gov/sites/prod/files/2018/01/f46/fcto_fc_stationary_power_apps.pdf (visited on 04/30/2022).

[108] University of Bergen. *Levelized Cost of Energy/Electricity (LCOE)*. URL: https://mitt.uib.no/courses/4050/pages/5-dot-3-levelized-cost-of-energy-slash-electricity-lcoe (visited on 04/28/2022).

[109] Sean Ross. *CAPEX vs. OPEX: Whats the Difference*. Mar. 30, 2021. URL: https://www.investopedia.com/ask/answers/112814/whats-difference-between-capital-expenditures-capex-and-operational-expenditures-opex.asp (visited on 04/28/2022).

[110] Energy & Industrial Strategy Department for Business. *Hydrogen Production Costs 2021*. July 2021. URL: https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/1011506/Hydrogen_Production_Costs_2021.pdf (visited on 04/28/2022).

[111] Jason Fernando. *Net Present Value (NPV)*. Aug. 29, 2021. URL: https://www.investopedia.com/terms/n/npv.asp (visited on 05/16/2022).

[112] Adam Hayes. *Discount Rate*. July 29, 2021. URL: https://www.investopedia.com/terms/d/discountrate.asp (visited on 04/28/2022).

[113] Will Kenton. *Sensitivity Analysis*. Oct. 5, 2021. URL: https://www.investopedia.com/terms/s/sensitivityanalysis.asp (visited on 04/28/2022).

[114] NTE. *Strøm, Solceller, Elbillading, Internett og TV*. URL: https://nte.no/ (visited on 04/19/2022).

[115] Tensio. *Vi forsyner Trøndelag med strøm*. URL: https://tensio.no/ (visited on 04/19/2022).

[116] Nel Hydrogen. *Containerized PEM Electrolyser*. May 7, 2019. URL: https://nelhydrogen.com/product/m-series-containerized/ (visited on 04/19/2022).

[117] Nel ASA. *Nel ASA: Signs frame agreement with Howden for supply of hydrogen compressors*. URL: https://nelhydrogen.com/press-release/nel-asa-signs-frame-agreement-with-howden-for-supply-of-hydrogen-compressors/ (visited on 04/26/2022).

[118] Howden. *Howden supplying compression to Everfuel | Renewable Energy | Howden*. May 28, 2021. URL: https://www.howden.com/en-us/articles/renewables/green-team (visited on 04/26/2022).

[119] U.S. Department of Energy. *Types of Fuel Cells*. URL: https://www.energy.gov/eere/fuelcells/types-fuel-cells (visited on 04/23/2022).

[120] GenCell. *Comparing Fuel Cell Technologies*. URL: https://www.gencellenergy.com/news/comparing-fuel-cell-technologies/ (visited on 04/23/2022).

[121] Ballard. *Stationary Power Generation*. URL: https://www.ballard.com/fuel-cell-solutions/fuel-cell-power-products/backup-power-systems (visited on 02/25/2022).

[122] Ballard. *ClearGen™ Multi-MW Systems - Ballard - PDF Catalogs | Technical Documentation | Brochure*. URL: https://pdf.directindustry.com/pdf/ballard/cleargen-multi-mw-systems/22779-383697.html (visited on 04/23/2022).

[123] NPROXX. *Different Types of Pressure Vessel*. May 30, 2019. URL: https://www.nproxx.com/different-types-of-pressure-vessel/ (visited on 04/23/2022).

[124] Hexagon Purus. "Hydrogen distribution systems in standard execution". In: (June 2021). URL: https://s3.eu-central-1.amazonaws.com/hexagonpurus-website/X-Store_Container_complete_datasheet.pdf (visited on 04/23/2022).

[125] Xe. *US Dollar to Norwegian Krone Exchange Rate Chart | Xe*. URL: https://www.xe.com/currencycharts/?from=USD&to=NOK&view=5Y (visited on 04/19/2022).

[126] Investing.com. *GBP NOK Historical Data*. URL: https://www.investing.com/currencies/gbp-nok-historical-data (visited on 04/19/2022).

[127] Zohreh Jalili. *Information provided by NTE*. Digital Meetings. Feb. 25, 2022.

[128] SINTEF. *Komprimert Hydrogen Prisestimat*. Teamsopplastning. Jan. 25, 2021.

[129] Siemens. *Silyzer 300*. URL: https://assets.siemens-energy.com/siemens/assets/api/uuid:a193b68f-7ab4-4536-abe2-c23e01d0b526/datasheet-silyzer300.pdf (visited on 04/20/2022).

[130] Fornybar klyngen. *Klimavennlig utvikling av Kråkøya kysthavn og næringsområde*. Forprosjektrapport 2019. June 10, 2021.

[131] K. Reddi et al. "Techno-economic analysis of conventional and advanced high-pressure tube trailer configurations for compressed hydrogen gas transportation and refueling". In: *International Journal of Hydrogen Energy* (Mar. 1, 2018). URL: https://www.sciencedirect.com/science/article/pii/S0360319918300843 (visited on 04/21/2022).

[132] LMAS. *A Stack Cost Comparison of 100 kW Combined Heat and Power Fuel Cell Systems*. URL: http://lma.berkeley.edu/posters/A%5C%20Stack%5C%20Cost%5C%20Comparison%5C%20of%5C%20100%5C%20kW%5C%20Combined%5C%20Heat%5C%20and%5C%20Power%5C%20Fuel%5C%20Cell%5C%20Systems.pdf (visited on 05/04/2022).

[133] Roy T. Segev. *Large Stationary Fuel Cell Solutions*. Digital Meeting. Jan. 21, 2021.

[134] Karen Nybakke et al. *Kostnader i energisektoren*. Norges Vassdrags- og Energidirektorat, 2015. URL: https://publikasjoner.nve.no/rapport/2015/rapport2015_02a.pdf (visited on 04/21/2022).

[135] Preem. *Drivstoffpriser*. URL: https://www.preem.no/norsk/drivstoffpriser/ (visited on 05/09/2022).

[136] Regjeringen. *Avgift på utslipp av klimagasser og veibruksavgift*. URL: https://www.regjeringen.no/no/aktuelt/avgift-pa-utslipp-av-klimagasser-og-veibruksavgift/id2884952/ (visited on 05/12/2022).

[137] SSB. *Konsumprisindeksen*. URL: https://www.ssb.no/priser-og-prisindekser/konsumpriser/statistikk/konsumprisindeksen (visited on 05/03/2022).

A Cost of Transport

The transport costs depends on the distance to the delivery point and the hydrogen demand. Figure 51 summarises the transport costs with compressed hydrogen trucks. Note that the values is given on a levelisd cost of hydrogen basis. The levelised cost of transporting hydrogen (LCOTH) is given for distances between 1 to 500 km and for demands below 5 tonnes per day. Also note that the LCOTH includes compression and storage, in addition to the transport costs itself. This makes the price higher than if transport costs are found alone. However, the figure can be used to illustrate how the LCOTH changes with distance and hydrogen demand.

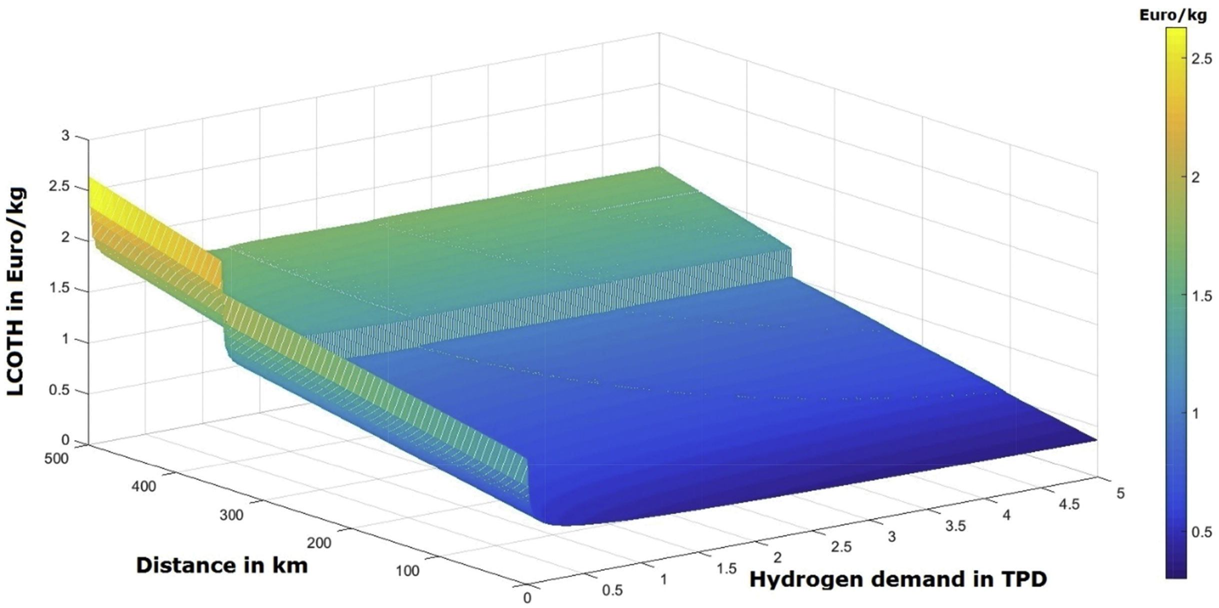

Figure 51: Total levelised cost of transporting hydrogen at low hydrogen demand. [85]

From the figure it can be seen that the LCOTH is changing continuously. It is increasing with distance, and decreasing with increased demand. This illustrates the importance of production in relatively close distance to costumers and economies of scale to further decrease these costs. [85]

B Power Demand

The following data is provided by Tensio. The data contains power consumption from two indsutries in Sørli. The consumption is provided for the years 2019 through 2021.

Figure 52 shows the energy consumption of consumer 1 from 2019 trough 2021. The energy consumption is presented per day.

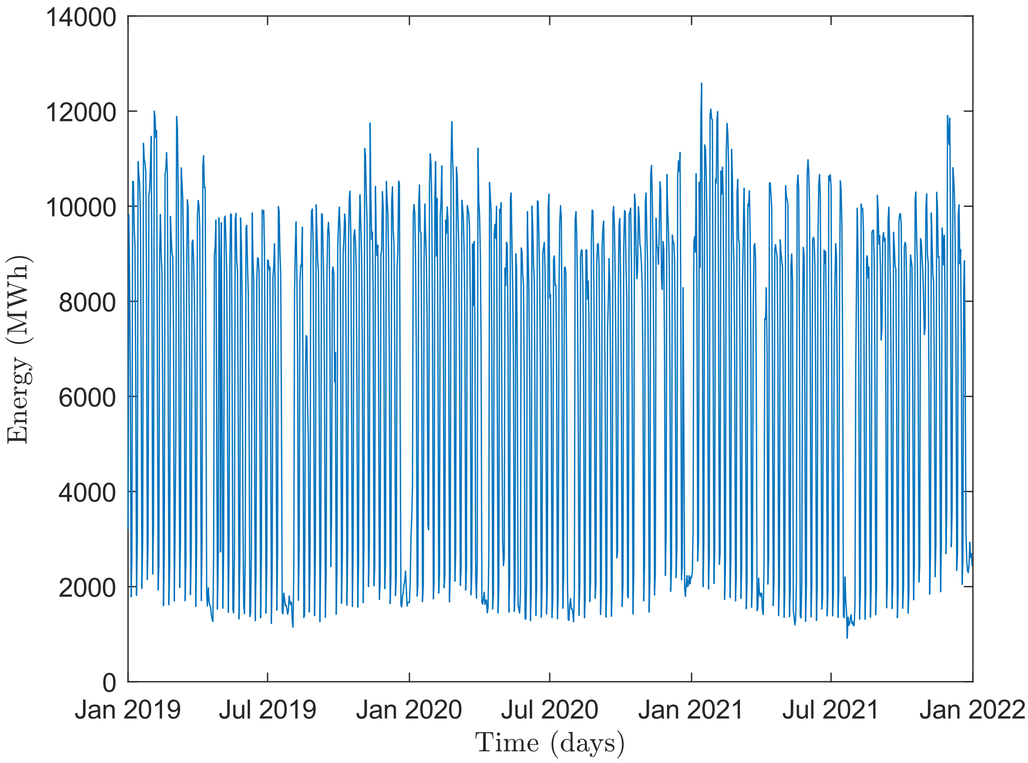

Figure 52: Energy consumption for consumer 1 from 2019 through 2021.

Figure 53 shows the energy consumption of consumer 2 from 2019 trough 2021. The energy consumption is presented per day. Note that consumer two has both a 230 V and 400 V output. These are combined to a total energy consumption for consumer 2

Figure 54 shows the combined energy consumption of consumer 1 and 2 from 2019 trough 2021. The energy consumption is presented per day.

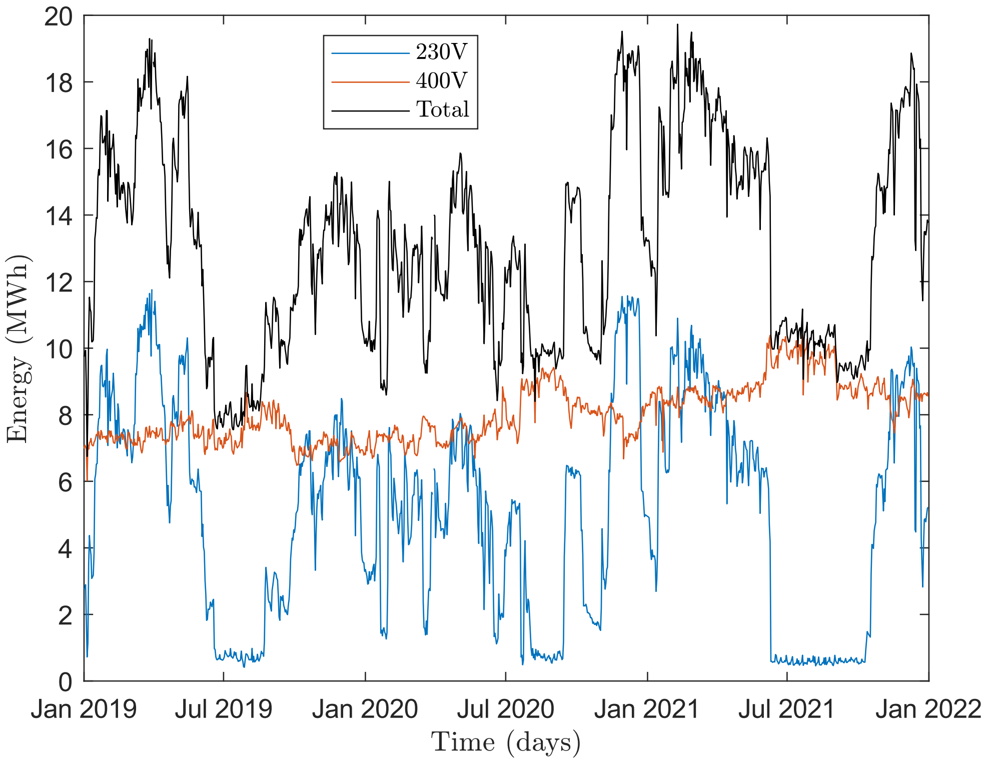

Figure 53: Energy consumption for consumer 2 from 2019 through 2021.

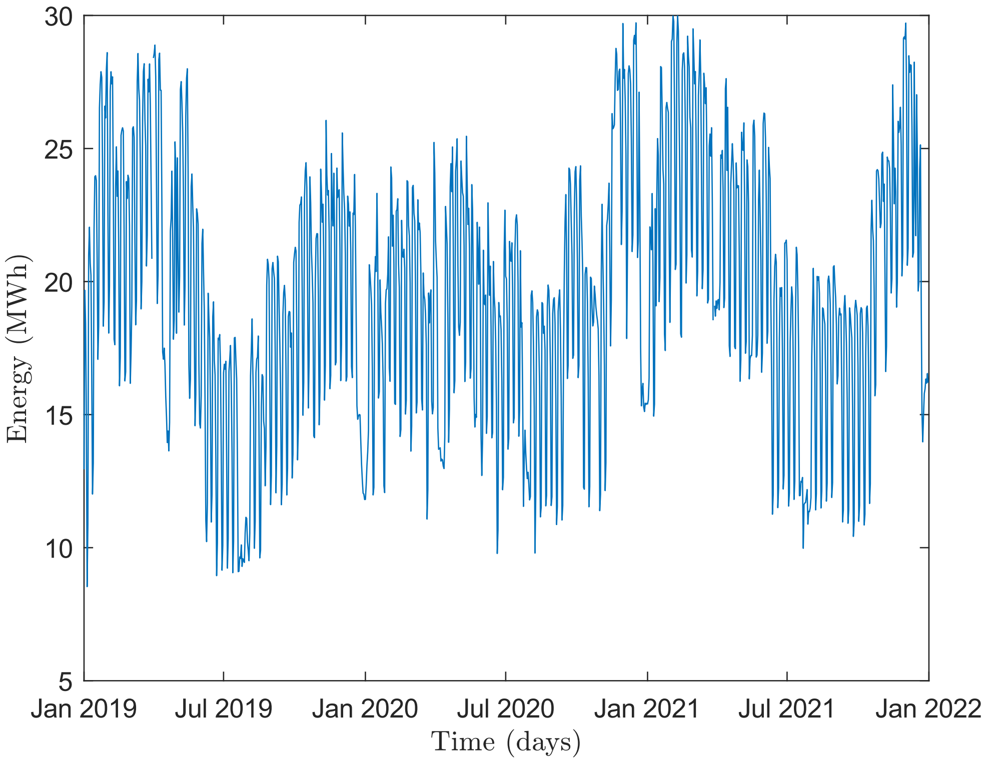

Figure 54: Combined energy consumption for consumer 1 and 2 from 2019 through 2021.

C PEM Electrolysers

Different PEM Electrolysers

Table C.1 presents specifications of different PEM electrolysers from different manufacturers.

Table C.1: Specifications of different PEM electrolysers from different manufacturers. [67]

Manufacture Company	Cap Range [kg$_{H_2}$/h]	Capacity range [Nm$^3_{H_2}$/h]	Pressure [bar]	Energy Consumption [kWh/kg$_{H_2}$]
Siemens	100 - 2000	1000 - 22 400	1 - 35	45 - 65
NEL	3 - 350	30 - 4000	1 - 30	47 - 55
Hydrogenics	0.5 - 450	4 - 5000	1 - 8	55
ITM- Power	10 - 170	110 - 1900	1 - 20	45 - 60
AREVAH2Gen	0.5 - 35	5 - 400	1 - 45	45 - 55
Ginner	3 - 20	30 - 200	1 - 40	N/A

Specifications for the MC250 electrolyser

Table C.2 presents the specifications of the MC250 electrolyser from Nel. Calculations of electrolyser energy consumption and electrolyser efficiency in this thesis is based on this model.

Table C.2: Specification for the MC250 containerised electrolyser from Nel. [116]

	MC250
Net Production Rate	246 Nm^3/h
Net Production Rate	531 kg/24h
Production Capacity Dynamic Range	10 to 100%
Average Power Consumption at Stack	4.5 kWh/Nm^3
Purity (with High Purity Dryer)	99.9995%
O_2-Content in H_2	<1 ppm v
H_2O-Content in H_2	<5 ppm v
Delivery Pressure	30 barg*
Process Container Dimensions - W x D x H	12.2m x 2.5 x 3m
Rectifier/Transformer Container Dimensions - W x D x H	6.1m x 2.5m x 2.6m
Ambient Temperature (Low and High Ambient Temperature Options Available)	-20 to 40^oC
Electrolyte	PEM - Caustic Free

* Pressure measured as gauge pressure.

D Grid Rental Fee for the Electrolyser

Table D.1 presents the grid rental fee for the electrolyser evaluated in this thesis. The prices is presented for one year.

Table D.1: The electrolyser's power and energy consumption, and the grid rental fee per month. [127]

Month	Power [kW]	Energy [kWh]	Power price [NOK]	Energy price [NOK]	Fixed cost [NOK]
Jan	1250	806 452	90 000	34 113	898
Feb	1250	806 452	90 000	34 113	898
Mar	1250	806 452	90 000	34 113	898
Apr	1250	806 452	90 000	34 113	898
May	1250	806 452	13 750	34 113	898
Jun	1250	806 452	13 750	34 113	898
Jul	1250	806 452	13 750	34 113	898
Aug	1250	806 452	13 750	34 113	898
Sep	1250	806 452	13 750	34 113	898
Oct	1250	806 452	13 750	34 113	898
Nov	1250	806 452	90 000	34 113	898
Dec	1250	806 452	90 000	34 113	898
		SUM:	**622 500**	**409 355**	**10 776**

E Correlation between Power and Voltage

Figure 55 and 56 presents data provided by Tensio. The figures shows the correlation between voltage and power at Nordli. It also shows the voltage at Sørli.

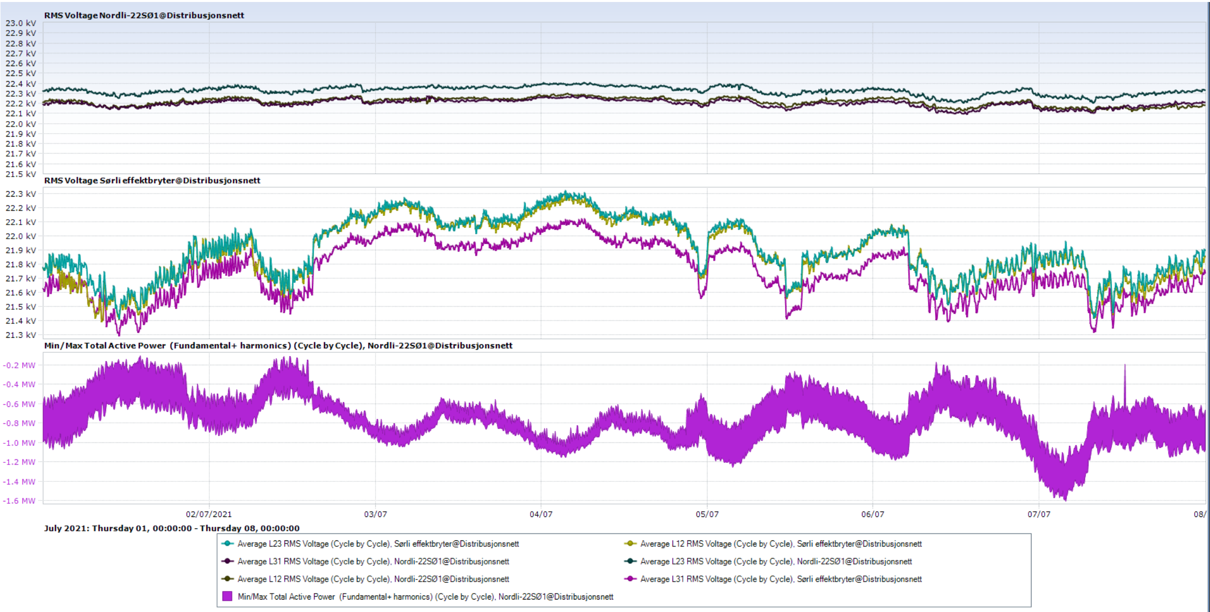

Figure 55: Voltage at Nordli and Sørli, with min/max active power at Nordli in July.

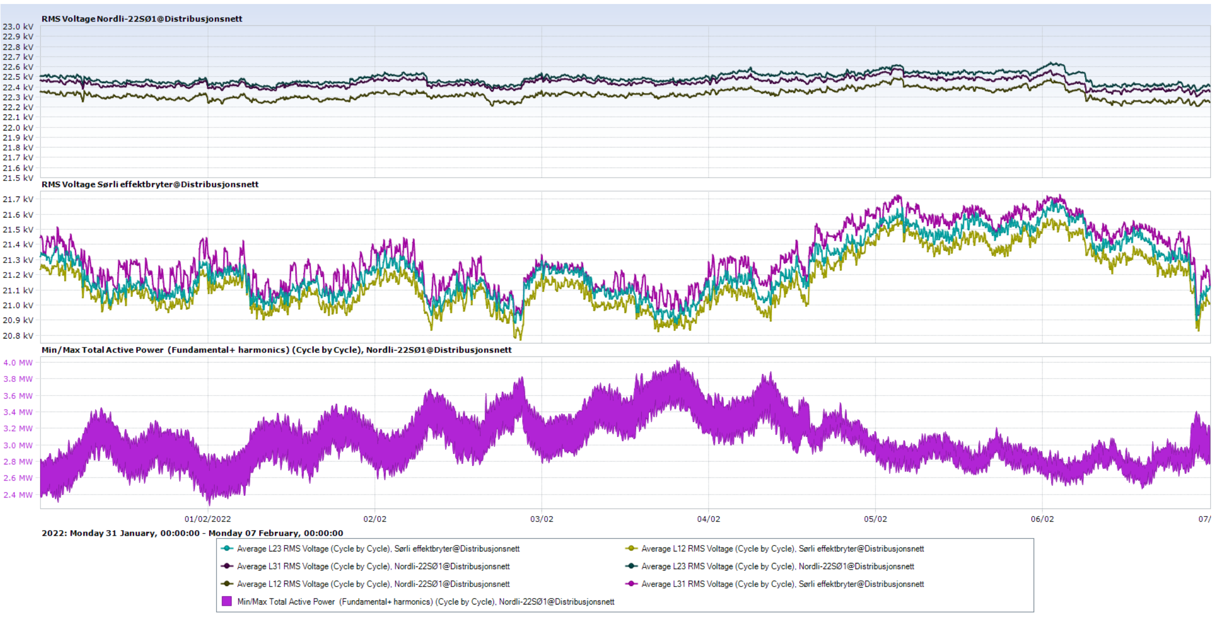

Figure 56: Voltage at Nordli and Sørli, with min/max active power at Nordli in February.

S. Kjørstad, M.E. Lødemel, M.M. Matthews

Integration of a Hydrogen Solution for Solving Power-Related Grid Problems

NTNU
Kunnskap for en bedre verden

NTE