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Hydrogen Production and Storage Optimization based on Technical and Financial Conditions

A study of hydrogen strategies focusing on demand and integration of wind power.

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Abstract

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There has recently been an increased interest in hydrogen, both as a solution for seasonal energy storage but also for implementations in various industries and as fuel for vehicles. The transition to a society less dependent on fossil fuels highlights the need for new solutions where hydrogen is predicted to play a key role. This project aims to investigate technical and economic outcomes of different strategies for production and storage of hydrogen based on hydrogen demand and source of electricity. This is done by simulating the operation of different systems over a year, mapping the storage level, the source of electricity and calculating the levelized cost of hydrogen (LCOH). The study examines two main cases. The first case is a system integrated with offshore wind power for production of hydrogen to fuel the operations in the industrial port Gävle Hamn. The second case examines a system for independent refueling stations where two locations with different electricity prices and traffic flows are analyzed. Factors such as demand, electricity prices and component costs are investigated through simulating cases as well as a sensitivity analysis. Future potential sources of incomes are also analyzed and discussed.

The results show that using an alkaline electrolyzer (AEL) achieves the lowest LCOH while PEM electrolyzer is more flexible in its operation which enables the system to utilize more electricity from the offshore wind power. When the cost of wind electricity exceeds the average electricity price on the grid, a higher share of wind electricity relative to electricity from the grid being utilized in the production, results in a higher LCOH . The optimal design of the storage depends on the demand, where using vessels above ground is the most beneficial option for smaller systems and larger systems benefit financially from using a lined rock cavern (LRC). Hence, the optimal design of a system depends on the demand, electricity source and ultimately on the purpose of the system. The results show great potential for future implementation of hydrogen systems integrated with wind power. Considering the increased share of wind electricity in the energy system and the expected growth of the hydrogen market, these are results worth acknowledging in future projects.

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Populärvetenskaplig sammanfattning

I ljuset av Parisavtalet har intresset för förnybar energi ökat markant och allt fler länder sätter upp mål om utfasning av fossila bränslen. Detta innebär bland annat att vi rör oss mot ett energisystem med mer variabel elproduktion vilket i sin tur kan leda till större fluktuationer i elnätet. För att kunna säkerställa frekvensen i elnätet samt en konstant tillgänglighet av elektricitet behöver energilagringsmöjligheter växa fram i takt med en växande andel förnybar elproduktion. Här tros vätgas kunna spela en nyckelroll i framtiden.

Intresset för vätgas har under det senaste året ökat explosionsartat. Det ökade intresset kommer inte enbart av vätgasens förmåga att lagra energi över långa tidsperioder utan också dess stora potential inom andra sektorer såsom industri och fordonsbränsle. Europeiska kommissionen har beslutat att investera 430 miljarder euro för att stimulera utbyggnaden av vätgasinfrastruktur i Europa. I Sverige lanserades nyligen en nationell vätgasstrategi som ett verktyg att uppnå mål om ett fossilfritt Sverige 2030. Ett företag som vill haka på trenden är Gävle Hamn AB som undersöker möjligheterna för att ställa om sin verksamhet till vätgasdrift. För att undersöka möjligheterna till att integrera vätgasproduktion med förnybar energi har Gävle Hamn varit i kontakt med vindkrafts-företaget Svea Vind Offshore. Företaget har projekterat havsbaserade vindkraftsparker utanför Gävles kust som skulle kunna kopplas ihop med ett framtida system för grön vätgasframställning i hamnen.

Utformandet och driften av storskalig vätgasproduktion samt lagring är relativt outforskat både i Sverige och i övriga världen. I takt med vätgasens snabba frammarsch ökar dock behovet av att undersöka detta. Denna studie ämnar undersöka hur storskalig vätgasframställning och lagring kan optimeras utifrån tekniska och ekonomiska förutsättningar. Detta görs genom två fallstudier; ett vätgassystem i Gävle Hamn i anslutning till havsbaserad vindkraft och ett vätgassystem för fristående vätgastank-stationer med eltillförsel från elnätet.

Studien tog avstamp i en omfattande litteraturstudie samt kontakt med experter inom främst vätgasindustrin. Utifrån den teoretiska grunden undersöktes vilka komponenter som krävs i ett vätgassystem, vilka vätgasproduktionstekniker (elektrolysörer) som var lämpade för de olika fallen, vilka lagringsmöjligheter som var värda att undersöka samt en framtidsanalys för att uppskatta efterfrågan på vätgas för dimensionering av systemen. De elektrolystekniker som valdes till studien för jämförelse var alkalisk- (AEL) samt PEM elektrolysör. Alkalisk elektrolysör är i dagsläget billigare än PEM, medan PEM är mer flexibel i sin styrning vilket möjliggör en anpassning av produktionsnivån efter rådande elpriser och tillgång på vindkraft. I Gävle Hamn undersöktes tre lagringsalternativ och av dessa var två metoder underjordslagring; dels återanvändning av existerande lager i hamnen som idag används för att lagra petroleumprodukter och dels konstruktion av ett nytt bergrum, en så kallad Lined Rock Cavern (LRC). Den tredje lagringsmöjligheten var att använda stålbehållare ovan jord. Dessa tre alternativ jämfördes utifrån lagringskapacitet och kostnadsaspekter. För vätgasproduktionen i anslutning till vätgasmackarna undersöktes endast ett lagringsalternativ, vätgastankar ovan jord.

Systemen designades på olika sätt för att undersöka hur de bör utformas, dimensioneras och styras beroende på olika faktorer. En avgörande parameter var eltillförseln till elektrolysörerna. För Gävle Hamn, som ligger i anslutning till framtida havsbaserade vindkraftsparker, simulerades två scenarier; eltillförsel från enbart vindkraft samt en kombination av vindkraftsel och el från elnätet. Scenarierna för vätgasstationerna nyttjade enbart el från elnätet. Olika system med varierande inparametrar såsom produktionsteknik, elpriser och vindförhållanden, lager samt storlek på efterfrågan simulerades i MATLAB. Detta för att undersöka trender i produktion samt lagringsnivåerna i vätgaslagren. För samtliga simulerade system beräknades den så kallade Levelized Cost of Hydrogen (LCOH) som är den totala produktionskostnaden för vätgasen.

Resultaten visar att AEL innebär lägre produktionskostnader för vätgas medan PEM möjliggör flexibel styrning av vätgassystemen vilket bland annat medför att en högre andel vindkraftsel kan användas. Baserat på prognoser som indikerar en kraftig prisnedgång för PEM-teknik samt fallande vindelspriser så kan PEM anses vara en intressant teknik för framtida vätgasframställning. Vätgasproduktionen bör då styras enligt en rörlig prisgräns för att fånga fördelaktiga elpriser och optimera användningen av vindkraftsel. Systemet bör också ta hänsyn till andelen vätgas som finns tillgängligt i lagret för att säkra en konstant tillgång som alltid möter efterfrågan. Studien visar att stålbehållare för vätgaslagring ovan jord är mer ekonomiskt fördelaktigt för mindre system och LRC är mer fördelaktigt för stora system. Val av lagringsmetod beror således på hur stor efterfrågan på vätgas beräknas vara under systemets livstid. Att återanvända ett befintligt bergrum i Gävle Hamn visade sig vara dyrare än de andra två alternativen för samtliga simulerade fall. Dock behövs en mer grundlig analys av berggrundens egenskaper för att säkerställa detta resultat.

Något som är gemensamt för samtliga fall i Gävle Hamn och vätgastankstationerna är att LCOH minskar för större system. En högre andel vindkraftsel till vätgasproduktion resulterar i högre kostnader på vätgas, vilket beror på relativt höga vindelspriser. Lägst LCOH erhölls med vätgassystem för de frikopplade vätgastankstationerna som enbart använde el från nätet, där möjlighet att producera med lägre elpriser resulterade i lägre LCOH. Detta indikerar att ett system med en stor andel integrerad vindkraft får svårt att konkurrera med ett system med eltillförsel enbart från elnätet ur ett ekonomiskt perspektiv. Däremot kan framtida fallande vindelspriser leda till att flexibel vätgasproduktion i anslutning till havsbaserad vindkraft kan bli mer ekonomiskt konkurrenskraftigt jämfört med konstant produktion med eltillförsel från elnätet med alkaliska elektrolysörer. Det kan även vara fördelaktigt för systemet med vindkraftsel att producera vätgas istället för att sälja elen till nätet vid låga elpriser.

Projektet är ämnat som ett ramverk för framtida studier inom storskaliga vätgassystem. Kostnader för lager och elektrolysörer med mera kommer med stor sannolikhet skilja sig vid en framtida implementation av ett system, vilket också kan komma påverka vilka tekniker som är mest fördelaktiga. Denna studie visar dock på intressanta resultat beträffande den framtida potentialen för vätgassystem i anslutning till havsbaserad vindkraft. Resultaten är värda att ta i beaktande med tanke på vätgasens förmodade expansion samt att vindkraft utgör en allt större del i energisystemet.

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This project ends the chapter for us as students at the Master's Program in Sociotechnical Systems Engineering at Uppsala University. So lastly, we would like to thank all our friends we made during our time in Uppsala. You have truly enlightened these years, been an incredible support during the studies and made life outside school so much fun.

Thank you!

Hanna Langels & Oskar Syrjä
February 2021

Contribution statement

The project was carried out through continuous collaboration between two Master of Science in Engineering students, Hanna Langels and Oskar Syrjä. They have collaborated on all areas covered in this project, but the workload within each area was distributed according to the author's competencies. Oskar, whose master was profiled more towards IT, carried out the main parts in MATLAB coding and preprocessing the data. Hanna, whose master was more profiled towards project management and business, was mainly responsible for economic calculations and contact with people in the hydrogen industry. The thesis was jointly written and processed and the evaluation, as well as interpretation of the results, was conducted in common. All parts of the thesis are fully backed by both authors.

Abbreviations and Concepts

HES	Hydrogen Energy System
PEM	Polymer electrolyte membrane
AEL	Alkaline electrolyzer
SOEC	Solid oxide electrolyzer
PV	Photovoltaics
CAPEX	Capital Expenditures
OPEX	Operational Expenditures
EV	Electric vehicle
TSO	Transmission System Operator
SVK	Svenska kraftnät
DC	Direct current
LCOE	Levelized Cost of Energy
LCOH	Levelized Cost of Hydrogen
VAT	Value-added tax

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1. Introduction

There is currently a large international expansion of renewable energy sources in the light of the Paris Agreement. As part of a transition to an energy system less reliant on fossil fuels, the European Commission has set up 2030 Climate and Energy Frameworks that include reducing greenhouse gas emissions by 40 percent and introducing a share of at least 32 percent renewable energy sources by 2030 (European Commission, 2020a). However, a higher dependency on intermittent power production comes at a cost, and that is the cost of variability. We are transitioning from a society with variable electricity demand and controllable supply, to variable demand and variable supply. The shift towards an energy system less reliant on fossil fuels requires solutions for storing excess renewable energy to be used on-demand. In this regard, hydrogen is believed to play a key role in the future energy system.

The reason why hydrogen is such a promising candidate for this purpose is because of its ability to store large quantities of energy for extended periods. This feature makes it a promising technology to overcome the difficulties of storing renewable energy and provide stability to the electricity grid. Hydrogen storage enables the capturing of energy that otherwise would be curtailed[1] during times of excess energy production to be used later at times of high demand.

Recently there has been a major uptake of hydrogen. This is not only due to hydrogen's ability to work as a large-scale seasonal storage medium, but also because it can provide multiple other services. These services include various applications in the industry, heat, and transport sectors. Studies show that large-scale hydrogen production can even potentially work as a balancing actor on the electricity market. Even though the technology is promising, the large-scale implementation of a hydrogen market is still in its infancy and incorporating hydrogen into the energy system, and making it viable, includes huge investment costs. To stimulate the hydrogen economy, the European Commission has decided to invest 430 billion euro (EUR) in hydrogen infrastructure by 2030 (European Commission, 2020b). This implies that hydrogen is on the rise, and many implementations of hydrogen in various sectors can be expected in the forthcoming years.

The Swedish government is currently developing a hydrogen strategy to identify the challenges that require national coordination to enable different value chains and sectors to accelerate towards making Sweden one of the world's first fossil-free welfare states. (Vätgas Sverige, 2021) Large industrial companies such as Vattenfall, LKAB, and Siemens Energy AB have already begun to incorporate hydrogen in their industries to decarbonize their operations (HYBRIT Development AB, 2020; Vätgas Sverige, 2019). Gävle Hamn AB, the authority of the largest container port on the Swedish East Coast, is another company with plans on a hydrogen transition (Astner, 2020). In the same area, outside the coast of Gävle, the wind power company Svea Vind Offshore has projected plans on implementing offshore wind farms (Svea Vind Offshore, 2020). Svea Vind Offshore also have an interest in looking into the possibilities of hydrogen production.

[1] Curtailment, in terms of energy, is the deliberate reduction in output below what could have been produced (Level10Energy, 2019).

Considering the planned offshore wind farms, it would be interesting to investigate a hydrogen production system in Gävle Hamn directly connected to the wind power plants.

Large-scale hydrogen production systems in connection to renewable energies have yet to be implemented in Sweden and remains relatively unexplored worldwide. Due to the indications that hydrogen is on the rise, but the development of hydrogen infrastructure still being in its infancy, investigations regarding implementations of large-scale hydrogen energy systems are highly interesting and essential.

1.1 Research Aim

This study aims to investigate how large-scale hydrogen production and storage, with a focus on the latter, can be designed and regulated for optimal utility from a financial and technical perspective. To achieve this, different hydrogen systems are reviewed for two separate business cases. The first case investigated is a hydrogen production facility connected to offshore wind farms in Gävle Hamn. The second case is two independent hydrogen refueling stations using electricity from the grid for hydrogen production. The purpose is to find the optimal storage option for these two cases which depend on different production factors and demand scenarios as well as technical and financial conditions. To achieve the purpose of the study, the following research questions are reviewed:

- What hydrogen production technology is better suited depending on the source of electricity and demand of hydrogen?
- How should hydrogen storage be dimensioned and operated depending on the production and demand of hydrogen?
- What are the final costs of hydrogen depending on electricity source, hydrogen production technology, storage option, and demand scenario?

1.2 Delimitations

The main scope of the study is to capture a holistic perspective of the investigated systems rather than focusing on specific details. Due to the many different components included in a hydrogen energy system (HES), each has to be accounted for to make realistic simulations of a potential system, but none is given room for a deeper analysis. The thesis investigates systems where the hydrogen is produced at the location of the end-use. Different techniques of hydrogen transportation are presented but not reviewed as an alternative for the study. Losses in the different system stages, e.g. compression, are not included in the study since they were associated with uncertainties and strictly connected to the specific selection of components. Simplifications were made regarding the cost of wind electricity since the costs depend on a large variety of factors not accounted for in the thesis. Regarding the electricity price on the grid, the simulations were based on the market price from the Nord Pool day-ahead market. The additional costs charged by the electricity trading companies and the electricity grid owners were not included due to uncertainties connected to the lack of public data. These delimitations are not assumed to affect the end result to a large extent and since the impact is similar for all simulated cases, the main trends are not affected by this. The fact that an actual system like the one investigated does not yet exist, means that there is no current frame of reference which introduces a level of uncertainty to the project.

1.3 Thesis Outline

The thesis is structured in the following way. Chapter 2 provides the theoretical background that serves as a basis for the project. Chapter 3 presents the studied cases – the HES in Gävle Hamn and the independent refueling stations in Sundsvall and Södertälje. In chapter 4, the data used for this project and information regarding how it was gathered is presented. Chapter 5 explains the methodology of the project, including preprocessing of data, the simulations in MATLAB, and the sensitivity analysis. In chapter 6 the results from the simulations are presented as well as the Levelized Cost of Hydrogen (LCOH) for the different cases. Chapter 7 provides an interpretation and discussion of the results as well as thoughts of future research. Lastly, the conclusions from this project are summarized in chapter 8.

2. Background and Literature Review

This chapter provides a theoretical background and serves as a basis for the concepts that were used in this project. The outline of the chapter is first an introduction to the concept of hydrogen and the recent uptake on the energy source, followed by different hydrogen applications in various sectors. Further, different technologies for hydrogen production, compression, storage, and utilization will be explained. Offshore wind energy, the Swedish electricity grid, taxes, and the electricity market are all subjects relevant for this study and will therefore also be presented in this chapter. Lastly, the economic modeling tool used to estimate the Levelized Cost of Hydrogen for the financial analysis will be explained. To enable a financial analysis of hydrogen, the related costs of the different components in a HES will be presented in each section.

2.1 Hydrogen on the Rise

Hydrogen is the most abundant element in the universe. The atomic structure of hydrogen is one electron and a single proton which makes it the lightest and simplest of all chemical elements. In gaseous form, hydrogen has a very low density of 0.0899 kg per m^3 (Nordling & Österman, 2006), which is equivalent to one kg of hydrogen gas occupying 11 m^3 in room temperature and atmospheric pressure (Schlapbach & Züttel, 2001). Under high pressure, hydrogen has the highest mass density of any fuel known today which makes it an efficient medium for energy storage and distribution (European Commission, 2016).

Today, approximately 90 percent of all hydrogen produced is used in the chemical industry. About 55 percent is used for ammonia synthesis mainly for the fertilizer market, 25 percent is used in refineries, and 10 percent in methanol production. The remaining 10 percent account for other applications globally (Hydrogen Europe, 2020). Some of these applications include hydrogen as fuel in the transport sector, electricity generation and to act as a buffer to increase energy system resilience (Hydrogen Council, 2020a).

A major issue with hydrogen production today is its carbon footprint where approximately 96 percent of all hydrogen today is produced using fossil fuels (Nguyen et al., 2019). As a consequence, the hydrogen industry is responsible for approximately 830 million tonnes of carbon dioxide emissions every year (IEA, 2019a)._Hydrogen can however also be produced through water electrolysis using electricity, a process called Power-to-Gas (P2G). If the electricity in this process is generated by renewable energy sources the product is referred to as clean or green hydrogen. In recent years there has been an increase in the number of countries with policies that directly support investments in clean hydrogen technologies and the sectors they target (IEA, 2019a). The main factor behind this uptake is to decarbonize the energy system, where the European Clean Hydrogen Alliance sees renewable or low carbon hydrogen as a key enabler for Europe's clean energy transition (European Commission 2020b).

In the summer of 2020, the European Commission (2020c) announced the project *Hydrogen Strategy* which involves different phases of development to achieve a clean hydrogen economy. By 2050 renewable hydrogen technologies are predicted to have reached full maturity and able to be deployed on a large-scale, which enables the technology to become advantageous in sectors still left to decarbonize. The International Energy Agency, IEA, (2019a) has, in turn, identified four near-term opportunities to boost the expansion of hydrogen:

- Make industrial ports the nerve centers for scaling up the use of clean hydrogen
- Build on existing infrastructure, such as millions of kilometers of natural gas pipelines
- Expand hydrogen in transport through fleets, freight, and corridors
- Launch the hydrogen trade's first international shipping routes

The ongoing uptake and large investments in hydrogen infrastructure in Europe is an opportunity for the hydrogen market to grow and for renewable energy sources to grow with it. The Hydrogen Council (2017a) predicts that the global hydrogen demand could rise tenfold by 2050.

2.2 Hydrogen Applications

The versatility of hydrogen makes it applicable in many different sectors. This section will first focus on applications in the industry sector, followed by introducing and explaining the concept of Power-to-Power (P2P). Lastly, hydrogen implementation in the transport sector will be presented. Hydrogen is used in multiple other sectors but due to the scope of this project, these will not be investigated.

2.2.1 Industry

Hydrogen has been used in various industries for decades and the demand is forecasted to increase driven by the shift from fossil fuels to renewable energy sources (Global Market Insights Inc., 2020). Examples of industrial applications of hydrogen are petroleum refining, electronics industry, fuel production, glass purification, fertilizer production, heat-treating metals, production of fatty acids in vegetable oil, and the steel industry (Hydrogen Tools, n.d.). Integration of hydrogen in the steel industry is currently taking place in the pilot-project HYBRIT in Luleå, northern Sweden. The HYBRIT project started in 2016 and is a collaboration between the Swedish steel and energy and mining companies Vattenfall, SSAB, and LKAB. HYBRIT stands for Hydrogen breakthrough ironmaking technology and aims to replace coal in the steelmaking process. This by introducing hydrogen in the reduction process of separating oxygen from the iron ore with the incentives to reduce CO_2 emissions and decarbonize the industry (Åhman et al., 2018). A pilot-plant for hydrogen production using electrolysis from renewable energy sources was launched on the 31st of August 2020. The next phase starting in 2021 is the planning, testing, and construction of large-scale hydrogen storage which will ensure the access of hydrogen for the industrial process during all hours of the year (HYBRIT Development AB, 2020). The cost of the storage is estimated to be around 200 million Swedish crowns (SEK) of which 50 million SEK will be subsidized by the Swedish Energy Agency (Vattenfall, 2019).

2.2.2 Power-to-Power

The concept of Power-to-Power (P2P) in the subject of hydrogen refers to the process of using electricity to produce hydrogen, storing it, and later converting the hydrogen back to power, e.g. in form of electricity. This could for instance be implemented when producing electricity during a high supply and low demand period, storing the energy and using it later at times of low electricity supply and high demand. By reducing the difference between demand peaks through load-shifting it can help provide stability to the electricity grid. The number of services and flexibility a hydrogen system can provide to the electricity grid makes it an interesting application. However, the conversion of energy always results in energy losses, where P2P suffers from low efficiency of 30 to 35 percent (Steen, 2015).

In the report *Modelling and evaluation of PEM hydrogen technologies for frequency ancillary services in future multi-energy sustainable power systems,* Alshehri et al. (2019) examines the possibilities of PEM electrolyzers and fuel cells[2] to part-take in the European electricity market for ancillary services. The paper concluded that it can be a feasible option for systems with electrolyzers and fuel cells to operate at markets of frequency regulation and voltage control. The capability of fast change in the power consumption of the electrolyzers as well as the fast power injections of fuel cells are attractive features for the frequency regulation and partaking in these markets could give a supplementary source of revenue for the business models of these systems (Alshehri et al., 2019).

The most common technology used to convert the energy stored in hydrogen back to electricity is through fuel cells. Fuel cells generate electricity by converting the chemical potential energy in molecules to electricity through an electrochemical reaction. In most fuel cells, hydrogen and oxygen are combined to create electricity and water. A fuel cell consists of a cathode, an anode, and an electrolyte membrane. Hydrogen enters the anode side where a catalyst splits the molecules into protons and electrons. The hydrogen protons then pass through the electrolyte membrane while the electrons generate a current by being forced through a circuit. On the cathode side the protons, electrons, and oxygen combine to create water. The components and reactions in a fuel cell are shown in Figure 1.

[2] Fuel cells are electrochemical cells that convert the chemical energy of a fuel and an oxidizing agent into electricity (U.S department of energy, 2015).

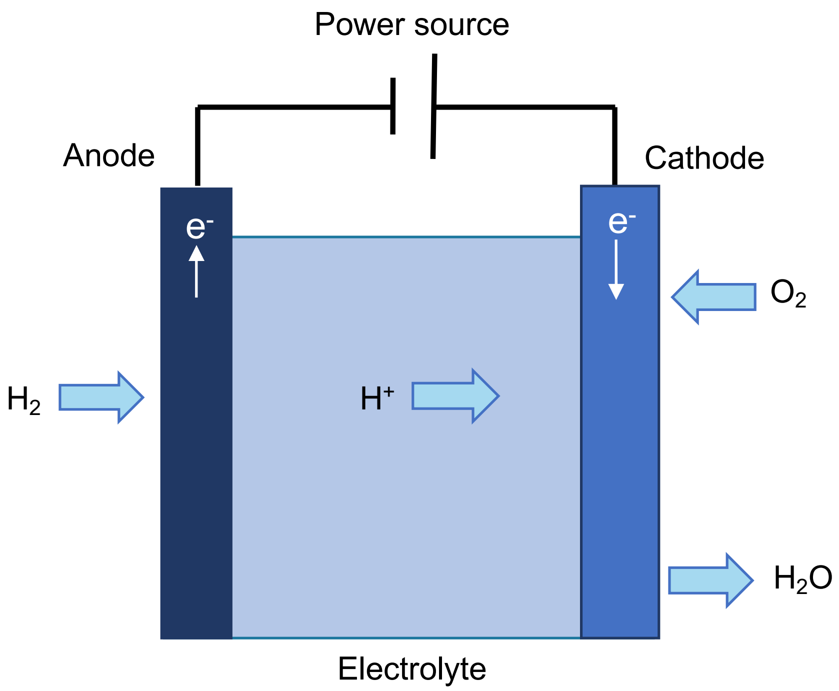

Figure 1. Illustration of fuel cell components and reactions. Inspiration for illustration from "Fuel Cell Technologies Office Multi-Year Research, Development, and Demonstration Plan2" by U.S department of energy (2016).

Since the only byproducts are electricity, heat, and water, the electricity can be carbon-free if green hydrogen is used. According to the Fuel Cell and Hydrogen Energy Association (FCHEA), generating electricity through an electrochemical reaction instead of combustion enables higher efficiency than the traditional methods for electricity generation (FCHEA, 2020).

2.2.3 Transport Sector

Today, 27 percent of all greenhouse emissions in Europe are generated by the transport sector, including emissions from aviation and maritime traffic (European Environmental Agency, 2017). Road transport accounts for approximately 21 percent of these emissions, (European Commission, 2020d) of which the European Commission has proposed a reduction by 15 percent until 2025 (European Parliament, 2019).

A rapid shift in the private car industry towards zero emissions has already begun in the form of electric vehicles (EV). The market and infrastructure around EVs today is already well established with approximately 560 000 registered all-electric cars and plug-in hybrids in Europe, and over 190 000 fueling stations (Autovista Group, 2020). However, due to factors such as limited driving range, relatively slow-charging, and the usage of rare metals like lithium and cobalt for batteries, it is unlikely that electric vehicles will be able to replace fossil-fueled vehicles alone. Hydrogen is believed to be a suitable candidate to complement EVs and together make up a hybrid infrastructure that optimizes the use of renewable energy in the transport sector (Robinius et al., 2018). Steve Szymanski, Director of Business Development at Nel Hydrogen, stated in an interview that selling hydrogen as transportation fuel might be the highest value to end-use for hydrogen (Rice, 2020).

Hydrogen-fueled vehicles in contrast to EVs generally have a longer driving range and more rapid refueling. The lifetime of a battery in a vehicle and fuel cell is approximately the same, 100 000 to 300 000 km (Cox et al., 2020). However, the rapidly growing interest in EVs as the green alternative to fossil-fueled vehicles in the EU has prevented the uptake of hydrogen fuel cell vehicles. The already well-established infrastructure and market around EVs as well as legislations promoting EVs make it harder for hydrogen vehicles to enter the market, foremost in the automotive industry. In order for the hydrogen fuel market to grow, policies to introduce sufficient public refueling infrastructure is necessary (European Commission, 2020c).

Regarding the heavy-duty transport industry, manufacturers believe that hydrogen fuel cells have great potential. This is due to hydrogen-fueled heavy-duty vehicles being a more economically viable option than EVs in the aspects of refueling time as well as the size and weight of a battery versus a hydrogen tank (Howden Group, 2020). According to *The Energy Transition Outlook 2019* report it is anticipated that 5-13 percent of all heavy-duty vehicles will be powered by hydrogen fuel cells by 2050 (DNV GL, 2019). In the summer of 2020, the world's first mass-produced fuel-cell-powered heavy-duty truck, manufactured by Hyundai, was shipped to Switzerland. They expect to roll out 1600 trucks by 2025 (Hyundai, 2020).

Hydrogen within the material handling industry is another usage area on the rise. In the pre-study *Bränslecellsdrift av tunga truckar - Potential inom processindustrin* by Angelika Treiber (2016) a survey was made of forklifts and industrial vehicles with the future possibility of using hydrogen as fuel. The large-scale material handling vehicles such as forklifts and wheel loaders are today mainly fueled by fossil fuels. The study shows that by a transition to hydrogen using fuel cell technology, energy consumption could be reduced by 30 percent due to the higher efficiency of fuel cells compared to diesel engines, and carbon dioxide emissions could be reduced by up to 80 percent. Another advantage is that hydrogen-fueled vehicles typically need less maintenance than their diesel-fueled counterparts. However, to this day only fuel cell forklifts with a maximum lift capacity of 4.5 tons have been commercialized. This can be compared with commercialized battery counterparts that can reach a lift capacity of 12 tons and conventional diesel-fueled forklifts can reach a lift capacity of up to 100 tons. In theory, fuel cell forklifts can reach the same capacity, but the lack of demand has prevented these machineries from entering the market.

As long as the driveline of the vehicle is electrical, a switch from battery to fuel cell is relatively simple. In 2019, the manufacturers Raniero and FTMH revealed that they had developed an electric heavy forklift with a lift capacity of 25 tons (Raniero, 2019). As a part of the *H2ports* project funded by the EU, a hydrogen-fueled reach stacker, as well as a hydrogen terminal tractor, are under development to take part in the container handling operations within the port of Valencia (Fuel Cells Bulletin, 2019).

Except for the above-mentioned vehicle applications for hydrogen, the technology has also started to make its way into rail transport and aviation. Hydrogen-powered trains are already implemented in Germany and many other countries, e.g. Spain and Sweden, are also looking into the possibilities of applying hydrogen in the railway system (FuelCellsWorks, 2020; Vätgas Sverige, 2020). Regarding aviation, the aircraft manufacturer Airbus has three concepts under development to enable commercial aircraft with hydrogen as a primary fuel, with plans on launching the first planes by 2035 at the latest (Airbus S.A.S, 2020).

2.3 Hydrogen Production

This section will start by explaining the concept of hydrogen production through water electrolysis. Further, the different technologies available today will be introduced followed by a comparison between the two most mature technologies, Alkaline and PEM water electrolysis.

2.3.1 Hydrogen Production through Water Electrolysis

As mentioned previously, hydrogen can be produced through the conversion of electrical energy through water electrolysis. Hydrogen production through water electrolysis has an advantage compared to hydrogen produced by fossil fuels because it can utilize electricity from renewable energy sources. In the electrolysis process, electricity is used to decompose water molecules into hydrogen and oxygen. The reaction is shown in Equation 1.

$$2H_2O = 2H_2 + O_2 \tag{1}$$

The reaction takes place in an electrolyzer that consists of one or more cells. The cells are made up of two electronic conductors called electrodes, submerged by an ionic conductor, the electrolyte. A compilation of cells assembled is called electrolysis stack. The electrolyzer can in turn consist of multiple stacks, where the size of the system determines how much hydrogen can be produced. The electrolyzer stacks are surrounded by multiple components to control the flow rate of water and gas evacuation as well as to regulate the pressure, operating temperature, purity, and power supply (Olivier et al., 2016).

For the electrolysis process, it is necessary to use water with adequate purity, and that this purity remains during the operation. When using tap water, it needs to go through several purification steps and be deionized before it can be used in the electrolysis. The electrolysis process results in excess heat produced by internal dissipation during operation at a non-zero current density that needs to be removed. Heat-dissipation is usually the factor that determines the maximum operation current density of the electrolysis system (Bessarabov et al., 2018).

Currently, three major water electrolysis techniques are commercially available on the market or under development – alkaline electrolysis (AEL), proton exchange membrane electrolysis (PEM), and solid oxide electrolysis (SOEC). The latter, SOEC, works in high temperatures of approximately 500-850 °C and has very high efficiency. Recently, there has been an uptake in the interest of the SOEC technology. This is partly because of its high efficiency, approximately 30 percent more efficient at the same hydrogen production rate as PEM electrolyzers (Tang et al., 2018), and the fact that SOEC does not require as much electricity to produce the same amount of hydrogen as AEL or PEM (Nguyen, 2019). However, this technology is still under development and due to the fact that it has not yet been commercialized, it will not be accounted for in this study.

2.3.2 Alkaline Water Electrolysis

Alkaline electrolyzers (AEL) have been in commercial use since the middle of the 20th century and have played a huge role in the chemical industry. It is considered to be the most mature electrolysis technique today and most commonly used in industries. A simplified illustration of an alkaline electrolyzer, its components, and the reactions that take place can be seen in Figure 2.

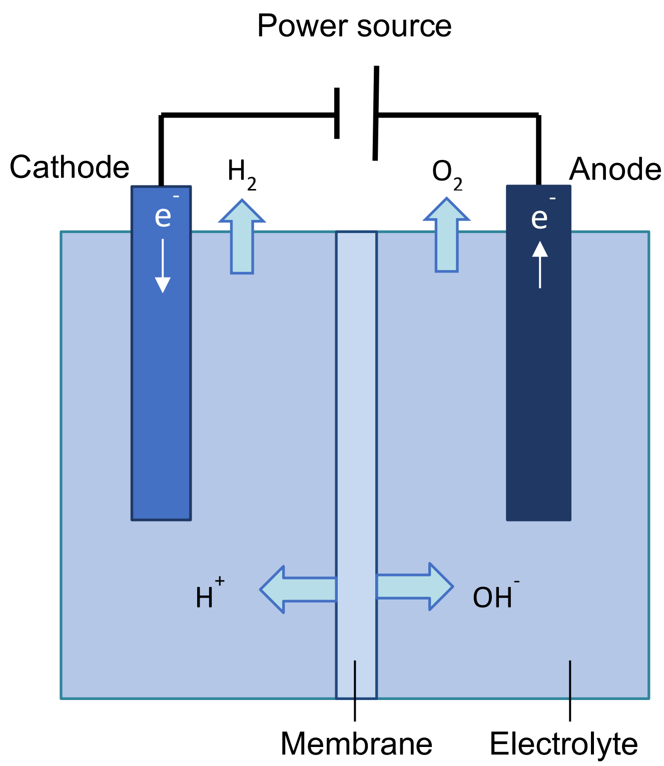

Figure 2. Schematic of alkaline electrolyzer components and reactions. Inspiration to illustration from Guo et al. (2019)

In AEL, two electrodes are lowered into an alkaline aqueous electrolytic fluid containing either a 25-30 percent potassium hydroxide (KOH) solution or a sodium oxide (NaOH) solution. The electrodes are most commonly made by high-conductive steel plates with nickel treatment that is separated by a NiO diaphragm with low conductivity and low permeability. The diaphragm is made of an insulating material that allows hydroxide ions to pass through. When direct current is applied, two water molecules dissociate into hydrogen and hydroxide ions on the cathode side of the reaction which is shown in Equation 2 (Keçebaş et al., 2019).

$$4H_2O + 4e^- \rightarrow 2H_2^+ + 4OH^- \tag{2}$$

The hydroxide then moves through the membrane to the anode side, where oxygen and water are formed, see Equation 3.

$$4OH^- \rightarrow O_2 + 2H_2O + 4e^- \tag{3}$$

The total reaction of the single-cell chamber electrolysis reaction can be summarized as shown in Equation 4.

$$4H_2O \rightarrow 4H_2^+ + 2O_2 \tag{4}$$

During operation, the direct current (DC) density usually lies between 2000-7000 A/m^2. The working temperature is generally maintained at 80°C to 90°C and the working pressure below 32 bars. AEL cells cannot operate at low current densities, which limits the flexibility during operation required for integration with intermittent renewable energy sources (Guo et al., 2019). There is however, according to Carlos Bernuy-López (2021) who is R&D Senior Engineer within Fuel Cells at Sandvik Materials Technology, ongoing research in enabling more flexibility for AEL when operating under higher pressure. More filed data is needed to confirm this, and for that reason the documented information regarding AELs inability for flexible regulation will be the premise for this study.

The purity of hydrogen is a critical characteristic in several applications, for example in fuel-cells. For fuel-cell applications, a purity of 99.998 percent is required. The hydrogen produced through alkaline electrolysis has a purity rate of 99.8-99.999 percent depending on the electrolyzer. For electrolyzers with a purity rate below 99.998, the hydrogen produced needs to go through a certain purification process to remove impurities such as carbon monoxide, residual traces of electrolyte, oxygen, and water by using a scrubber, deoxidizer, and dryer (Nel Hydrogen 2020).

2.3.3 Polymer Electrolyte Membrane Electrolysis

The structure of a polymer electrolyte membrane (PEM) electrolyzer is similar to AEL. The difference is that PEM uses a thin-film solid proton exchange polymer electrolyte membrane instead of an aqueous solution as an ionic conductor used in AEL. The most commonly used membrane material is Nafion. The anode and cathode are attached to both sides of the membrane by electroless plating or hot pressing (Guo et al., 2019). A simplified illustration of an alkaline electrolyzer, its components, and the reactions that take place can be seen in Figure 3.

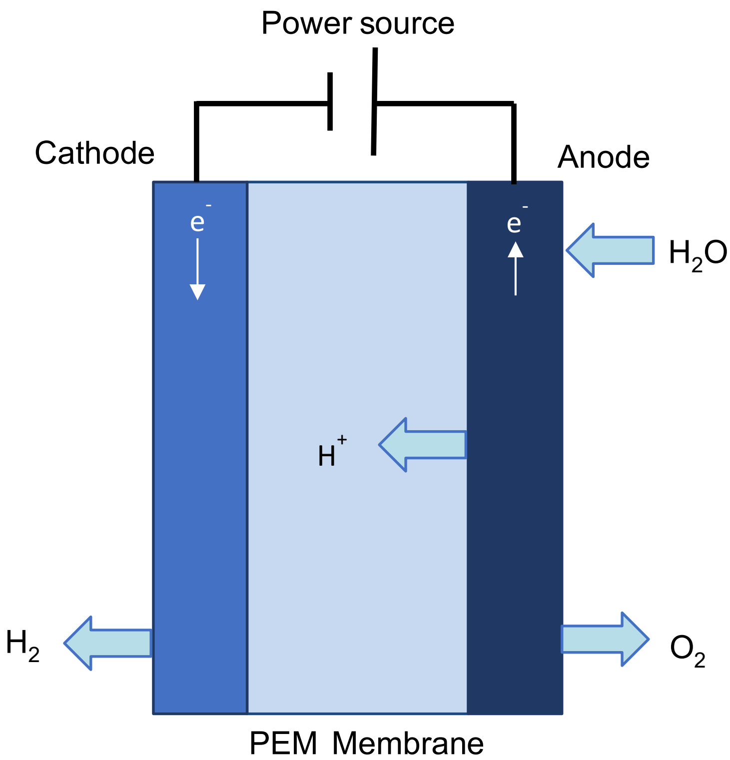

Figure 3. PEM electrolyzer components and reactions. Inspiration for illustration taken from "Hydrogen production by PEM water electrolysis – A review" by Shiva Kumar and Himabindu (2019).

Like AEL, an electrical current is used to split water molecules into hydrogen and oxygen. However, in PEM water only has to enter on the anode side of the reaction. Water is oxidized at the anode to produce oxygen as shown in Equation 5.

$$2H_2O \rightarrow 4H^+ + O_2 + 4e^- \tag{5}$$

Hydrogen ions reach the cathode side in a hydrated state to generate hydrogen gas according to Equation 6,

$$4H^+ + 4e^- \rightarrow 2H_2 \tag{6}$$

, resulting in the same overall reaction as for AEL given by Equation 7 (Shiva Kumar & Himabindu, 2019).

$$2H_2O \rightarrow 2H_2 + O_2 \tag{7}$$

During operation, the DC density is between 10 000-22 000 A/m^2. The working temperature is generally maintained at 50°C to 80°C, and the working pressure below 50 bars (Gou, 2019). The PEM technologies on the market today usually have a purity rate of 99.999 percent which means that a further purification process, as in the case for some AEL technologies, is not necessary. PEM can operate safely under high current densities which enables it to work under flexible conditions (HyBalance, n.d.).

2.3.4 Comparison between AEL and PEM Electrolyzers

Today, many different companies provide electrolyzers where the specifications of each electrolyzer differ depending on the manufacturer. For that reason, it is difficult to make over-all generalizations for the different technologies available on the market. To compare the characteristics of AEL and PEM electrolyzers, multiple sources have been reviewed and compiled which are shown in Table 1.

Table 1. A compilation of AEL and PEM electrolyzer characteristics (Gou, 2019; Ruth et al., 2017; Keçebaş et al., 2019; Buttler & Spliethoff, 2018; IRENA, 2018; Nel Hydrogen, n.d.a).

Key performance indicators	Alkaline electrolyzer	PEM electrolyzer
Component characteristics		
Electrolyte	25-30% KOH or NaOH	Solid proton exchange polymer membrane (Nafion)
Anode	Ni/Fe/Co/Cr/V	Ir/Ru
Cathode	Cr/V	Platinum
Operational characteristics		
Cell temperature [°C]	80-90	50-80
Operating pressure [bar]	≤ 32	≤ 50
Current density [A/m^2]	2000~7000	10 000~22 000
H_2 purity rate [%]	99.8-99.999	> 99.999
Efficiency		
Nominal electrical system [%]	~70	~70
System lifetime including stack replacement [yr/h]	20-30 75 000	10-30 60 000
Flexibility		
Load flexibility [%]	15-100	0-160
Min load [%]	20-40	3-10
Start-up/shut-down [sec]	60-600	1-300
Ramp-up/down [%/sec]	0.2-20	100

One of the main advantages of AEL is the maturity of the technology and the manufacturing costs are relatively low. AEL provides long-term stability and uses materials that are relatively abundant for the catalysts. The technology does however have some disadvantages such as corrosive liquid electrolyte, complicated maintenance, relatively slow-start up, low current densities, and low operational pressure. Alkaline electrolyte systems are also sensitive to rapid power changes that can harm the system and are therefore not suitable for stand-alone integration with intermittent renewable energy (Briguglio & Antonucci, 2015).

PEM has many advantages over AEL such as a relatively simple system design with fewer components, no corrosion, and being able to operate safely at higher current densities (Briguglio & Antonucci, 2015). It is also more flexible in its operation and has a fast response time (IRENA, 2018). The PEM electrolyzer can handle load-changes better than AEL, which enables it to operate dynamically to adjust to intermittent generation from renewables. However, PEM is more expensive than AEL, which is due to high-cost components such as the carbon membrane (Edvinsson, 2020) and the catalysts made of noble metals, platinum, and ruthenium. Using noble metals also makes future access uncertain because of their scarcity (U.S. Geological Survey, 2005).

In the report *Assessment of Hydrogen Production Costs from Electrolysis: United States and Europe* published in 2019, an economic evaluation was made for PEM and AEL technologies (Christensen, 2020). The evaluation was based on previous reports from IRENA (2019), IEA (2019a), Bloomberg (2019), and Glenk & Reichelstein (2019). A compilation of electrolyzer capital expenditures (CAPEX) presented in the report can be seen in Table 2. These numbers are based on future predictions by the authors, and therefore some of the cost estimations of AEL and PEM electrolyzers contradict the previous statement that AEL is currently cheaper than PEM. Electrolyzer operational expenditures (OPEX) is usually set at a value of 2 percent for large-scale electrolyzers, not including electricity costs (FCH JU, 2017; IRENA, 2018). The total electrolyzer OPEX includes electricity, water, and maintenance costs (Chrometzka et al., 2020).

Table 2. CAPEX for AEL and PEM electrolyzers as of the year 2020 according to Christensen (2020).

Source of information	AEL [$/kW]	PEM [$/kW]
Goplek et al. (2019)	571–1268	385–2068
IRENA (2019)	840	-
IEA (2019a)	500	1100
Bloomberg (2019)	600–1100	425–1400

The Hydrogen Council (2020) estimates that electrolyzer prices will fall drastically by 70-80 percent in the next five to ten years, driven by an increase in sales volumes and a decrease in the cost of renewable electricity generation. According to Schmidt et al. (2017), increased R&D funding and production scale-up will result in a 23-27 percent reduction in electrolyzer prices by 2030. These estimations align with previous studies in photovoltaics[3] (PV) price development, which finds that the main price reduction drive

[3] Photovoltaics is the conversion of sunlight into electricity by generation of voltage and electric current in semiconducting materials upon exposure to light.

for solar PV modules was increasing economies of scale (Schmidt et al., 2017). Other studies suggest that there will be a price reduction for AEL and PEM electrolyzers of 20-33 percent by 2030 (Saba et al., 2018). Smolinka et al. (2014; as cited in Saba et al., 2017) assume the cost of PEM systems will drop below those of alkaline systems during the current decade.

2.4 Hydrogen Storage

This section will present different hydrogen storage techniques followed by a comparison of these. Compression and utilization of hydrogen are two important stages in a HES and since they are directly connected to the storage they will also be introduced in this section.

2.4.1 Hydrogen Storage compared to Other Storage Technologies

Using hydrogen as storage can be preferable in many aspects. Compared to e.g. batteries, the discharge time is lower, and the storage capacity is much higher (European Commission, 2017). Hydrogen energy storage systems can store 1 GWh to 1 TWh on a large scale, while batteries typically range from 10 kWh to 10 MWh (Widera, 2020). While batteries can be suitable for short-term storage, hydrogen has the advantage of storing large amounts of energy over extended periods (Hydrogen Europe, n.d.b). A comparison between the potential of different storage technologies is illustrated in Figure 5. It can be seen that hydrogen has the highest capacity and longest discharge rate of all storage types.

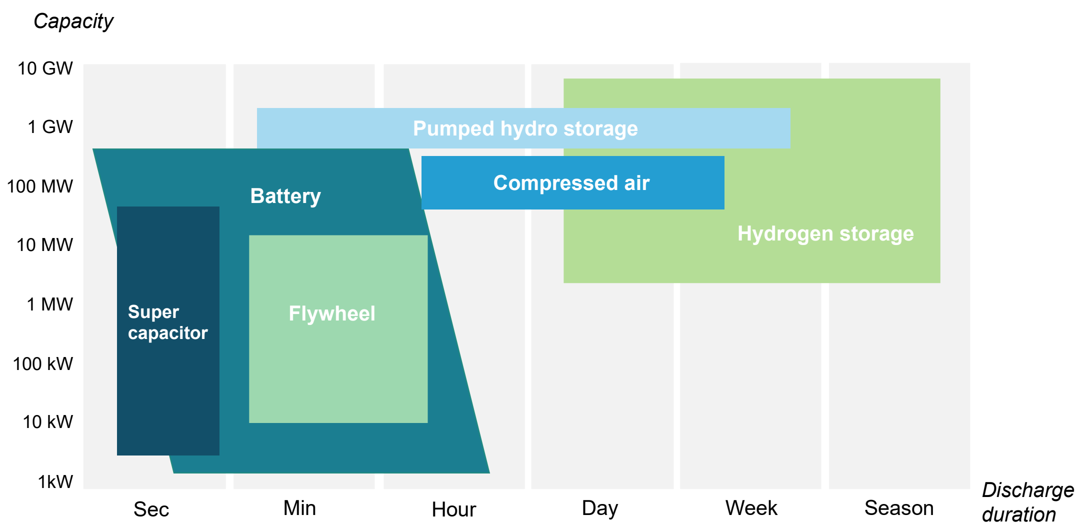

Figure 5. Illustration of different storage technologies and properties in capacity and discharge duration periods. Inspiration from an illustration from the report "How hydrogen empowers the energy transition" by Hydrogen Councils (2017b).

2.4.2 Hydrogen Storage Technologies

There is a vast multitude of possible options when it comes to hydrogen storage. According to Andersson and Grönkvist (2019), hydrogen storage technologies can be divided into three main categories as listed below.

- Hydrogen is stored in pure form without physical or chemical bonding with other materials in gaseous or liquid form.
- Hydrogen molecules are adsorbed onto or into a material, then held together by a weak physical van der Waals[4] bond.
- Atomic hydrogen is stored through a chemical bond through absorption in metal or chemical hybrids.

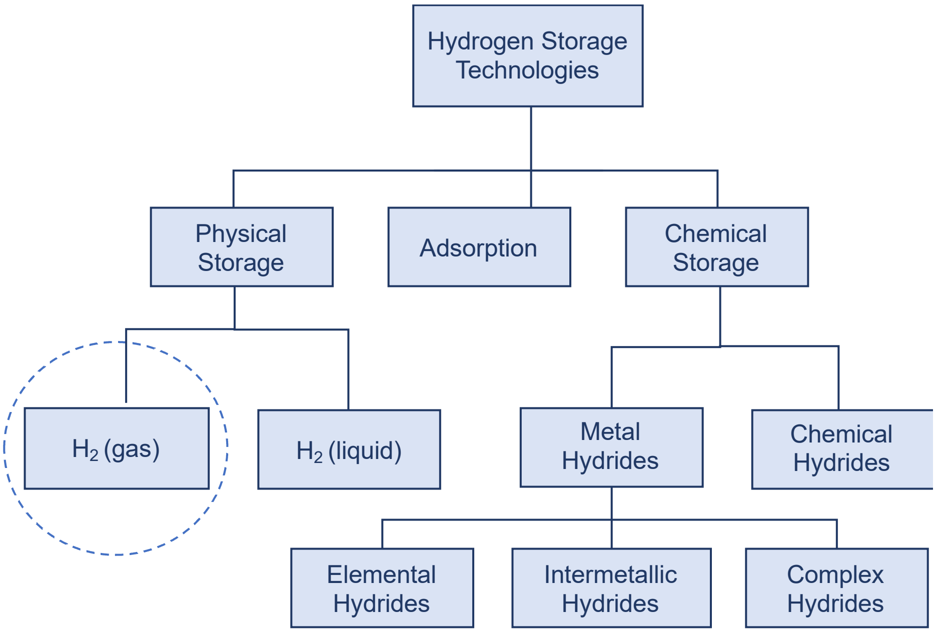

Figure 6. Different hydrogen storage technologies. The circled box, H_2 gas, will be of focus in this study which will be motivated later in this chapter. Inspiration to illustration taken from the report "Large Scale Storage of Hydrogen" by Andersson and Grönkvist (2017).

The storage of pure hydrogen can be achieved in gaseous or liquid form. Storing hydrogen as a liquid requires low temperatures below its boiling point which in atmospheric pressure is -253°C. Liquid hydrogen at atmospheric pressure, 1 bar, contains about three times more energy per volume unit than compressed hydrogen in gaseous form at 350 bar. However, the process to achieve this low temperature consumes approximately 25-35 percent of the original energy content (Damman et al., 2020). Storing liquified hydrogen also suffers unavoidable evaporative losses over time known as "boil-off", due to heat leak through the mechanical support (Andersson & Grönkvist, 2019). The cooling process to liquefy the gas also requires a lot of energy, which lowers the overall efficiency. Due to the associated losses and complex cryogenic cooling process for liquid hydrogen, it is not suitable for long-term large-scale storage systems (Pimm et al., 2019). Liquid hydrogen is, however, according to Abdin and Khalilpour (2018), required for a large-scale export of pure hydrogen. With increasing transport distance, liquid hydrogen becomes more cost-effective than gaseous hydrogen because the same volume contains a much higher energy density (Steen, 2016).

[4] Van der Waals force are relatively weak electric forces that attract neutral molecules to one another in gases (Britannica, n.d.)

Storing hydrogen in gaseous form requires two main components – a storage compartment and a compressor to achieve higher storage pressure and increase the storage density. Gaseous hydrogen is usually not stored in pressure exceeding 100 bar in vessels above ground and 200 bar for underground storage (Wolf, 2015). The low density of hydrogen leads to the requirement of large storage volumes, and as a consequence, usually large investment costs. However, higher pressure e.g. 700 bar requires advanced vessel materials such as carbon fiber, which makes it very expensive and not considered viable for large-scale applications (Andersson & Grönkvist, 2019). One of the main advantages of storing hydrogen as compressed gas compared to liquid hydrogen is that most applications for hydrogen today require hydrogen in gaseous form. Having storage with compressed gas gives the ability to rapidly access the energy source, e.g. for refueling fuel cell vehicles (Stetson et al., 2016). According to Damman et al. (2020), the current retail price of compressed hydrogen is approximately 9 € per kg while the retail price for liquid hydrogen is about 15 € per kg. That is, from a financial perspective liquid hydrogen is not competitive with gaseous hydrogen (Damman et al., 2020). However, for the hydrogen economy to thrive both stationary and mobile storage systems are needed, and therefore hydrogen in both compressed gaseous form and liquid form is necessary (Abe et al., 2019).

Apart from storing hydrogen in pure form, hydrogen can be stored in fuels or chemicals such as methanol after reaction with carbon dioxide or ammonia after reaction with nitrogen (Swedish Hydrogen Development Center, n.d.). Hydrogen can also be stored in the form of metal hydride by a bond with powdered metals. However, the high temperatures, energy required, and slow kinetics involved is a problem for reversible storage. As of today, the technology is not efficient enough to compete with liquid or compressed hydrogen storage (Damman et al., 2020).

2.4.3 Compression of Hydrogen

Before hydrogen can be stored, compression is often needed. This is because the energy density of hydrogen increases with pressure, which enables storing larger volumes of hydrogen (Guo et al., 2019). The relation between pressure and volume for gas compression can be described using Boyle's law (Encyclopaedia Britannica, n.d.), shown in Equation 8,

$$P_1V_1 = P_2V_2 \tag{8}$$

, where P represents the pressure of the gas and V is the volume. The energy needed to compress gases and the compression work depends on the thermodynamic compression process, as well as on the nature of the gas (Encyclopaedia Britannica, n.d.). There are mainly three different methods that can be used for compression in a hydrogen energy system. The first option is to use an external compressor and the second is to use a pressurized electrolyzer. A pressurized electrolyzer works at lower pressure levels, usually between 15 to 50 bars. The last alternative is applying a combination of the two systems (Godula-Jopek, et al., 2015). The cost of external compressors varies depending on the scale of the system, where larger compressor capacity results in higher CAPEX but a lower CAPEX rate (Christensen, 2020). A general compilation regarding cost information of different compressor capacities can be viewed in Table 3.

Table 3. Prices for compressors of different capacities, estimated Capex, and energy consumption (Christensen, 2020).

Capacity [kg/year]	CAPEX [$]	CAPEX Rate [$/kg]	Energy [kWh/kg]
1 168 000	3 888 840	3.32	0.399
16 940 240	16 989 074	3.05	0.399
38 663 759	38 775 217	2.94	0.399

2.4.4 Underground Storage

For large-scale storage, implementations for compressed gas underground have been proven to be the most cost-efficient alternative (Swedish Hydrogen Development Center, n.d.). The investment costs are significantly higher for aboveground vessels for large-scale storage. The most frequently used techniques for underground storage of hydrogen are using salt caverns, depleted gas fields, and natural aquifer formations (Amid et al., 2016).

In the report *Benchmarking of Selected Storage Options* by Kruck and Crotogino (2013), different solutions for underground storage as a part of the HyUnder project funded by the European Union were evaluated and benchmarked. The different storage options were ranked based on a number of factors – safety, technical feasibility, investment and operational cost and static and dynamic stability. Based on these factors, using salt caverns was ranked the best hydrogen underground storage option. The second-best alternative was storage in depleted gas fields which is the most commonly used method for hydrogen storage today, and third was storage in aquifer formations. However, a common prerequisite for these storage options is the requirement of geographical availability. The study ranked lined rock cavern (LRC) as the fourth-best solution. This technique is a suitable option for countries that lack the geographical conditions of the former mentioned storage options and is optimal for countries that have access to large areas of homogenous hard rocks that can withstand high pressure, such as Scandinavian countries (Kruck & Crotogino, 2013). For a country like Sweden, which lacks the geographical possibility of hydrogen storage in salt caverns, depleted gas fields, and aquifers, LRC becomes highly interesting.

A LRC is typically designed as a cylindrical vertical cavern with a relatively thin metal-lining enclosing the gas. A concrete layer is used as a base for the lining and as a load transfer medium between the gas pressure forces and the surrounding rock (Sofregaz US Inc., 1999). One of the major advantages of this technique is that the hydrogen only comes in contact with the steel lining, and the risk for contamination is therefore low. Storing hydrogen in LRC is a relatively new technique where the integrity of the hydrogen only relies on the pressure-tight lining of welded metal (Kruck & Crotogino, 2013). Research and development in LRC have been around in Sweden since the 1980s and in 2002 the world's first large-scale demonstration plant became operational in Skallen, located near Halmstad in the south-west of Sweden (Johansson et al., 2018). The storage facility is used for storing natural gas as a part of commercial operations in the Swedish gas grid (Swedegas AB, 2015).

The Skallen storage facility is located approximately 150 m below ground. The cavern has a geometrical volume of 40 000 m^3 with a total storage capacity of 10 000 000 Nm^3 gas at a maximum pressure of 200 bar, which is equivalent to approximately 29.9 GWh of energy utilized in a fuel cell (Johansson et al., 2018). The vertical cylinder shape of the cavern, with rounded top and bottom, is of great importance for the storage of compressed gas. A smaller area of the upper surface puts less pressure on the bed-rock and allows it to withstand a higher pressure (Nordlander, 2020). The Skallen design has been an inspiration for different projects and was recently adapted for the LRC currently under construction for the HYBRIT project. The total cost of the HYBRIT LRC is estimated to be 200 million SEK of which 50 million has been subsidized by the federal agency Energimyndigheten (Vattenfall, 2019). An illustration of the Skallen LRC can be seen in Figure 7.

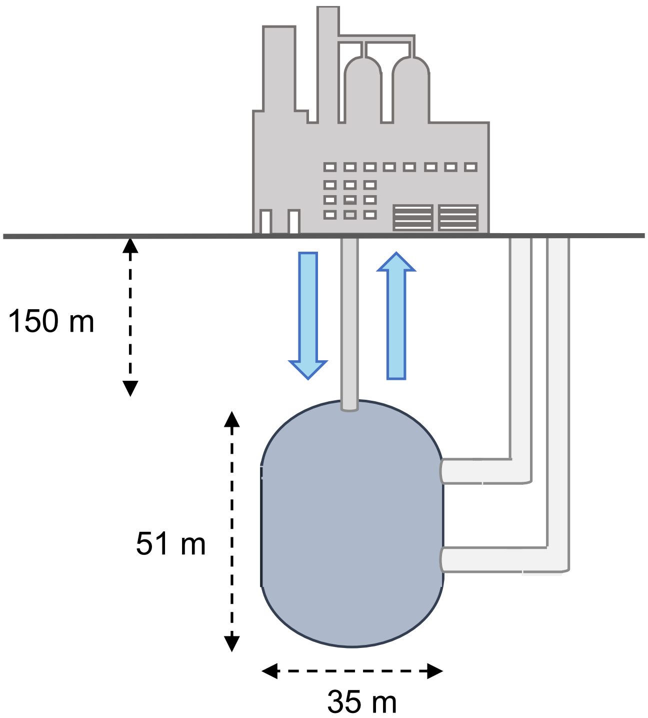

Figure 7. Illustration of the underground storage Skallen. Observe that the dimensions in the illustration are not proportional. Inspired by "Figure 3. Vertical section and basic data of the demo plant at Skallen in the south-west of Sweden. (© Johansson, 2003, with permission)." by Johansson et al. (2018).

2.4.5 Storage Above Ground

In regions without suitable geological prerequisites for underground storages, another option is implementing storage systems above ground (Andersson & Grönkvist, 2019). According to Godula-Jopek et al. (2015), there are mainly four different types of cylinders for hydrogen storage above ground. The most commonly used cylinders, called type l, are made from stainless steel or aluminum. They are usually not operated at a pressure exceeding 200 bar but are available in nominal pressures up to 300 bar. The downside of type 1 cylinders is that they are heavy. Type ll cylinders use a thin metal liner which decreases the weight of the vessel but also increases the price. They are commercially available in nominal pressures from 200 to 300 bars. Type lll storage vessels are made from carbon fiber with a metal liner for gas tightness and type lV, also made from carbon fiber, have a synthetic liner. Both type lll and lV can operate at nominal pressures ranging from 350-700 bars. Type IV can be used up to 30 years without replacement which is twice the expected lifetime of type I & II (NPROXX, n.d.).

Hydrogen storage in vessels have some advantages over underground storages as they ensure stability and high purity, provide easier access to the storage and they can be installed independently of the location. Vessels above ground are preferable for small-scale storage (Swedish Hydrogen Development Center, n.d.), but can also be applied for large-scale systems. There is however little experience with large-scale hydrogen storage in metallic vessels, but it's a relatively common practice for the storage of natural gas (Andersson & Grönkvist, 2019).

2.4.6 Utilization of Hydrogen

Utilization is the final stage in the HES chain, and at this stage there are two main options – the hydrogen can either be utilized onsite or be transported. Utilization onsite is more preferable than transporting the hydrogen in terms of energy losses and a reduction in transportation costs (Singh et al., 2015). For utilization onsite, several components are needed to be introduced which can be seen in Figure 8. First, hydrogen is extracted from the storage and if it is a low-pressure storage, the hydrogen needs to be further compressed. The gas can then either be stored in an intermediary storage or be directly transferred into the pre-cooling system in connection to the dispenser. The pre-cooling system ensures that the tank does not heat up above 85°C during refueling. Lower temperatures allow faster refueling but also result in higher energy consumption. The refueling is carried out using a dispenser which is designed for the pressure of the hydrogen tank, generally 350 or 700 bars (Hydrogen Europe, n.d.c).

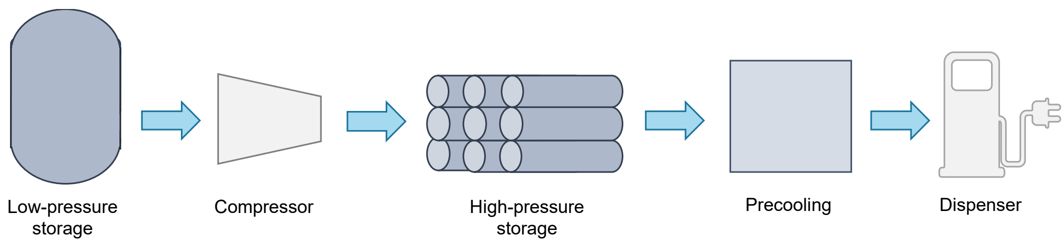

Figure 8. Schematics of an onsite distribution system. Inspiration for illustration acquired from Hydrogen Europe, n.d.c.

According to Reddi et al. (2017) the relative costs of the different components in the utilization stage, including equipment such as compressor, dispenser, control, and pre-cooling system, vary with the size of the refueling station. The larger the system, the larger the cost of the compressor is relative to the other components (Reddi et al., 2017).

2.5 Offshore Wind Energy

Offshore wind energy is a rapidly growing source of electricity production. There has been an annual growth of about 30 percent since 2010 and more than 150 new offshore wind projects are scheduled to be completed worldwide by 2024. One major advantage of offshore wind power is the high capacity factor[5] which can stretch from 40 to 50 percent. This both exceeds the capacity factor of onshore wind power and is around twice as high as for PV power. Offshore wind power also tends to have lower hourly variability than both photovoltaics and onshore wind power. Seasonal variation is another factor considered to be in favor of offshore wind power where it, in the northern hemisphere, tends to produce more electricity during the winter months which coincides with the higher electricity consumption during those months. Based on these characteristics, the IEA wants to classify offshore wind power as a unique category of electricity production technologies, a variable baseload[6] technology (IEA, 2019b).

Offshore wind technology has developed rapidly during the last years and as a consequence there has been an increase in the sizes of wind power plants. In 2010 the most developed offshore wind power plants had a tip height of approximately 90 meters whereas in 2016 the tip height can reach above 160 meters. Larger turbines have a larger rotor diameter and because wind speeds increase with higher altitudes this enables the turbines to capture more wind and generate more power. The average rated capacity of the installed turbines has increased from 3MW in 2010 to almost 6MW in 2018 which also has led to an increase in capacity factor of about five percent. The industry has targeted to develop even bigger turbines of 15 to 20 MW rated capacity by 2030 (IEA, 2019b). IEA has developed a reference offshore wind turbine with the capacity 15 MW where the rotor has a diameter spanning over 240 meters and the center of the rotor is at a height of 150 meters (Bredmose, 2020). The increase in size has led to increased capital costs but also to reduced operational costs and maintenance costs, ultimately leading to a lower levelized cost of electricity. The evolution of wind turbines from 2010, as well as future predictions of sizes and capacity, can be seen in Figure 9 (IEA, 2019b).

[5] The capacity factor of a wind turbine is the average power output divided by the maximum power capability (Nmpp Energy, n.d.).

[6] Baseload technology refers to energy sources that can provide constant electricity production to meet the minimum demand (Energy education, 2020).

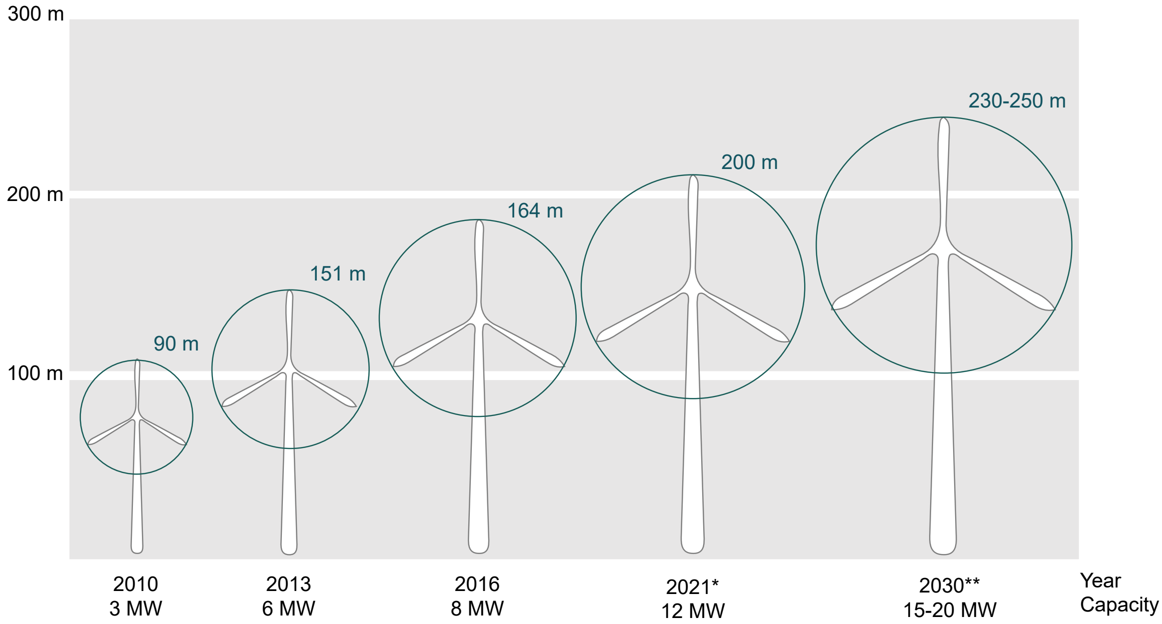

Figure 9. Evolution of the largest commercially available turbines.
** Announced expected year of commercialization. ** Further technology improvements through to 2030. Inspiration to illustration from International Energy Agency (2019b) report "Offshore Wind Outlook 2019".*

According to the report *Havsbaserad vindkraft potential och kostnader* prepared on behalf of the Swedish Energy Agency, the technical potential of offshore wind energy in Sweden equals an electricity production of 3000 TWh per year, if all suitable areas would be exploited. Sweden has one of the longest coastlines in Europe, mainly towards the Baltic Sea, and with that comes a high potential for implementing offshore wind farms (Ståhle et al., 2017).

2.6 The Swedish Electricity Grid and Market

The Swedish electricity grid can be divided into three levels. Long-distance bulk movement of electricity goes through the high voltage transmission grid. The second level is the regional transmission grid where electricity is transported from the high voltage transmission grid to the local grid, distributing electricity to end-consumers (Energimarknadsinspektionen, 2019). The majority of the electricity is produced in the northern parts of Sweden whereas the main electricity consumption takes place in the south. To cope with limitations and bottlenecks in the electricity grid, Sweden is divided into four bidding areas. The two northernmost bidding areas, SE1 and SE2, typically have a surplus of electricity resulting in lower electricity prices whereas the two southernmost bidding areas, SE3 and SE4, have a deficit of electricity resulting in higher prices (Energimarknadsinspektionen, 2019).

There is currently a large expansion of renewable energy sources in Sweden, which is likely to affect the future flow of electricity and electricity prices. Other countries, eg. Germany and Denmark, which have a higher share of intermittent electricity production than Sweden also have more volatile electricity prices (SVK, 2015). Future predictions indicate that Swedish electricity prices will move towards the same trend (Energimarknadsbyrån, 2021), and become more volatile as a result of growing wind power and the phasing out of nuclear power (Energimyndigheten, 2019b). A comparison between the Swedish and Danish electricity prices is presented in Figure 10. As can be seen, Denmark has more fluctuations compared to Sweden and lower electricity prices, at times even negative.

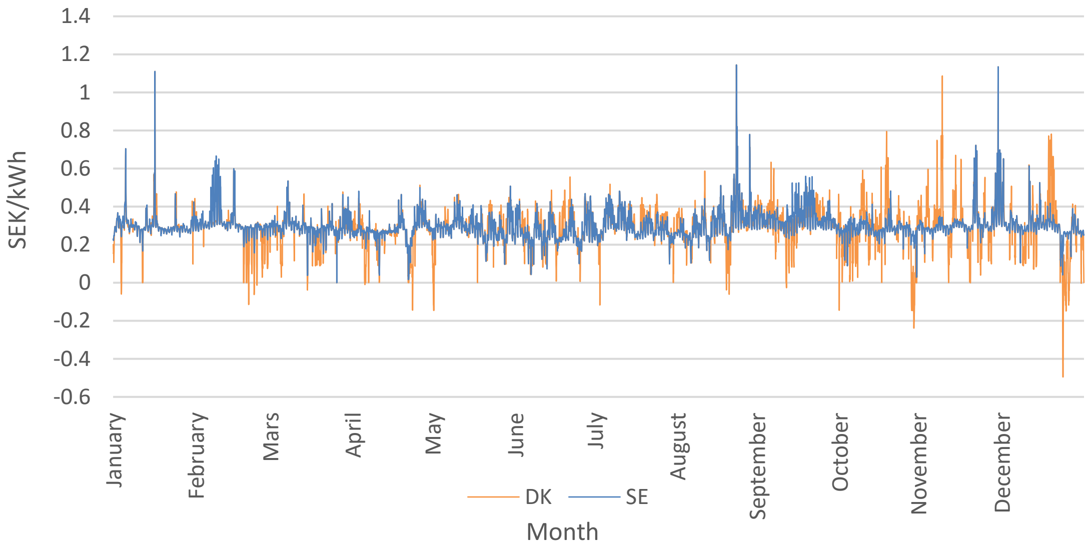

Figure 10. Swedish and Danish electricity prices (SEK per kWh) the year of 2017.

The Swedish wholesale electricity market is an energy-only market which means that electricity is traded in kWh. It's a part of the integrated Nordic and Baltic electricity market. The market can be divided into four submarkets. These are the hedge market, the day-ahead market, the intraday market, and the electricity balancing market (Energimarknadsinspektionen, 2019). At the day-ahead market, also referred to as the spot market, the electricity is traded in order to plan for the production and delivery of electricity the following day. In the Nordic and Baltic countries this takes place on the Nord Pool power market which is owned jointly by the respective Transmission System Operators (TSO) in the member countries. The trading starts with all actors submitting their sell and buy bids. The sell-bids present how much electricity the producers are willing to sell to a certain price and the buy-bids how much the electricity trading companies, and the big industrial companies are willing to pay for certain volumes of electricity. Based on where these bids meet, a final price is set and the actors are then obliged to produce and consume what has been agreed upon (Energimarknads-inspektionen, 2019).

The intraday market is an adjustment market where it is possible for the actors to trade-in balance if the conditions have changed since the closing of the day-ahead market (Energimarknadsinspektionen, 2019). The balancing market is organized by Svenska kraftnät and the other national TSO's of the Nordic and Baltic electricity market with the purpose of securing real-time regulation possibilities for frequency control and voltage regulation. The balancing market is divided into marketplaces for automatic and manual production reserves (Energimarknadsinspektionen, 2019).

Some factors that affect the supply and demand and thereby the electricity price is the cost of carbon emissions, the prices of natural gas, coal, and oil as well as weather-related conditions. Cold temperatures result in an increase of electricity consumption and higher electricity prices whereas warm weather usually leads to lower electricity prices. During times with favorable wind conditions the power production from wind plants will go up, resulting in a decrease in electricity prices. Another important factor that has an impact on the electricity prices in Sweden is the water level in the hydroelectricity dams, where a high level leads to low electricity prices and vice versa (Fortum, 2019).

2.7 Taxes and Tariffs

In Sweden, there is an energy tax on electricity produced and consumed. Electrolytic processes are however exempted from taxes (Skatteverket, 2020a). Value-added tax (VAT) is a tax paid when buying goods and services. However, the VAT is something that the producer of the goods charges the end-use customer and passes on to the tax agency (Skatteverket, 2020b) The net cost for the producer of the VAT is, therefore, zero and typically not accounted for in financial calculations. When connecting a larger facility consuming or producing electricity to the grid, a connection fee has to be paid to the TSO. This fee is based on the additional costs for the TSO in order to connect the new facility (SVK, n.d.). Since there are many uncertainties regarding this cost it was not accounted for further in the study.

2.8 Levelized Cost of Hydrogen

Levelized cost of energy is a measurement used to assess and evaluate the costs of different methods of energy production. The parameters used for calculating the LCOE of an energy system are investment costs, operation costs over an assumed lifetime, interest rate and electricity prices. The LCOE can be used as an indicator of the average minimum price of the energy generated in order to offset the total cost of production over the system's lifetime (Corporate Finance Institute, n.d.). The LCOE can be calculated using Equation 9,

$$LCOE = \frac{\sum_{t=1}^{n} \frac{CAPEX_t + OPEX_t}{(1+r)^t}}{\sum_{t=1}^{n} \frac{E_t}{(1+r)^t}} \tag{9}$$

, where E represents the energy produced by the system in MWh, r is the interest rate, n is the lifetime of the system and t represents the year after operation starts. When calculating the LCOE of a HES, the same equation is used but the energy produced (E) is replaced by kg of hydrogen produced (m). This is then referred to as LCOH, the Levelized Cost of Hydrogen, and can be seen in Equation 10.

$$LCOH = \frac{\sum_{t=1}^{n} \frac{CAPEX_t + OPEX_t}{(1+r)^t}}{\sum_{t=1}^{n} \frac{m_t}{(1+r)^t}} \tag{10}$$

3. Case Studies

This chapter will present and explain the two case studies conducted for the purpose of the thesis. The first case study was of a system with hydrogen production and storage linked to grid-connected offshore wind farms outside Gävle. The second case study was of two independent hydrogen refueling stations on different locations in Sweden, Södertälje and Sundsvall, where the power for the hydrogen production was supplied by the electricity grid.

3.1 Hydrogen Energy System in Gävle Hamn

This section starts by giving an overview of the simulated system in Gävle Hamn. The case study was divided into three cases where different hydrogen production technologies, electricity sources, storage options and demand scenarios were investigated for each case. In the next section, the projected offshore wind farms outside Gävle Hamn from which electricity for the hydrogen production was utilized are presented. The third section describes the operations in Gävle Hamn and the plans of implementing a HES in the port. Lastly, the different storage options available in Gävle Hamn are presented.

3.1.1 Overview of the System

The purpose of the first business case was to investigate how hydrogen production and storage could be optimized in a system connected to offshore wind farms outside Gävle. The hypothetical hydrogen production and storage facility was located in the industrial port Gävle Hamn, relatively close to the projected wind farms. The hydrogen demand for this case was based on the transport and machinery in the port that today is run on diesel. This to investigate how a HES could help decarbonize the operations. The field study was further divided into three cases. In the first case, wind power from the projected wind farms was the only power source for the HES. In this case, PEM technology was used for electrolysis as it introduces the possibility of flexible regulation that can adjust to the intermittency of wind power production. PEM electrolyzers were also used in the second case, but the power was supplied from both the electricity grid and the wind farms. This introduced the possibility to produce hydrogen even when weather conditions were unfavorable and wind power production was low or nonexistent. Also, during periods of high electricity prices, the hydrogen production could be scaled down to avoid high production costs and the wind electricity could instead be sold to the grid. When electricity prices were low and wind power production was high, hydrogen production could be scaled up to take advantage of these favorable conditions. In the last case, the power was also supplied by electricity from the grid and wind, but AEL technology was used for the hydrogen production instead of PEM. This to investigate the financial impacts of having a cheaper electrolyzer at the expense of having access to flexible hydrogen production. Since the AEL technology lacks the ability to regulate the hydrogen production and adjust to unfavorable electricity prices and weather conditions, but on the other hand implies lower investment costs than PEM, it was of interest to see how this would affect the LCOH. It was also of interest to see how the share of electricity from offshore wind varied depending on the chosen electrolyzer technology. Schematics of the HES for the three cases are presented in Figures 11-13.

Figure 11. Schematics of the HES with PEM electrolyzer and power supply from wind farms.

Figure 12. Schematics of the HES with PEM electrolyzer and power supply from wind farms and the electricity grid.

Figure 13. Schematics of the HES with AEL and power supply from wind farms and the electricity grid.

Each production case was further divided into three demand cases. Since the transition to 100 percent of the machinery and transport in Gävle Hamn being fueled by hydrogen is likely to happen in stages, demand cases of 15 percent and 50 percent of the operations in Gävle Hamn were introduced. For each hydrogen production case, different storage alternatives were investigated which will be further explained in section 3.1.4.

3.1.2 Wind Farms

The planned offshore wind farms will be located outside the coast of Gävle. Today there are three large wind farms projected by Svea Vind Offshore in this area called Utposten 1, Utposten 2, and Gretas Klackar 2. An illustration of these can be seen in Figure 14.

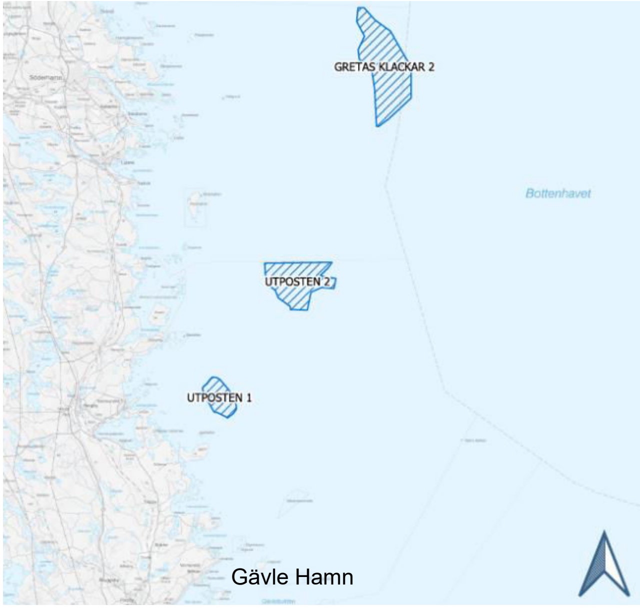

Figure 14. Projected wind farms outside the coast of Gävle. Map retrieved from Svea Vind Offshore (2020).

The planned installed capacity of the wind farms depends on the size of the wind turbines, which has not yet been decided. According to Karl Lindblad (2020), Project Developer at Svea Vind Offshore, it is however likely that the projected wind turbines will have power capacities of 15 MW. The total installed wind capacity of each wind farm is expected to be between 200 to 600 MW (Svea Vind Offshore, 2020). Due to the uncertainties of the installed capacities of the projected wind farms, this study will simulate four hypothetical wind farms of sizes 50 MW, 200 MW, 450 MW and 600 MW. 50 MW is a relatively small capacity for an actual offshore wind farm. It is however of interest to compare how different sizes affect the hydrogen system both financially and technically.

3.1.3 Gävle Hamn

Gävle Hamn is the largest container port on the Swedish East Coast and an intermodal logistic hub for import and export. The export mainly consists of bulk materials such as wood and steel and the import is predominantly raw material for various industries. The operations in Gävle Hamn, which includes approximately 40 different actors, are coordinated by the port authority Gävle Hamn AB. The operations in Gävle Hamn consist of handling, storing, loading, unloading, and transporting cargo. In the daily operations, multiple material-handling machines are used in addition to the trucks delivering goods to the port. (Gävle Hamn, 2020)

In 2019, an investigation started to review the possibilities of implementing hydrogen infrastructure in the port. The investigation is a collaboration between Gävle Hamn AB, Gävle Energi, and Statkraft. A pre-study has already been conducted that aimed to define practical, commercial and legal conditions as a basis for possible future investments. Other parameters that are currently under investigation are locations for a hydrogen production facility and storage, access to electricity and water, possible applications for access heat and grid-network capacity (Gävle Hamn, 2020). The aim, if a HES is to be implemented, is to facilitate green transports to and from the port,

decarbonize the operations in the port and create a possibility for better energy management in the port area.
(Astner, 2020).

3.1.4 Storage Options

In Gävle Hamn there are six underground storage units, used presently for storing petroleum products. One of the six units consists of three so-called ships (interconnected chambers) and one unit consists of two ships, adding up to a total of nine units. The locations and denotations of the storage units can be seen in Figure 15. Technical data and details for the units are presented in Table 4.

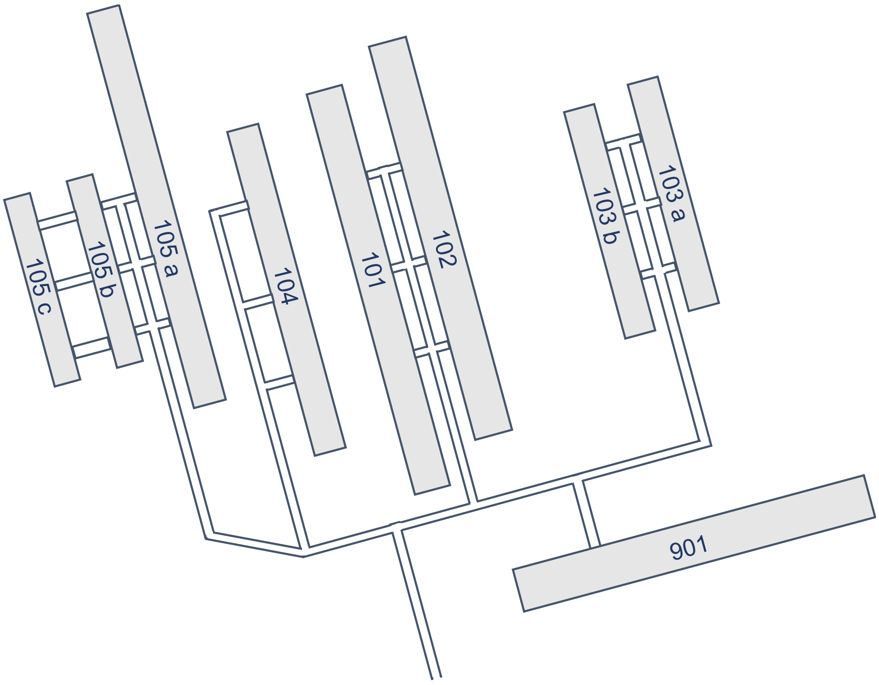

Figure 15. Locations and denotations of the underground storage units in Gävle Hamn. Illustration inspired by schematics retrieved from Rosengren (2020).

Table 4. Technical data for the storage units in Gävle Hamn (Rosengren, 2020).

Unit	Storage capacity [m^3]	Depth below ground upper edge [m]	Depth below ground lower edge [m]
101	100 000	27.5	51.5
102	100 000	27.5	51.5
103 a+b	142 000	27.5	51.5
104	100 000	27.5	51.5
105 a+b+c	220 000	27.5	51.5
901	90 000	28	60

In order to use these units for compressed hydrogen storage, they need to be converted into LRC. Repurposing already existing underground units could possibly result in lower investment costs compared to the alternatives of constructing a new LRC or implementing vessels above ground and is therefore an option worth investigating. Unit 901, with a volume of 90 000 m^3, was chosen for this study. The reason was that it was large enough to store the hydrogen demand while cheaper than repurposing the larger units.

A schematic of the system with the repurposed underground LRC storage and the flow of hydrogen is shown in Figure 16. The facility above ground represents the electrolyzers, compressor, and other components.

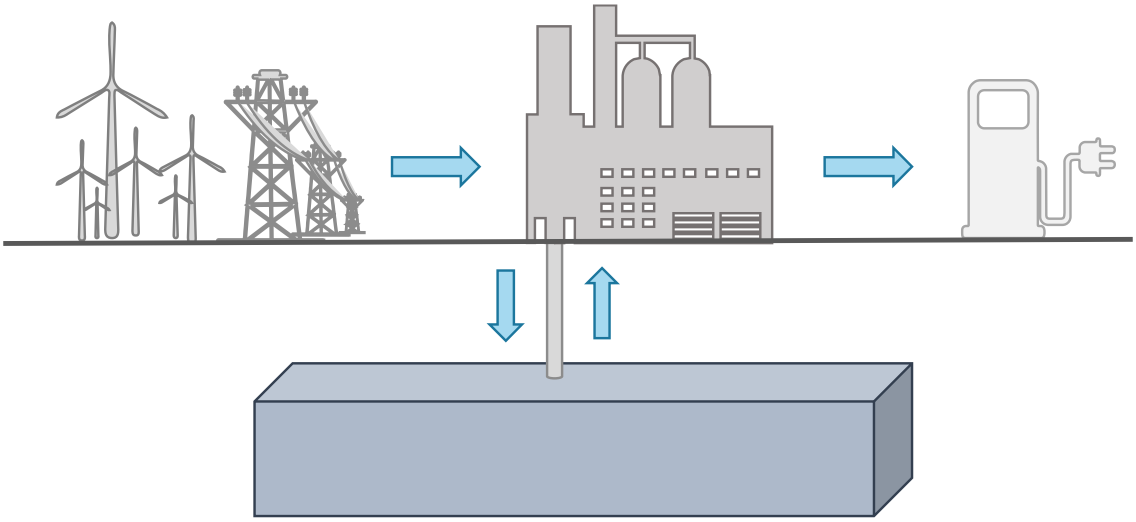

Figure 16. Hydrogen production system with underground LRC storage.

The second alternative examined for hydrogen storage in Gävle Hamn was construction of a new LRC like the one in Skallen. The advantage of constructing a new cavern is that it can be designed optimally for a specific purpose and hydrogen demand. A schematic of the system with a new underground LRC storage and the flow of hydrogen is shown in Figure 17.

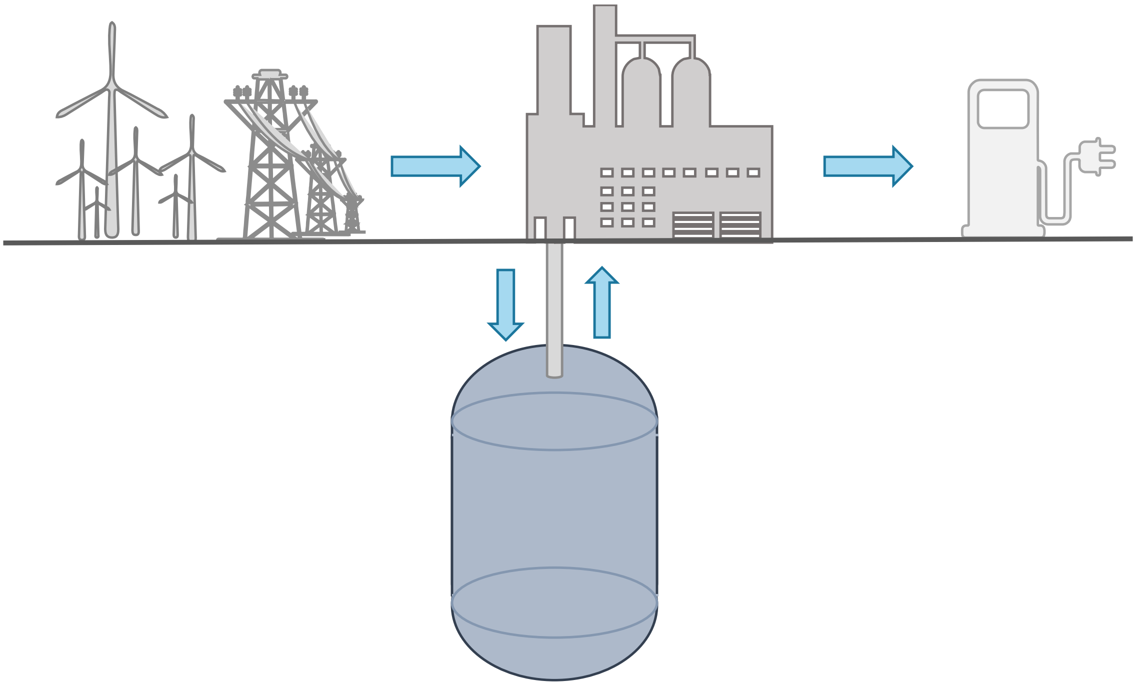

Figure 17. Hydrogen production system with new LRC underground storage.

The third hydrogen storage option examined was to use vessels above ground. This could possibly be the cheaper alternative for smaller hydrogen demand scenarios and something of interest to investigate. Vessels above ground also have advantages such as easier access to the storage and it can be installed independently of the geological conditions unlike the underground storage alternatives. A schematic of the system with vessels above ground and the flow of hydrogen is shown in Figure 18.

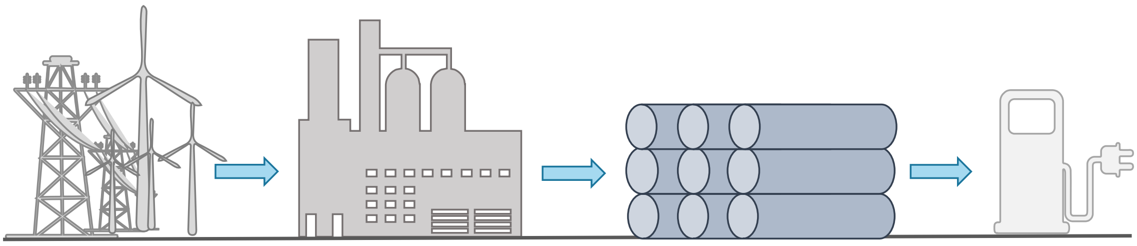

Figure 18. Hydrogen production system using vessels above ground as storage.

3.2 Grid-connected Independent Hydrogen Refueling Stations

This section starts by giving a brief overview of the simulated independent refueling stations in Södertälje and Sundsvall. The next section describes the chosen locations for the stations and traffic. Lastly, the storage option for the two cases is presented.

3.2.1 Overview of the System

The second case study was of two hypothetical independent hydrogen refueling stations on two different locations in Sweden, Södertälje and Sundsvall. Like the case in Gävle Hamn, both AEL and PEM electrolysis systems were investigated to compare the financial aspects of either having a lower electrolyzer investment costs with a constant production rate using AEL or a flexible regulation that PEM provides. Unlike the system in Gävle Hamn, electricity from the grid was the only power source used for the hydrogen production. The reason for this was to investigate how the exclusion of wind power would affect the systems behavior and how a production based solely on electricity prices would reflect on the LCOH. Different demand cases were evaluated to reflect a gradual hydrogen transition of the road-transport. The daily demand of hydrogen at the two locations were based on previous research and heavy-duty traffic at the locations, which will be presented in section 3.2.2 and further explained in methodology, section 5.1.3. The only storage option investigated for the two refueling systems was vessels above ground, which will be motivated in section 3.2.3. Schematics of the HES for the two production cases in Södertälje and Sundsvall can be seen in Figures 19 and 20. The production and utilization of hydrogen was onsite.

Figure 19. Schematics of the HES with PEM electrolyzer and power supply from the electricity grid.

Figure 20. Schematics of the HES with AEL and power supply from the electricity grid.

3.2.2 Location and Traffic

Two locations in Sweden were investigated, where one refueling station was situated outside the city Sundsvall, and the second refueling station was outside the city Södertälje. These two locations were chosen because they are heavily trafficked by heavy-duty vehicles. Sundsvall is a connection point of motorways E4 and E14 and according to data acquired from Trafikverket, approximately 800-1200 heavy-duty vehicles traffic this road on a yearly everyday average. Södertälje has both highways E4 and E20 passing through the city with approximately 3990 heavy duty vehicles per day. (Trafikverket, 2020) The locations of the refueling stations are also advantageous because there are no hydrogen refueling stations close to the sites today. Sundsvall is located between the hydrogen refueling stations in Umeå and Sandviken and would therefore be a strategic connection point for traffic between these regions, as well as potential traffic from Norway. The closest hydrogen refueling stations to Södertälje is Arlanda approximately 75 km north and Mariestad 270 km south-west.

Another reason for choosing these two locations is because they are in two different electricity price areas. Sundvall is located in the electricity price area SE2 and Södertälje in SE3, see Figure 21. Since the hydrogen production was powered by electricity from the grid, it was of interest to see how different electricity prices would affect the final price of hydrogen.

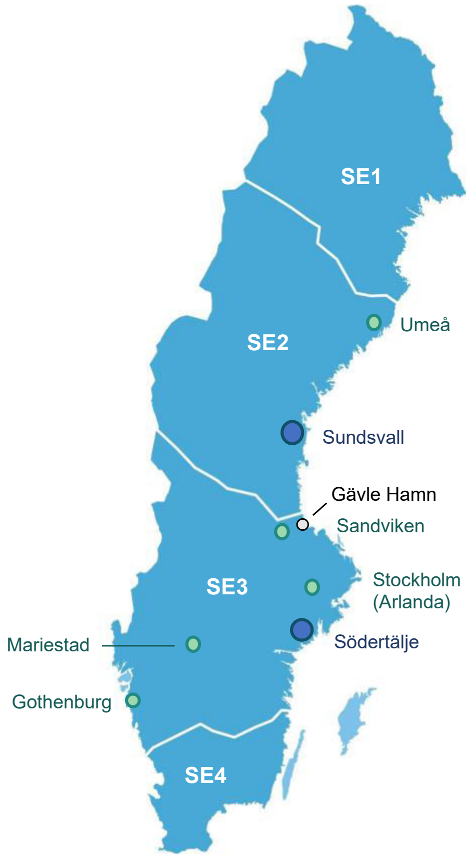

Figure 21. Map of Sweden with existing hydrogen refueling stations represented in green circles and the hypothetical refueling stations investigated represented in blue circles. Sweden's electricity price areas (SE) are separated by white lines. Inspiration for illustration from Vätgas Sverige (n.d.) and map obtained from Energimyndigheten (n.d.).

3.2.3 Storage Options

The storage option chosen for the refueling stations was vessels above ground. This was mainly due to the uncertainties of geological conditions close to the hypothetical refueling stations for constructing a new LRC as well as already existing underground storage units at the chosen sites. Therefore, storing hydrogen in vessels above ground was considered the only reasonable storage alternative. A schematic of the system with vessels above ground and the flow of energy is shown in Figure 22.

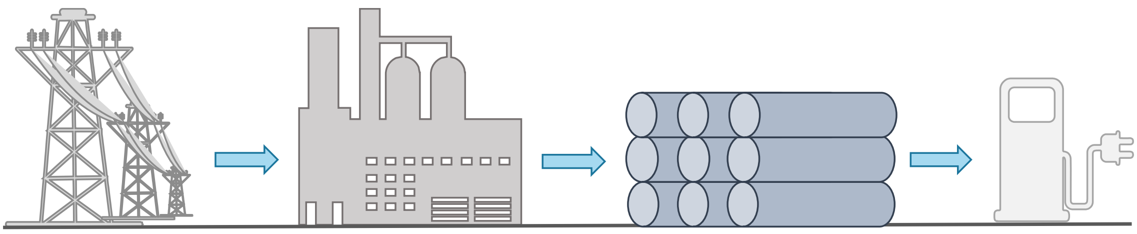

Figure 22. The hydrogen production system with vessels above ground as storage and power supply from the electricity grid.

4. Data

This section presents the data acquired from research, meetings and e-mail contact with persons with experience in the hydrogen industry and representatives from Gävle Hamn. Each section presents the specifics of the data sets and how it was gathered. The data was then pre-processed before being used in the simulations which will be explained in chapter 5, methodology.

4.1 Electricity and Wind Data

Electricity prices were gathered from Nord Pool's historic data where hourly values for different years and price areas were accessible (Nord Pool, 2020). The decision regarding which data that was deemed suitable for the simulations were partly based on yearly wind data gathered from SMHI. As will be explained further in methodology, section 5.1.1, wind data for 2017 was chosen for the simulations and therefore electricity price data was also used for the same year. Electricity data for the years 2016-2020 was also gathered to see how the data from 2017 differed in comparison to adjacent years. Electricity price data from Denmark was also gathered from Nord Pool´s historic data to investigate the effect of potentially higher future fluctuations in Sweden. The electricity price data in Sweden was selected for the electricity price areas SE2 and SE3 due to the locations of the independent refueling stations and Gävle Hamn. Denmark has two electricity price areas, DK1 and DK2. The data indicated that historic prices have been approximately the same in the two areas and therefore only one electricity price area was considered to be sufficient and DK1 was chosen. A compilation of the mean electricity prices in the selected price areas in Sweden and Denmark from 2016-2020 are shown in Figure 23. It shows that the mean electricity price in the year 2017 was lower than the years 2018 and 2019 but higher than 2016 and 2020. The prices vary a lot within a year, but this gives an indication of the average price level for the specific years.

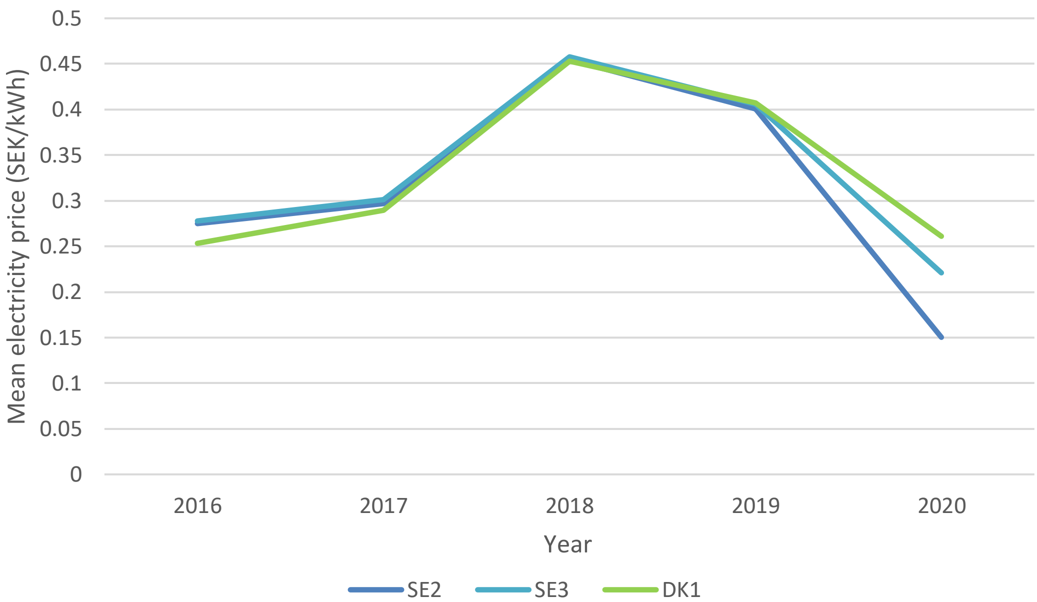

Figure 23. Mean electricity prices for electricity price areas DK1, SE2 and SE3 for the years 2016 to 2020.

Wind speed data at the locations was gathered from the Swedish Meteorological and Hydrological Institutes (SMHI) open data (SMHI, 2020). The weather station Eggegrund A was selected due to its geographical location near the planned offshore wind farm sites.

The Swedish national wind database, Vindbrukskollen, measures wind speeds at different locations and altitudes in Sweden. The highest altitudes for wind data available at Vindbrukskollen was 140 m, which is about the same height as the center of the rotor blades for the IEA 15 MW reference wind turbines (Breadmose, 2020). According to data acquired from Vindbrukskollen (2011), the average wind speed at an altitude of 140 meters in the projected area of Utposten 1 was 8.5 metre per second (m/s), Utposten 2 was 8.7 m/s and Gretas Klackar 2 was 8.8 m/s.

4.2 Hydrogen Production Component Costs

To obtain current prices of large-scale electrolyzers and storage vessels, Dave Wolff who is Region Manager of Eastern US and Canada at Nel Hydrogen, was contacted. Nel Hydrogen is one of the leading manufacturers of AEL and PEM electrolyzers today. Prices for different large-scale containerized PEM electrolyzers were accessed through Wolff and can be viewed in Table 5. According to Wolff, these numbers are conservative and likely to go down as equipment volume increases and designs continue to evolve. The prices of AEL equipment is about 20 percent less than PEM equipment. Installation, commission and training of AEL equipment on a prepared site add 30 percent of investment costs. This is due to AEL being field-erected while PEM is containerized (Wolff, 2020).

Table 5. Characteristics of Nel Hydrogen MC series PEM electrolyzers and indicative prices (Wolff, 2020).

	PEM2000	PEM3000	PEM4000	PEM5000
Net production rate [Nm^3/h]	2000	3000	4000	5000
Production capacity dynamic range [%]	10-100	10-100	10-100	10-100
Average power consumption at stack [kWh/Nm^3]	4.5	4.5	4.5	4.5
H_2 purity [%]	99.9998	99.9998	99.9998	99.9998
Operating temperature [°C]	-20-40	-20-40	-20-40	-20-40
Delivery pressure [bar]	30	30	30	30
Equipment prices [$]	10 M	13.2 M	16.6 M	20 M
Estimated additional costs for installation, commission & training	20% of equipment cost	20% of equipment cost	20% of equipment cost	20% of equipment cost
Equipment prices AEL equivalent	20% less than PEM equipment cost	20% less than PEM equipment cost	20% less than PEM equipment cost	20% less than PEM equipment cost
Estimated additional costs for installation, commission & training AEL equipment	30% of equipment cost	30% of equipment cost	30% of equipment cost	30% of equipment cost

Regarding the costs for storage vessels, Dave Wolff referred to Eddy Nupoort who is Director of Sales and Business Development at Nel Hydrogen. According to Nupoort, the indicative price of 520kg storage size which enables up to 400 kg per day dispensed is $400,000 for long vessels (up to 40 feet) and up to $660,000 for short vessels (14.7 feet). The vessels are type 1 steel. Storage can be downsized if desired and station capacity can be extended by adding storage in a later time if desired (Nupoort, 2020).

In order to estimate the costs of repurposing existing storage units or constructing a new LRC, several assumptions and calculations had to be made. This will be explained in methodology, section 5.1.4.

4.3 Operations in Gävle Hamn

In order to acquire information about the operations in the port, Linda Astner who is Sustainability Manager at Gävle Hamn, was contacted. Astner arranged a meeting with several representatives from Gävle Hamn and Henrik Rosengren, Environmental Engineer at Gävle Hamn, provided transport data and specific data for the machinery in the port.

According to data given by the haulage contractors operating in Gävle Hamn there are an average of 202 specific trucks operating in the port each day and 80 percent fewer operate during weekends. According to the same data, the average truck consumes 230 liters of diesel per day (Rosengren, 2020). The majority of the machinery operations in the port are run by the company Yilport but the company Sören Thyr AB also has some activities in one of the terminals in the port. A compilation of the machinery of Yilport and Sören Thyr AB can be seen in Table 6.

Table 6. Specific data for the machineries in Gävle Hamn operated by Yilport and Sören Thyr.

Company	Machinery	Quantity	Lift capacity [tons]
Yilport	Forklifts	43	2-33 (average 9.52)
Yilport	Wheel loaders	14	2-22 (average 9.75)
Yilport	Reachstackers	14	45
Yilport	Terminal tractors	11	32
Sören Thyr AB	Forklifts	10	unknown
Sören Thyr AB	Wheel loaders	4	unknown
Sören Thyr AB	Terminal tractors	7	unknown
Sören Thyr AB	Reachstackers	4	unknown

5. Methodology

This chapter will present the methodology used for the study. The first section will explain how the data and information from the literature review were selected, recalculated, and pre-processed to create useful data for the simulations. The next section will describe how the data was used in the simulations that were implemented in MATLAB and then compiled in Excel. Lastly, a motivation and description of the sensitivity analysis conducted in order to increase the validity of this project will be explained.

5.1 Pre-processing and transformation of data

This section will go through the adjustments, recalculations and transformation of data required for the simulations of the systems. The first section will explain how the wind data was adjusted. The second section describes the calculations to find a hydrogen equivalent to the diesel fueled machineries in Gävle Hamn. To estimate the daily hydrogen demand for the operations in Gävle Hamn, the current fuel consumption of the machinery and trucks had to be estimated.

5.1.1 Wind energy

The data over hourly wind speeds at Eggegrund A retrieved from SMHI had several data points missing for all years. To increase the validity of the study, a year with a few missing data points was needed. For this reason, the year of 2017 was chosen where 38 data points out of 8760 were missing representing 38 hours throughout the year. These points were mostly spread out over the year and were filled out through interpolation where missing data points were determined by calculating the mean of previous and following data points. In cases where more than one sequential data point was missing, the data was filled out based on an assumption of linearity between the nearest known data points through Equation 11,

$$V_i = \frac{V_{i-1}+V_{i+1}}{2} \tag{11}$$

, where V_i is the missing data point, V_{i-1} the previous data point and V_{i+1} the following data point.

The average value of the wind speed gathered from Vindbrukskollen at the locations of the projected wind farms was calculated through Equation 12,

$$V_{mean,VBK} = \frac{V_{1,mean,VBK}+V_{2,mean,VBK}+V_{3,mean,VBK}}{3} \tag{12}$$

, where $V_{1,mean,VBK}$, $V_{2,mean,VBK}$ and $V_{3,mean,VBK}$ are the average wind speeds at the planned locations of the projected wind farms obtained through Vindbrukskollen.

This gave a mean of 8.67 m/s at the altitude of 140 m. However, the data gathered at Vindbrukskollen was from 2011 and applying this to the data obtained through SMHI from 2017 could give a misleading scaling factor since wind data differ from year to year. Therefore, a comparison between different wind speeds for the years 2010-2019, gathered from SMHI (2020), was made and can be seen in Table 7.

Table 7. Average wind speeds at Eggegrund A, 2010-2019.

Year	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Wind speed [m/s]	5.61	5.61	5.66	5.75	5.47	5.75	5.55	5.87	5.33	5.68

To obtain a more accurate scaling-factor for the increase of wind speed at higher altitudes, the scaling factor was based on the relation between the average wind speed from Vindbrukskollen and the mean value of the SMHI wind data for 2011 through Equation 13,

$$C = \frac{V_{mean,VBK}}{V_{SMHI,mean,2011}} \tag{13}$$

, where C is the scaling-factor, $V_{mean,VBK}$ is the average wind speed at the three locations obtained through Vindbrukskollen and $V_{SMHI,mean}$ is the average windspeed 2011 gathered from SMHI. Further a new average wind speed at 140 meters was based on the average wind speed for the period 2010-2019 using Equation 14,

$$V_{mean} = C * V_{SMHI,mean,2010-2019} \tag{14}$$

, where $V_{SMHI,mean,2010-2019}$ is the average wind speed for the period 2010-2019 multiplied by the scaling-factor C giving a new adjusted average wind speed at 140 meters, V_{mean}. The wind data for 2017 was then scaled up to match the average wind speed using Equation 15,

$$V_{SMHI,adjusted,2017} = \frac{V_{mean}}{V_{SMI,mean,2017}} \cdot \bar{V}_{SMHI,2017} \tag{15}$$

, where $V_{SMHI,2017}$ is the vector containing hourly wind speed values for 2017, V_{mean} the adjusted average wind speed for the three sites of establishment and $V_{SMHI,mean,2017}$ is the average value of the wind speed vector for 2017. This resulted in a new scaling factor of 1.483 m/s which was used for the simulations, which means that the wind speed at an altitude of 140m is almost 50 percent higher than at ground level.

5.1.2 Operations in Gävle Hamn

In order to estimate the daily hydrogen demand for the operations in Gävle Hamn, the current fuel consumption of the machinery and trucks had to be estimated. The data over trucks operating in Gävle Hamn showed that up to around 200 trucks trafficked the port each weekday with 80 percent less operating during the weekends. This entails that 40 trucks are assumed to be operating the port daily on weekends. To estimate the hydrogen demand if all these trucks were fueled by hydrogen, the daily average consumption of diesel and efficiency of the engine has to be considered. Equation 16 was used for calculating the equivalent hydrogen consumption based on the diesel consumption.

$$C_{H2} = \frac{C_{Diesel} + E_{D,Diesel} + \eta_{Diesel\ engine}}{\eta_{Fuel\ cell} + E_{D,H2}} \tag{16}$$

C_{H2} is the hydrogen consumption in kg per h, C_{diesel} is the diesel consumption in l/h, $E_{D,diesel}$ is the energy density of the diesel in kWh per liter, $E_{D,H2}$ is the energy density of the hydrogen in kWh per kg, $\eta_{Fuel\ cell}$ is the efficiency for the fuel cell and $\eta_{Diesel\ engine}$ is the efficiency for the diesel engine. The fuel cells are assumed to operate with an efficiency of up to 60 percent (U.S. department of energy, 2015). According to the Swedish petroleum and biofuel institute, diesel has an energy density of around 9.8 kWh per liter (Svenska Petroleum & Biodrivmedel Institutet, 2020). The energy density of hydrogen is 33.33 kWh/kg (Idealhy, 2020). A modern truck engine typically has an efficiency of around 40 to 45 percent (Edgren, 2020). In the calculations the efficiency was assumed to be 45 percent, considering that the efficiency is likely to be enhanced rather than degraded in the future. Inserting these values in Equation 16 gives an average hydrogen demand per truck of 50.72 kg per day. The assumptions regarding the trucks can be seen in Appendix, Table A.

To estimate the daily hydrogen demand for the machinery in Gävle Hamn, some assumptions had to be made regarding the current energy use. For the calculations, the whole machinery was assumed to be diesel-fueled. In reality HVO[7] is also used to some extent and some of the smaller forklifts are powered electrically. The specific data over the composition of manufacturers and the size of the different machines is unknown. Since 35 percent of Yilports machinery is from the manufacturer Kalmar, fuel consumption for the forklifts with a lift capacity exceeding 5 tons and for the reach stackers was based on their product catalogue. (Kalmar, 2016, 2017, 2019a & 2019b) Consumption data for the forklifts with a lift capacity of below 5 tons was based on forklifts from the manufacturer Linde that account for 13 percent of the machinery of Yilport (Rosengren, 2020). The composition of different sizes for the Yilport machinery was based on data collected from Gävle Hamn. Data regarding the composition of different sizes for the machines run by Sören Thyr AB was unavailable and therefore assumed to be the same as Yilport. As for the trucks, Equation 16 was used for calculating the hydrogen consumption based on the diesel consumption for the machines. Regarding the engine efficiency, the diesel fueled Kalmar machines use Volvo manufactured diesel engines (Green Port, 2017). According to Staffan Lundgren at Volvo Group, diesel engines have reached an efficiency of about 50 percent. This value was chosen for calculating the hydrogen fuel consumption for all machinery (Volvo Construction Equipment, 2018). Due to lack of data from Sören Thyr AB, the composition of the 10 forklifts operated by them are assumed to be distributed similar to the forklifts of Yilport. The specific data results from the calculations are listed in Appendix, Table B.

Regarding the reachstackers, the fuel consumption was based on performance data from the manufacturer Kalmar. It was presented in ranges where the mean value was used in Equation 16 for calculating the corresponding hydrogen consumption (Kalmar, 2019a). The four reachstackers operated by Sören Thyr AB were assumed to be equivalent to the ones operated by Yilport. Information regarding the calculations can be seen in Appendix, Table C.

According to Frank et al. (2011), the fuel consumption of wheel loaders strongly depend on the operating behavior of the driver. The fuel consumption of the different wheel loaders that Yilport operate in Gävle Hamn was not presented in the performance data sheets. Assumptions about the fuel consumption were therefore based on hourly fuel consumption data presented in the Caterpillar Performance Handbook (Wheeler Cat, 2018). Wheel loaders from Caterpillar with corresponding operating weight as the wheel loaders operating in Gävle Hamn were used as reference. In the Caterpillar Performance Handbook, the fuel consumption of each model was presented as three different ranges depending on the expected workload, and the wheel loaders at Gävle Hamn were assumed to work at medium load. Further, the mean value of the consumption range for each model

[7] HVO (Hydrogenated Vegetable Oil) is a renewable fuel that can be used instead of diesel in diesel engines (Preem, n.d.).

was used in Equation 16 to calculate the corresponding hydrogen consumption. Regarding the four-wheel loaders operated by Sören Thyr AB, assumptions were made about the operating weight and the hydrogen consumption was calculated using the same methodology as for the wheel loaders operated by Yilport. The assumed fuel consumption can be seen in Appendix, Table D.

No data for the terminal tractor fuel consumption was available for the specific models operating in Gävle Hamn. Data of fuel consumption was therefore based on previous research. In the EU funded report *Studies for the LNG bunkering station for road transport and maritime transport in Luka Koper* by Gainnprojects (n.d.), the average fuel consumption of the terminal tractors in the industrial port of Luka Koper was estimated to 4.55 liters/hour. The same fuel consumption was used to calculate the corresponding hydrogen consumption through Equation 16. The assumed fuel consumption can be seen in Appendix, Table E.

The assumption about the active work hours for the machinery was based on the total annual diesel consumption of the operations in the port and the assumed hourly diesel consumption of the diesel fueled machinery using Equation 17,

$$t = \frac{C_{total,annual}}{C_{hourly}} \tag{17}$$

, where t is the active work hours, $C_{total,annual}$ is the total annual diesel consumption and C_{hourly} is the assumed hourly diesel consumption. Data for the number of heavy-duty vehicles passing in and out of the port showed that 90 percent of the activity took place on weekdays. The same relation between weekdays and weekends was assumed for the activities of the machinery (Gävle Hamn, 2020). It was also assumed to be 250 weekdays and 115 weekend days in a year (CodePlex, 2020).

In the simulations, different demand cases were evaluated since the hydrogen transition is likely to happen in stages. The cases investigated were chosen to be 15, 50, and 100 percent hydrogen transition of the operations in the port. The different demand stages and corresponding compositions of vehicles can be viewed in Table F in Appendix. The amount of hydrogen required for the different demand cases can be seen in Table 9.

Table 9. Average daily hydrogen demand for different stages of transition 15-100 percent for all machineries and trucks in Gävle Hamn.

Stages of hydrogen transition	Demand [kg/day]
15 percent	1309.23
50 percent	4364.11
100 percent	8728.22

5.1.3 Refueling Stations Traffic

For the refueling stations in Södertälje and Sundsvall, assumptions were made of an average ratio of hydrogen-fueled vehicles passing by which formed the basis for assumptions regarding the demand for hydrogen. According to the Energy Transition Outlook 2019 report, 5-13 percent of all heavy-duty vehicles are anticipated to be powered by hydrogen fuel cells by 2050 (DNV GL, 2019). Based on this, three different demand scenarios of 5, 10, and 15 percent were chosen to be investigated. Further, it was assumed that only 25 percent of the heavy-duty vehicles passing would stop at the refueling station. This was based on the assumption that not all vehicles passing by would need to refuel, and that in a future scenario it is likely that there will be more competing refueling stations in Sweden. The estimation of 25 percent market share was based on data regarding the current market shares of the gas and diesel refueling sector in Sweden, where the four biggest actors have shares of between 13-36 percent (Ganslandt & Rönnholm, 2014).

As in the Gävle Hamn case, the trucks were assumed to consume 50.72 kg per day which also was the assumed refueling demand for all trucks that stop at the station for refueling. The hydrogen consumption was calculated through Equation 16. Based on the data over the traffic flow of heavy-duty vehicles trafficking the motorways passing the refueling stations, the average daily number of trucks was set to 1270 in Sundsvall and 3990 in Södertälje. The average daily hydrogen demand for the different demand cases in both Sundsvall and Södertälje can be seen in Table 10.

Table 10. Average daily number of trucks refueling at the independent refueling stations.

Location	Demand case 5 %	Demand case 10 %	Demand case 15 %
Sundsvall	16	32	48
Södertälje	50	100	150

5.1.4 Storage

In order to dimension the size and pressures for the different storage options, the average daily demand for the two studied cases had to be reviewed. For both the case in Gävle Hamn and for the refueling stations the daily demand varied depending on the level of hydrogen transition. Therefore, the optimal storage size for constructing new LRC and using vessels above ground differs from case to case.

For the Gävle Hamn case, three different storage options were examined – repurposing the existing underground unit, constructing a new LRC storage and using vessels above ground. A maximum pressure in the existing underground storage had to be calculated to estimate the amount of hydrogen it would be capable of storing. According to Mikael Norlander, Head of R&D Portfolio and Industry Decarbonization at Vattenfall (2020), one disadvantage of repurposing the existing unit is that the shallow depth in combination with the shape of the units where the relatively large area of the ceiling facing upwards, results in a lower pressure capacity (Norlander, 2020). In general, the rock mass above the cavern generates a load determined by the volume and the density of the rock. If the pressure from the gas exceeds the load from the rock, latent cracks can open letting the gas seep out. The pressure capacity however also depends on other factors such as tectonic forces, zones of weakness, and existing cracks. To build a storage, several measurements of the rock stress as well as a meticulous mapping of the rock formations would be necessary. (Maersk Hansen, 2020). Equation 18 can be used to get a rough estimation of the pressure capacity of a cavern (Moebs et.al., 2016).

$$P = \frac{F}{A} \tag{18}$$

F represents the force in Newton (N), and A is the area (m^2). Measuring the pressure (P) at one square meter gives P=F. The force can then be determined by using Equation 19,

$$F = \rho \cdot V \cdot g \tag{19}$$

, where ρ is the density of the rock (kg/m^3), V the rock volume (m^3) and g is the standard gravity (m/s^2). The depth of the cavern at 28 meters with an area of one square meter results in a volume of 28 m^3. According to the tool *Geokartan* by the Geological Survey of Sweden (SGU), the rock in Gävle Hamn consists of sandstone, (SGU, 2020) which has a density of 2800 kg per m^3 (ThoughtCo, 2020). The standard gravity was assumed to be 9.82 m/s^2 (Nordling & Österman, 2006). Inserting the values in Equation 19 gives a maximum pressure of 76 988 pascal which equals 7.7 bars. To create some safety margins, 6 bars were used as maximum pressure for the repurposed existing underground storage in Gävle Hamn.

To decide an optimal storage size for new LRC and vessels, several different sizes were evaluated. The LCOH for the different cases depending on the dimension of the storage is illustrated in Figure 24. The plots represent a PEM system in Gävle Hamn with wind and the grid as electricity sources for the different wind electricity price thresholds of 0.2-0.6 SEK per kWh and wind farm sizes 50, 250, 400 and 600 MW. To accommodate for unexpected downtime of the system, a minimum level of hydrogen tolerated in the storage was set to equal the average daily demand.

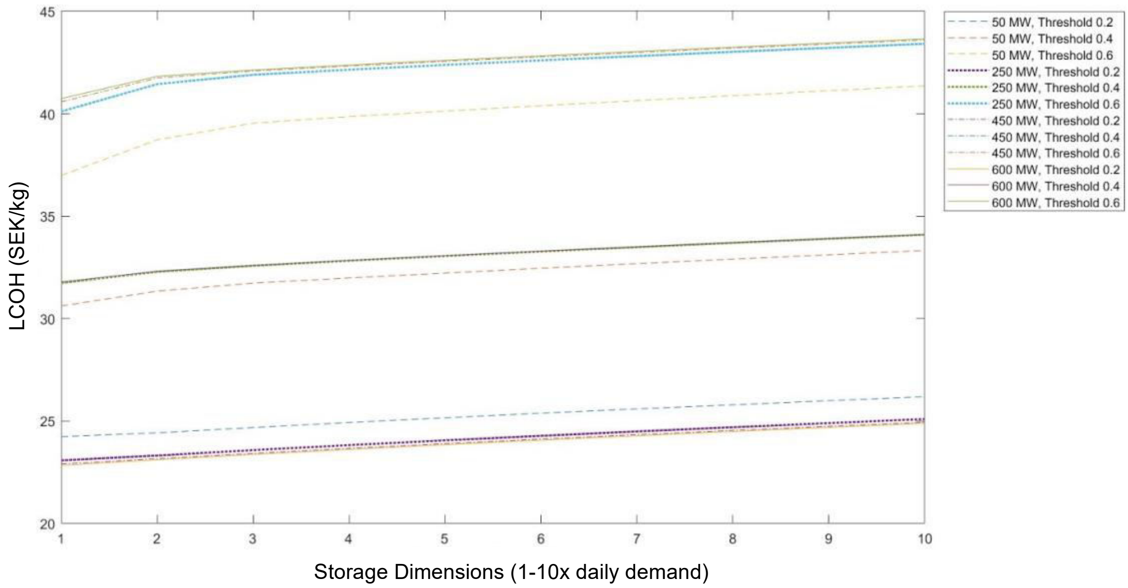

Figure 24. LCOH for different production cases based on storage dimension.

Using a storage size equal to the daily demand, compared to using larger storage sizes, resulted in the lowest LCOH for the production cases where electricity was supplied both from wind power and the electricity grid. However, a storage size that can only hold the daily demand means that if maintenance of the system was needed that would require more than one day of down time, there would be no buffer in the storage to supply the demand beyond that day. With a minimum tolerated level of hydrogen in the storage equal to the average daily demand, the electrolyzer would need to operate at maximum capacity during most hours of the year. This also limits the possibility to adjust the production rate based on the electricity price and wind electricity production. Therefore, a larger storage size was considered necessary. Since the LCOH increases with the storage size, an overdimenzioned storage would not be financially justifiable. Different storage simulations were performed to find a storage size that would include a buffer in case of operational errors in the system or if there would be a need for maintenance. A buffer corresponding to three days the daily demand was considered the optimal storage size for the simulated cases. This was motivated by the increase of the LCOH converging towards a linear relationship for storage sizes of three times the daily demand and higher, as can be seen in Figure 24. Beyond three times the daily demand there was enough room in the storage for the PEM electrolyzer to work as intended, since the increase in LCOH was constant beyond that point. One could motivate that a larger storage would result in a larger hydrogen production and possibly a higher profit since the buffer of hydrogen could be sold to other actors. However, due to the uncertainty of how large the hydrogen demand will be in the future, three times the daily demand was considered reasonable since this resulted in lower investment costs and a buffer of hydrogen that could either be sold or used for flexibility in the system.

For the case when electricity to the system is only supplied by wind power, the storage size needed was directly dependent on the installed capacity of the wind power plants. With a lower installed capacity, a larger storage buffer was needed to be able to meet the supply during periods with less wind. Therefore, different sizes of the storage was simulated in the case with only electricity from wind as a power source to determine which storage size was needed for each demand case and installed wind capacity case.

The average daily demand in Gävle Hamn was 8728.2 kg which corresponds to 97 088 Nm^3 at atmospheric pressure (1 bar). The pressure in the new LRC storage unit was set to 30 bars. 30 bars correspond to the output pressure of the electrolyzers and having the same pressure in the storage means that there was no need for an external compressor before the storage which cuts expenses. Storing 97 088.1 Nm^3 of hydrogen at 30 bar corresponds to a volume of 3 236 m^3. This means that a storage of approximately 10 000 m^3 was required to include a three-day buffer.

The maximum amount of hydrogen that could be stored in the repurposed storage unit at 6 bars was calculated to be 160 percent of the daily demand in Gävle Hamn with a three-day buffer. Based on this finding, a new demand case of 160 percent was introduced to the project, with the purpose to investigate what the LCOH stored in that case would be compared to the other storage alternatives. The average daily demand for the demand case 160 percent was calculated to be 13965 kg per day. The excess hydrogen could in a real scenario e.g. be distributed and sold to other actors.

In order to optimize the new LRC for the different demand cases of 15, 50, 100, and 160 percent, an optimal shape of the storage was needed to be found as well as a size that corresponded to three times the daily demand of the different cases. The Skallen design was used as a reference for the dimensions of the LRC caverns based on the assumption that this was an optimal shape for storing high pressures of gas. The volume was determined based on the average daily demand, according to Equation 20,

$$V = \frac{3 \cdot \left(\frac{m_{add}}{\rho}\right)}{p} \tag{20}$$

, where ρ is the density of 0.0899 (kg/m^3), m_{add} is the average daily demand (kg) and p is the pressure (bar). Since the geometrical shape of the storage is assumed to be that of a cylinder with two half-spheres at top and bottom the volume is calculated through Equation 21,

$$V = \pi \cdot r^2 \cdot h + \frac{4 \cdot \pi \cdot r^2}{3} \tag{21}$$

, where r is the radius (m) of the sphere and cylinder, and h is the height of the cylinder (m). Since the cavern needs to be lined with steel, the inner surface area of the cavern is significant to the final cost. The inner surface area was calculated using Equation 22,

$$A = 4 \cdot \pi \cdot r^2 + 2 \cdot \pi \cdot r \tag{22}$$

, where A is the area of the surface. A script was then created in MATLAB to minimize the area for each fixed volume under the constraint that the ratio between the radius and the total height of the storage would be the same as for the Skallen storage model. This constraint was formulated as Equation 23,

$$\frac{r}{H} \leq 0.35 \tag{23}$$

, where H is the total height of the storage (m) given by Equation 24.

$$H = h + 2 \cdot r \tag{24}$$

Information regarding the dimensions of the new LRC storage for the different demand cases can be seen in Table 11.

Table 11. Specifics of the new LRC storages for the different demand cases.

	Demand case 15%	Demand case 50%	Demand case 100%	Demand case 160%
Daily hydrogen demand [kg]	1309.20	4364.11	8728.22	13965.15
Volume of storage [m^3]	1 456.32	4 854.40	9 708.81	15 534.09
Dimensions of storage [m]	r = 5.96 H = 17.02	r = 8.91 H = 25.4	r = 11.22 H = 32.03	r = 13.12 H = 37.47

A schematic of the new LRC in Gävle Hamn can be seen in Figure 25. The access and shaft tunnels were assumed to have a length of 1000 meters (L_t) which is the same as the ones used for the Skallen storage.

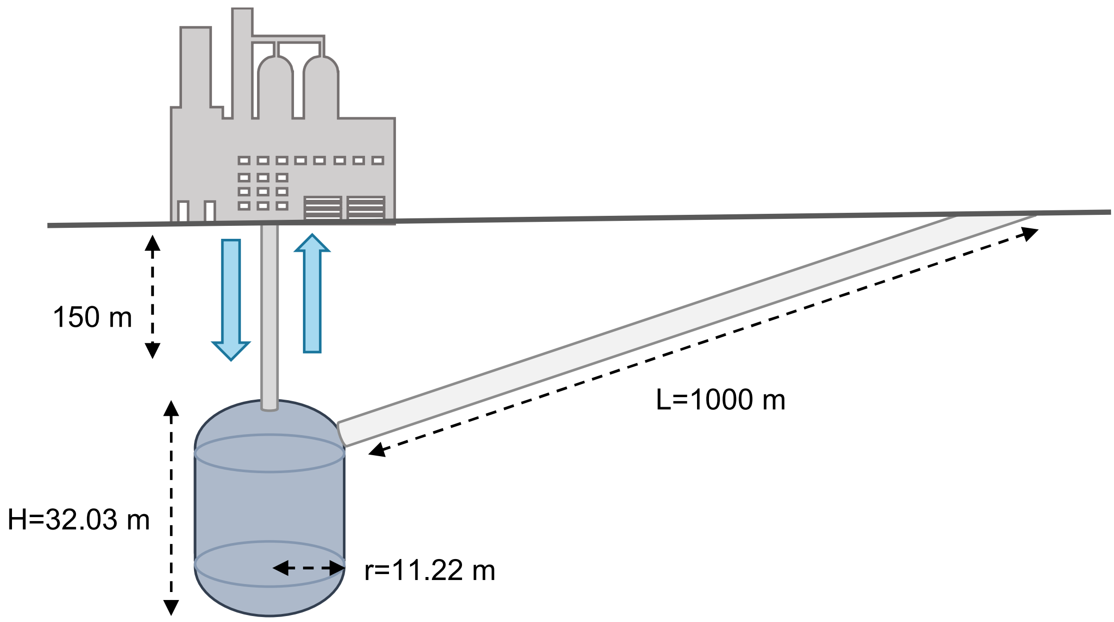

Figure 25. Illustration of the new LRC in Gävle Hamn for the demand case 100%.

Regarding the costs for repurposing the existing storage unit in Gävle Hamn, several assumptions had to be made because of the uncertainties regarding sanitation, concrete costs and lining costs in an actual project. In the pre-study *Stockholmsregionens framtida oljeförsörjning- Etapp III- Slutrapport* by Transek (2006) different alternatives regarding the future of the old petroleum storages at Loudden were evaluated. According to the study, the cost of a total sanitation of the 13 petroleum storages with a volume of 516 500 m^3 is estimated to be 20-25 million SEK (Transek, 2006). This corresponds to a cost of 48.40 SEK per m^3. In a decision basis document from Stockholms Stad (2019) regarding the repurposing of an old petroleum storage into a garage, the cost of sanitizing the storage with a volume of 90 000 m^3, is estimated to 13.7 million SEK. This corresponds to a cost of 152.20 SEK per m^3. Since the cost differs significantly between these two cases, the average cost of 100 SEK per m^3 was used in the model of this thesis, resulting in a total sanitation cost of 9 million SEK.

Assumptions regarding the thickness of the concrete lining for both the new LRC and repurposed existing storage in Gävle Hamn were based on findings in the Hybrit pre-study conducted by Johansson et al. (2018). According to the study, a concrete lining of 0.6 meters in combination with steel lining was used successfully in a LRC storage pilot project in Grängesberg. Based on this, the concrete lining in this study was assumed to be 0.6 meter. The repurposed existing storage was assumed to be cube shaped and the dimensions were approximated to be 187.5 x 15 x 32. Including a 0.6-meter-thick concrete lining the new inner dimensions are 186.3 x 13.8 x 30.8 giving a new storage volume of 79 185 m^3. The new inner surface area to be lined with stainless steel was calculated to be 17 468 m^2.

In the report *Cost optimization of the underground gas storage* by Žlender and Kravanja (2011), nonlinear programming (NLP) was used to optimize the minimal system investment cost when constructing a new LRC. The economic data from the results can be seen in Table 12. This data was used to calculate the costs of repurposing the existing storage unit as well as constructing a new LRC storage in Gävle Hamn.

Table 12. Economic data from NLP optimization of constructing a new LRC (Žlender & Kravanja, 2011)

Cost variables of constructing LRC	Costs
Upper ground works (C_{ugw}) [€]	2 982 500
Underground works (C_{uw}) [€]	2 798 025
Cost of the tunnel excavation ($C_{t,exc}$) [€/m]	2 440
Cost of the tunnel protection ($C_{tl,prot}$) [€/m]	1 340
Cost of the cavern excavation ($C_{c,exc}$) [€/m^3]	100
Cost of the cavern protection ($C_{c,prot}$) [€/m^2]	90
Cost of the cavern drainage ($C_{c,drain}$) [€/m^2]	60
Cost of the cavern wall concrete (Cconc) [€/m^3]	190
Cost of steel lining (Csteel) [€/m^2]	920

The volume needed to excavate to fit a 0.6-meter concrete lining was calculated through Equation 25.

$$V_{exc} = \pi \cdot (r + 0.6)^2 \cdot h + \frac{4 \cdot \pi \cdot (r+0.6)^2}{3} \quad (25)$$

The total volume of concrete covering the cavern walls was calculated using Equation 26.

$$V_{concrete} = V_{exc} - \left(\pi \cdot r^2 \cdot h + \frac{4 \cdot \pi \cdot r^3}{3}\right) \tag{26}$$

The inner area of the cavern was calculated through Equation 27.

$$A_c = 2 \cdot (r + 0.6) \cdot \pi \cdot h + 4 \cdot \pi \cdot (r + 0.6)^2 \tag{27}$$

The area to be covered by the steel lining was calculated using Equation 28.

$$A_s = 2 \cdot r \cdot \pi + 4 \cdot \pi \cdot r^2 \tag{28}$$

Finally, the CAPEX for the new LRC storage was calculated through Equation 29.

$$\begin{aligned} CAPEX_{LRC} = {} & L_t \cdot \left(C_{t,exc} + C_{t,prot}\right) + V_{exc} \cdot C_{c,exc} + \\ & A_c \cdot \left(C_{c,prot} + C_{c,drain}\right) + A_s \cdot C_{steel} + \\ & V_{conc} \cdot C_{concrete} + C_{ugw} + C_{uw} \end{aligned} \tag{29}$$

The variables in Equation 29 are explained in Table 12. The CAPEX for repurposing the existing storage was calculated using Equation 29 but only including the parameters of the concrete and steel lining and adding the fixed sanitation cost. Since the obtained data was from 2011, the calculated CAPEX was further modified to correspond to the present monetary value in regard to inflation which according to Statistics Sweden (SCB, n.d.) has risen by 1.08.

For storage in vessels above ground, the type 1 steel vessels with information regarding capacity and prices from Nel Hydrogen were chosen. The vessels can deliver 400 kg hydrogen per day and comparing this to the daily demand of 8741.7 kg means that approximately 22 vessels are needed to store the daily hydrogen demand. Including a buffer of three times the daily average demand means that 66 vessels are needed for the demand case 100%.

A compilation of the information regarding the storage options for the different demand cases can be seen in Table 13.

Table 13. Specifics of the different storage alternatives for the demand cases.

	Existing storage	New LRC 30 bar	Vessels 40 feet
Demand case 15%			
Volume of storage [m^3]	79 184.95	1 456.32	
Storage capacity [kg]	42 712	3927.70	4000 (10 vessels)
Storage Capex [SEK]	202.82 M	116.50 M	34.16 M
Demand case 50%			
Volume of storage [m^3]	79 184.95	4 854.40	
Storage capacity [kg]	42 712	13 092	13 200 (33 vessels)
Storage Capex [SEK]	202.82 M	131.20 M	112.73 M
Demand case 100%			
Volume of storage [m^3]	79 184.95	9 708.81	
Storage capacity [kg]	42 712	26 185	26 400 (66 vessels)
Storage Capex [SEK]	202.82 M	148.20 M	225.46 M
Demand case 160%			
Volume of storage [m^3]	79 184.95	15 534.09	
Storage capacity [kg]	42 712	41 895	42 400 (106 vessels)
Storage Capex [SEK]	202.82 M	166.18 M	362.10 M

5.1.5 Optimizing Electrolyzer Production Capacity and Cost Estimations

The data acquired from Wolff over the electrolyzer prices for Nel Hydrogen was recalculated to get the unit American dollars (USD) per kW. This was done to compare these numbers with the values obtained in the literature review from the report *Assessment of Hydrogen Production Costs from Electrolysis: United States and Europe*. Equation 30 was used to convert the data gathered from Wolff to kW, presented in Table 14.

$$kW = \frac{Nm^3}{h} \cdot \frac{kWh}{Nm^3} \tag{30}$$

Table 14. Characteristics and associated costs of Nel Hydrogen MC series electrolyzers (Wolff, 2020)

	PEM2000	PEM3000	PEM4000	PEM5000
Net production rate [Nm^3/h]	2000	3000	4000	5000
Average power consumption at stack [kWh/Nm^3]	4.50	4.50	4.50	4.50
Power consumption [MW]	9.00	13.60	18.10	22.65
CAPEX [$]	10.00 M	13.20 M	16.60 M	20.00 M
CAPEX including installation, commission & training [$]	12.00 M	15.84 M	19.92 M	24.00 M
AEL equivalent CAPEX [$]	8.00 M	10.56 M	13.28 M	16.00 M
AEL equivalent CAPEX including installation, commission & training [$]	10.40 M	13.73 M	17.26 M	20.80 M

Once the capacity (kW) was calculated for the different electrolyzers, the total cost was divided by this number to obtain the cost of power consumed. The results can be viewed in Table 15 along with the price estimations of PEM and AEL technologies acquired from the report *Assessment of Hydrogen Production Costs from Electrolysis: United States and Europe* (Christensen, 2020).

Table 15. Costs for the Nel electrolyzers (Wolff, 2020) and electrolyzers according to Christensen (2020).

	PEM2000	PEM5000	Christensen	AEL2000	AEL5000	Christensen
$/kW	1103	883	385 - 2068	909 - 1053	727 - 842	571 - 1268
SEK/kW	9525	7620	14000–21000	7845 - 9084	6276 - 7267	8000-15000

As can be seen, the electrolyzer cost per kW from Nel Hydrogen lies within or below the price ranges presented in the *Assessment of Hydrogen Production Costs from Electrolysis: United States and Europe* report. This indicates that the prices are reasonable and valid for the study. However, if a hydrogen energy system would be implemented it is likely that the electrolyzers would be dimensioned optimally to the specific purpose and hydrogen demand. Therefore, an analysis of the relation between production capacity and cost from the electrolyzer prizes obtained through Wolff was made.

In order to estimate the cost of electrolyzers below, above and in between the given electrolyzers and prices, interpolation was used and implemented in MATLAB. Further, the alkaline electrolyzers were dimensioned to have the production capacity equal to the daily demand. The PEM electrolyzers had a production capacity of around 30 percent more than the daily demand to enable flexible regulation depending on wind conditions and electricity prices. The dimensions and prices of the electrolyzers for the different demand cases can be seen in Table 16. The CAPEX was converted from USD to SEK with the current exchange rate fixed to 8.54 SEK per USD which was the exchange rate on 24th of November 2020. (DI, 2020)

Table 16. Information regarding electrolyzer prices and capacities for the different demand cases in Gävle Hamn.

	Demand case 15%	Demand case 50%	Demand case 100%	Demand case 160%
PEM				
Production capacity [Nm^3/h]	800	2700	5300	8500
Power consumption [MW]	3.6	12.2	24	38.5
CAPEX [SEK]	63.13 M	125.44 M	215.413 M	329.112 M
AEL				
Production capacity [Nm^3/h]	650	2100	4100	6500
Power consumption [MW]	2.95	9.5	18.6	29.45
CAPEX [SEK]	50.42 M	91.66 M	150.42 M	222.98 M

The same methodology was used to estimate the production capacity and prices of the electrolyzers used for the independent refueling stations in Sundsvall and Södertälje, which is presented in Tables 17-18.

Table 17. Information regarding electrolyzer prices and capacities for the different demand cases for the refueling station in Södertälje.

	Demand case 5%	Demand case 10%	Demand case 15%
PEM			
Production capacity [Nm^3/h]	1600	3100	4700
Power consumption [MW]	7.25	14	21.3
CAPEX [SEK]	89.363 M	138.758 M	194.507 M
AEL			
Production capacity [Nm^3/h]	1200	2400	3600
Power consumption [MW]	5.44	10.87	16.3
CAPEX [SEK]	66.07 M	100.19 M	135.34 M

Table 18. Information regarding electrolyzer prices and capacities for the different demand cases for the refueling station in Sundsvall.

	Demand case 5%	Demand case 10%	Demand case 15%
PEM			
Production capacity [Nm^3/h]	500	1000	1500
Power consumption [MW]	2.25	4.5	6.75
CAPEX [SEK]	53.29 M	69.69 M	89.08 M
AEL			
Production capacity [Nm^3/h]	400	800	1200
Power consumption [MW]	1.81	3.62	5.44
CAPEX [SEK]	43.32 M	54.69 M	66.07 M

5.1.6 Costs of Refueling Station Components

In order to calculate the LCOH for the different cases, the costs of the components in the utilization-stage had to be estimated. The costs of the refueling station components were based on the cost estimations in the report *Impact of hydrogen refueling configurations and market parameters on the refueling cost of hydrogen* by Reddi et al. (2017) presented in chapter 2.4.5. Based on the cost relations between the different components depending on the size of the refueling station, the pie-charts shown in Figure 26 were created.

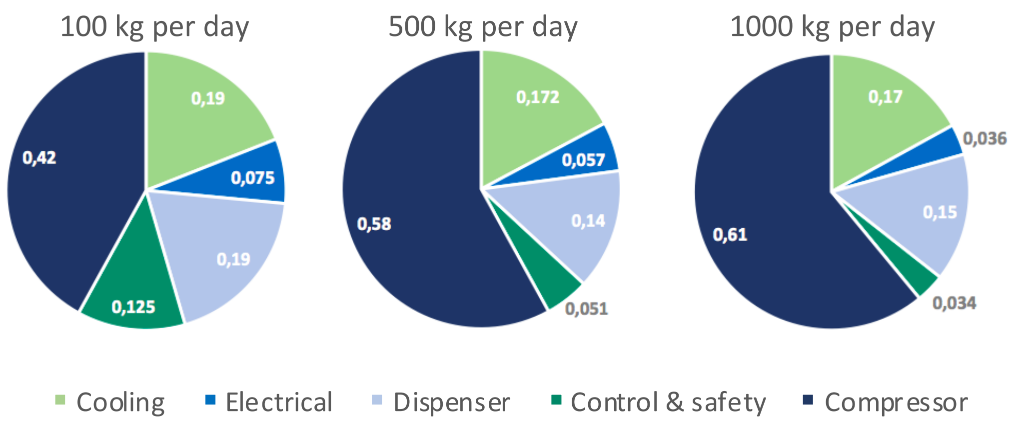

Figure 26. The impact of station utilization and economies of scale on hydrogen refueling station *levelized cost for capacities 100, 500 and 1000 kg per day.*

Regarding the cases in this study, even the smallest demand case has a higher demand than 1000 kg per day, which was the largest system simulated by Reddi et al. (2017). Due to the lack of information regarding how these relative component costs vary for large systems, the same percentual relation as for the 1000 kg per day case was assumed for all the simulated cases. This was considered a reasonable assumption since the difference between the 500 and 1000 kg cases only differed with a few percentages and the three cases indicated that the cost relations between the components converges for larger systems. The percentage share of component costs for different refueling station sizes cost changes can be seen in Figure 27.

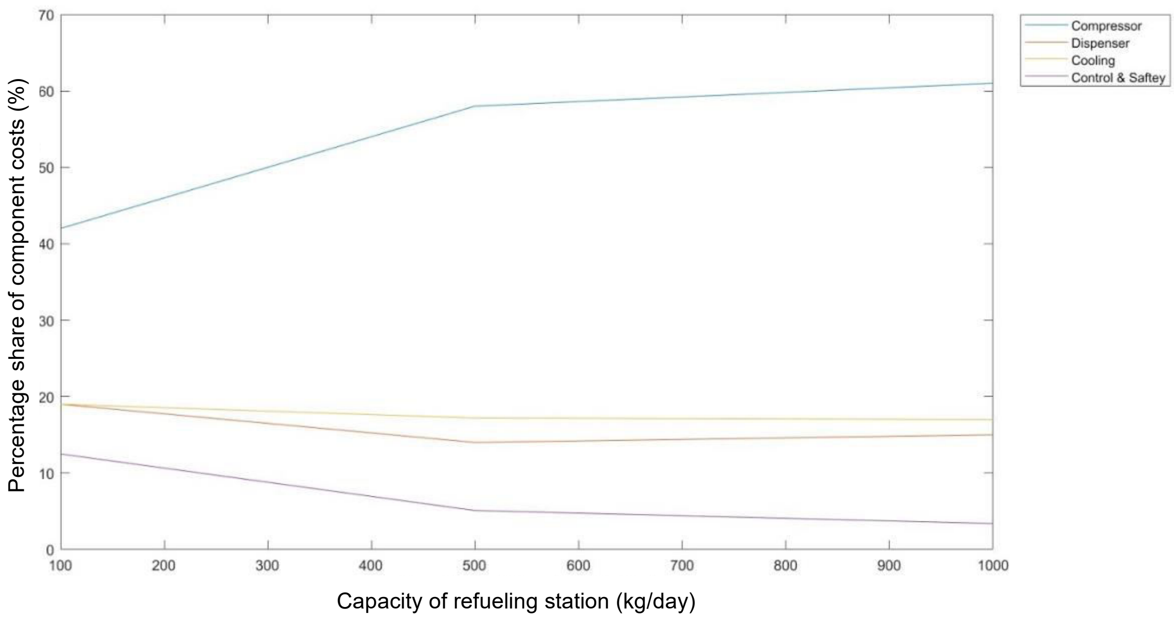

Figure 27. Graph of the percentual share of component costs for different sizes of refueling stations.

The component costs for the different simulated cases in this study differed depending on the dimensions of the compressor and the related cost. In turn, the prices for electricity, control and safety, dispenser and cooling equipment all depended on the price of the compressor. These percentual relations are presented in Table 19.

Table 19. Percentual cost relations of the different components in the distribution stage.

	Cooling	Compressor	Dispenser	Electrical	Control & Safety
CAPEX share [%]	17.00	61.00	15.00	3.60	3.40

The compressor cost for the different systems was estimated based on the price information presented in chapter 2.4.3. The cost of the compressor that best matched the compressor sizes simulated in this study corresponded to a cost of 3.32 USD per kg hydrogen.

5.2 Simulations

The simulation model that was implemented in MATLAB is described in the flow charts found in Figures 29-32. The flow charts for the two main cases, Gävle Hamn and the independent refueling stations, are divided into two parts. The first flow chart for each case shows the data generation for the different simulation cases and the second flow chart shows the simulation process over all the hours of a year. The figures are further divided into sub charts for different parts of the simulations. Figure 28 shows the different blocks used in the flow charts.

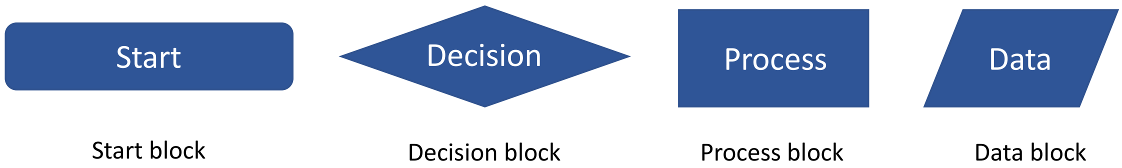

Figure 28. The different blocks used to represent the steps and functions in the MATLAB simulations.

5.2.1 Gävle Hamn Simulations

In Figure 29, a process chart is presented that illustrates the generation of specific data for each simulated case for Gävle Hamn. The processes in the subcharts depicted in Figure 29 are explained in the following sections.

Subchart 1

The size of the offshore wind farm was decided to be either 50, 250, 450 or 600 MW. Based on this, the electricity production from the wind farms was computed.

Subchart 2

The demand was decided to 15, 50, 100 or 160 percent and based on this the demand data was initiated.

Subchart 3

The storage option was decided to either use the repurposed existing storage, the new LRC storage for a pressure of 30 bars or using multiple vessels. Based on this decision, storage data and storage cost data was generated. The storage was assumed to be full at the start of the simulation.

Subchart 4

The production case was decided and based on the production case, initial production data and data over fixed component costs was generated. If an AEL system was selected for the hydrogen production, the hourly production rates in the production data were decided based on the average hourly demand. The production cost data was based on both the demand case decision, which determines the size of electrolyzer, and on the production case decision that determines whether the electrolyzer was PEM or AEL. If hydrogen production using a PEM electrolyzer was selected, and the electricity produced by the offshore wind power plants was the only electricity source, the production data was generated based on the wind electricity production for all hours of the year. If the facility was also connected to the grid, the production rate was determined based on threshold prices representing different wind electricity prices. The different price thresholds simulated were 0.2, 0.3, 0.4, 0.5 and 0.6 SEK per kWh. When the electricity price was lower than the threshold price, the electrolyzer production rate was set to maximum capacity. This means that as much wind power as possible was used to produce hydrogen because it would be less profitable to sell the wind electricity to the grid. When the electricity price was higher than the threshold price the production rate was decreased to a base production rate. Having a base production is necessary to ensure that the storage never runs empty. The base production rate was decided by simulating the system with different base production rates of 10-100 percent. The results showed that the optimal base production rates for an average wind electricity price of 0.2 SEK per kWh was 70 percent and for 0.3 SEK per kWh it was 50 percent. For wind electricity prices higher than 0.3 SEK per kWh, that is when the wind electricity price was higher than the average electricity price when buying from the grid, the lowest LCOH was achieved by having a 100 percent base production. This means that if the electricity price from the grid is lower than the wind electricity price, it is more beneficial in terms of LCOH to have a constant maximum hydrogen production at all times since a higher share of the electricity to the production then is fed from the grid. In this case, the flexibility that PEM provides is unnecessary if the aim is to achieve the lowest possible LCOH. However, since the aim of the hydrogen production system integrated with wind electricity production is to achieve the highest possible return for the whole system, the most beneficial strategy is to use as much wind electricity as possible in times with low electricity prices. But, if the base production is at 100 percent, the storage is almost always full which limits the systems potential to maximize hydrogen production when electricity prices are low, and the aim is to make use of as much wind power as possible.

When the threshold price is similar to the average electricity price for 2017, which was 0.3 SEK per kWh, the most economically beneficial option is to have a base production at 50 percent. This enables the system to switch from the grid and wind power more frequently and make better use of the storage. For this reason, the base production was set to 50 percent for all simulated cases.

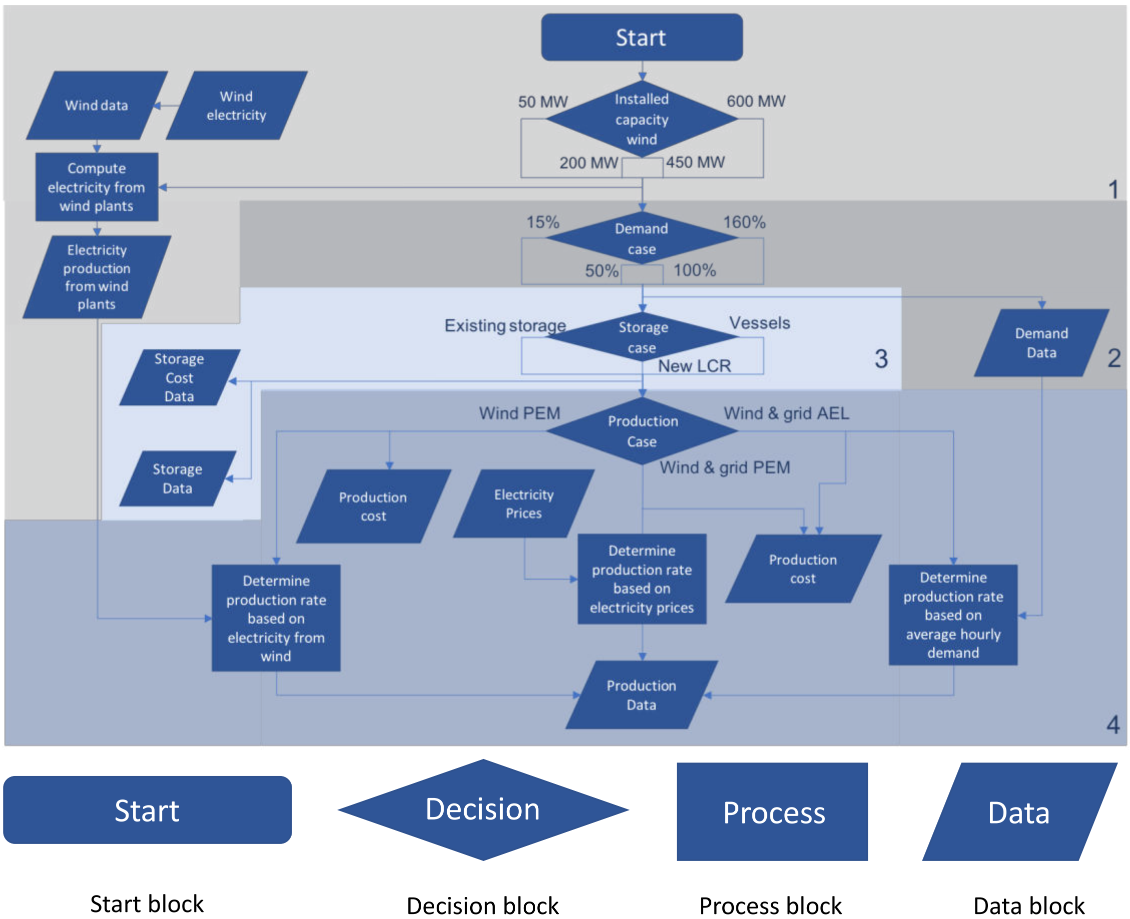

Figure 29. The process chart of generating the specific data for each simulation case for Gävle Hamn.

Figure 30 shows the next step in the simulation process which was to generate hourly values of the storage level and calculate the LCOH. The processes in the subcharts depicted in Figure 30 are explained in the following sections.

Subchart 1

The storage level was computed based on the storage level going into the specific hour, the production rate and the demand rate of the specific hour.

Subchart 2

The decision was made whether the storage level was critically high or low. The storage level was deemed critically high if it was above 95 percent of the total storage capacity, and critically low if it was below the amount of hydrogen corresponding to the average daily demand. The storage level for the simulated hour was saved in the storage level data set and the production rate for that hour was saved in the final production data set.

If the storage level was critically low the production for the following hour was set to maximum production rate, and if the storage level was critically high the production for the following hour was set to minimum production rate. However, if the production case was a PEM electrolyzer with electricity supply exclusively from wind power, the availability of electricity needed to be verified before increasing the production to the maximum. If the electricity available was not high enough to meet the electricity demand for the electrolyzer to produce at maximum rate, the adjusted production was set to the highest possible production rate instead. The adjusted production value then replaced the initial production value set for the next hour.

Subchart 3

The LCOH was computed based on the electricity cost which was retrieved from the final production data, the electricity prices from both the grid and the wind farms, the production cost data and the storage cost data.

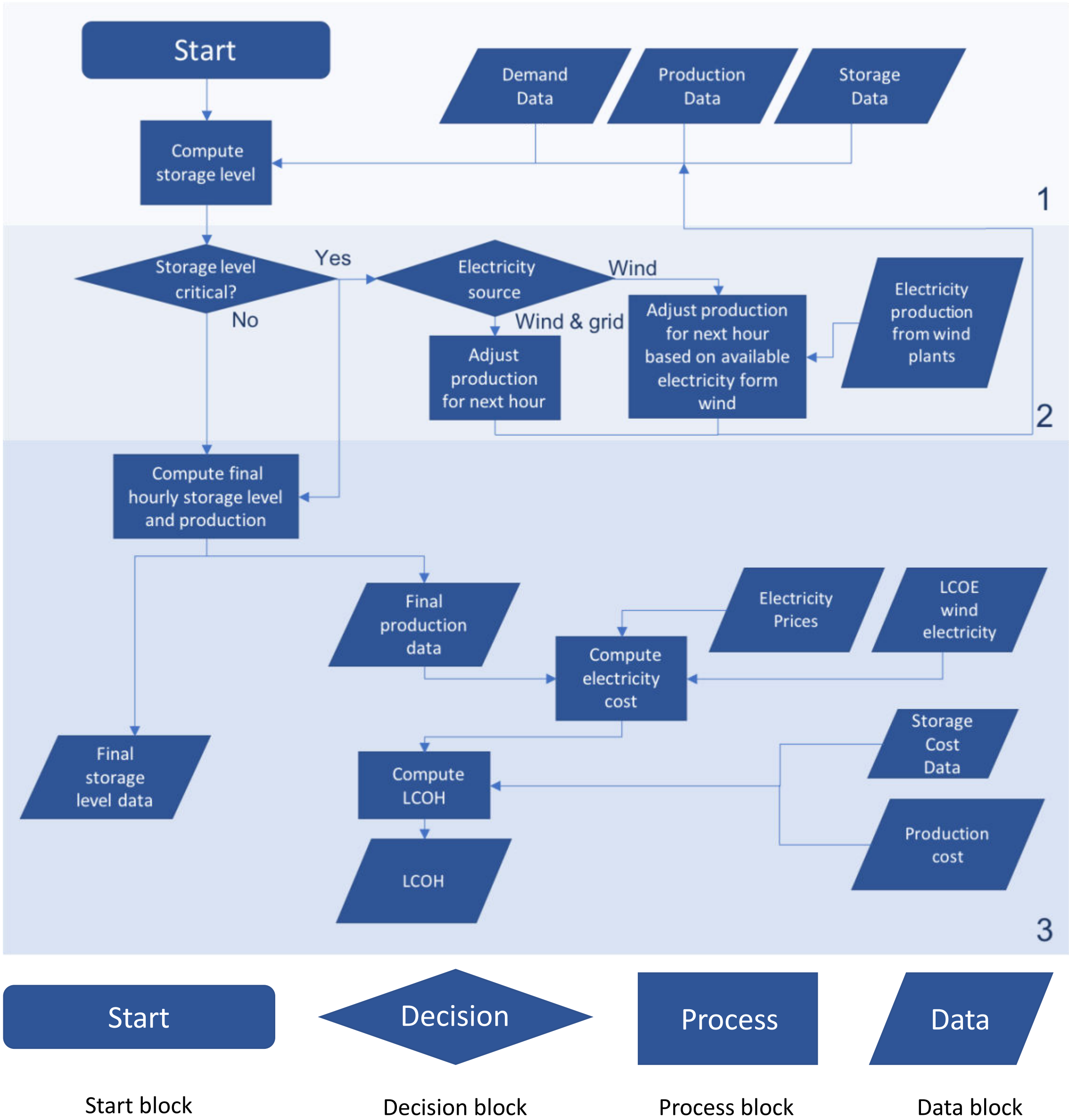

Figure 30. The simulation process Gävle Hamn where LCOH and hourly values of the storage level is generated.

5.2.2 Independent Refueling Stations Simulations

In Figure 31, a flow chart is presented that illustrates the generation of specific data for each simulated case for the independent refueling stations in Sundsvall and Södertälje. The processes in the subcharts depicted in Figure 31 are explained in the following sections.

Subchart 1

The location was decided to either Sundsvall or Södertälje. Based on this decision, the data over hourly electricity prices for a year was decided since Sundsvall and Södertälje are situated in different bidding areas.

Subchart 2

The demand case was decided to either 5, 10 or 15 percent. Based on this, demand data was generated as well as data over the storage size and cost. The demand data was generated for the different simulation cases by a randomized sampling of the number of trucks refueling each hour of the year based on the assumptions regarding the daily number of trucks refueling at each location. The storage was assumed to be full at the start of the simulation.

Subchart 3

The production case was decided to either use PEM or AEL. Based on this decision, initial production data was generated. If production through AEL was selected, the production was set to a fixed rate corresponding to the average hourly demand for all hours of the year. If production through a PEM electrolyzer was selected, the initial production data was generated depending on the electricity prices. The production rate was decided based on whether the electricity price was higher or lower than the price thresholds of 0.2, 0.25, 0.3, 0.35, and 0.4 SEK per kWh. When the electricity price was lower than the threshold price the production rate was set to maximum capacity and when the electricity price was higher than the threshold price the production rate was decreased to a base production rate. In this case, unlike the case in Gävle Hamn, electricity from the grid was the only energy source. To find the optimal base production, simulations were made with varying base productions ranging from 10-100 percent. The results showed that the lowest LCOH was achieved with a base production of 50 percent from threshold prices 0.2 and 0.25, and 10 percent for the threshold prices 0.3 and above. This shows that with threshold prices lower than the average electricity price, a higher base production is beneficial because it prevents the storage from going empty and in turn forcing the system to produce hydrogen with maximum capacity even when the prices are high. For threshold prices higher than the average electricity price, lower base production is possible without the storage going empty since there is a sufficient number of hours when the electricity price is lower than the threshold price to meet the demand. The lowest LCOH achieved was for the threshold price 0.3 SEK per kWh which corresponds to a 10 percent base production. Therefore, 10 percent was chosen as base production for all cases. As in the Gävle Hamn case, the production cost data was based on both the demand and production case decision.

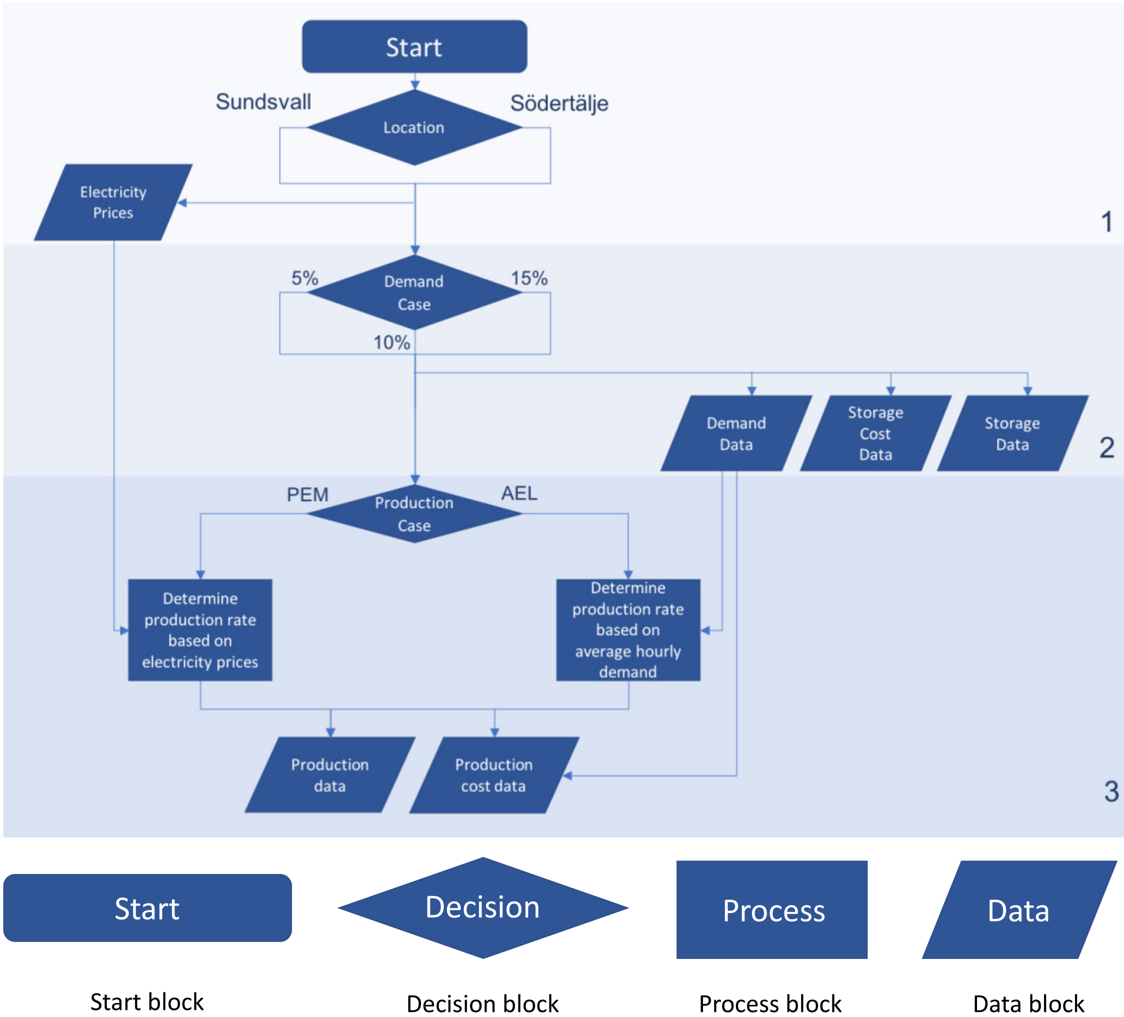

Figure 31. The process of generating the specific data for each simulation case for the independent refueling station.

Figure 32 shows the next step in the simulation process which was to generate hourly values of the storage level and calculate the LCOH for the refueling stations in Sundsvall and Södertälje. The simulation steps were similar to the ones used for the Gävle Hamn simulations. The processes in the subcharts depicted in Figure 32 are explained in the following sections.

Subchart 1

Storage data was generated based on the storage level going into the specific hour, the production rate and the demand rate of the specific hour.

Subchart 2

The storage level was reviewed where the same threshold values were used as for Gävle Hamn. The storage level for that hour was saved in the final storage level data set and the production rate for that hour was saved in the final production data set. If the storage level was critically low, the production for the next hour was set to maximum production rate and if the storage level was critically high the production for the next hour was set to minimum production rate. The adjusted production value then replaced the initial production value for the following hour.

Subchart 3

The LCOH was computed based on the electricity cost which was retrieved from the final production data and the electricity prices, the production cost data, and the storage cost data.

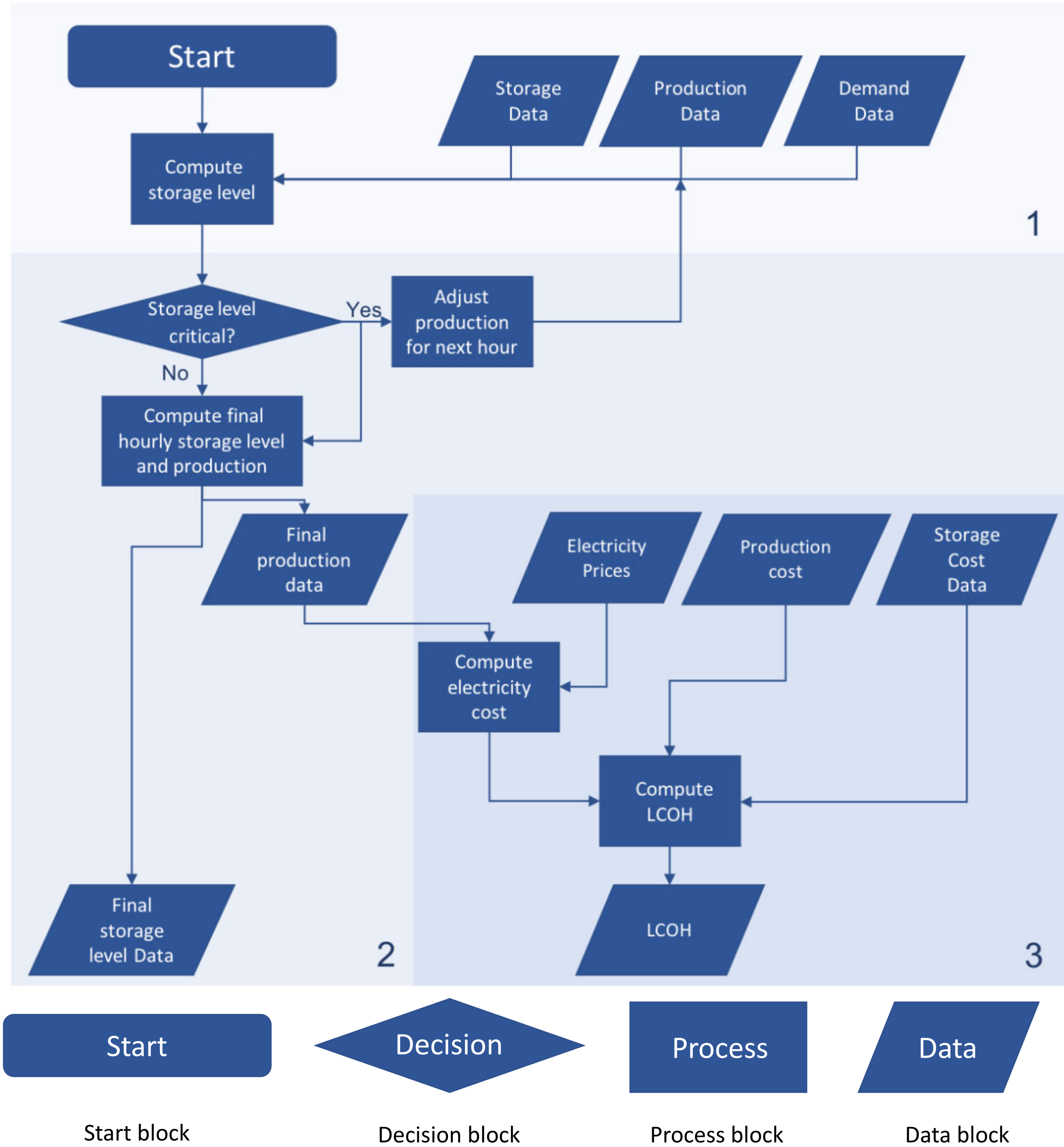

Figure 32. The simulation process for the independent refueling station where LCOH and hourly values of the storage level is generated.

5.3 Sensitivity Analysis

To increase the validity of the study, a sensitivity analysis was made. A parameter that is likely to change over time is electricity price. However, future electricity prices are difficult to predict. According to Energimarknadsinspektionen (2019) electricity prices will become more volatile as a result of a larger share of renewable energy sources (Svenska kraftnät, 2015). For this reason, electricity price data from Denmark was used as a reference to see how more fluctuating electricity prices might affect the hydrogen production and LCOH. This was done by running the same simulations as in the original cases but changing the Swedish electricity prices to Denmark's over the same time period. The electricity prices were also adjusted to match the Swedish average electricity price of 2017 to enable a comparison between the two cases. This sensitivity analysis was only made for the PEM systems since the AEL systems have a constant hydrogen production regardless of the fluctuations on the grid.

A second method introduced to simulate possible future electricity prices and the impact it would have on the results was by increasing and decreasing the electricity prices over the simulated year. This was made by comparing a 25 percent increase in electricity prices and a 25 percent decrease to the original case to evaluate the impact electricity prices might have on the final LCOH.

Due to the fact that there is a rapid development within the hydrogen industry, there are many parameters that could change before the implementation of an actual system like the ones studied in this thesis. One future prediction is a major reduction in electrolyzer costs. According to previous studies presented in section 2.3.4, the prices of electrolyzers are predicted to decrease by 20-80 percent by 2030. In order to investigate the impact such a price reduction could have on the LCOH, simulations were run with 25, 50 and 75 percent lower electrolyzer CAPEX. This was only done for the Gävle Hamn case since changing a fixed cost parameter would have the same impact trends regardless of the system.

To investigate the impact of a future scenario where PEM and AEL share the same investment costs, as implicated by previous studies, simulations were run with the same CAPEX for the AEL and the PEM electrolyzer. The simulations were made for the refueling station case in Södertälje with 15 percent demand. The refueling station case was selected due to the production strategy for this case being to produce hydrogen to the cheapest price possible. In Gävle Hamn, the strategy was to include as much wind power as possible to enable the highest possible return for the whole integrated system. Therefore, the AEL and PEM systems in Gävle Hamn are not comparable.

Another main uncertainty factor in this project was the underground storage capacity. For the repurposing of the existing underground storage, a maximum pressure of 6 bars was chosen due to 7.7 bars being assumed to be the highest pressure the storage could hold. There is however a possibility that the actual pressure capacity could be both lower and higher. A lower pressure capacity was not considered of interest to investigate since the CAPEX of the storage would be the same, only resulting in a lower storage capacity. A higher pressure was however of interest to investigate since this would result in a larger storage capacity and possibly a lower LCOH for the existing storage. A fifth demand case was therefore introduced with a new maximum pressure of 10 bars in the repurposed existing underground storage. The impact on the LCOH of having a higher pressure in the new LRC was also considered interesting to evaluate since this is the pressure used in e.g. the Skallen storage facility. Having a larger storage pressure than the output pressure of the electrolyzer involves including a second compressor to the system, since the pressure needs to be increased before the storage but also when the gas is transferred from the storage to the refueling stage which requires a higher output pressure. The aim was to investigate the impact on the LCOH of having a higher pressure in the storage resulting in a smaller storage and lower investment costs but also higher CAPEX and OPEX for the compressor. The possibility to receive federal subsidies for the project is another example of a cost changing factor that could affect the LCOH. For the construction of the LRC storage in the Hybrit project, the Swedish Energy Agency will subsidize 25 percent of the investment cost. Based on this, a 25 percent reduction of the CAPEX for the new LRC storage was evaluated.

6. Results

In this chapter, the findings from the simulations will be presented. The chapter is divided into three sections. The first section presents the results from the simulations of the HES in Gävle Hamn. The second section will present the results from the simulations for the refueling stations in Södertälje and Sundsvall. Lastly, the results from the sensitivity analysis will be presented.

6.1 Hydrogen Energy System in Gävle Hamn

This section presents the results regarding the HES in Gävle Hamn. The first part shows the results from the simulations in MATLAB, and the second part contains the LCOH results.

6.1.1 Simulations in MATLAB

The simulations in MATLAB generated different results depending on the chosen electricity source, electrolysis technology, storage options and demand case. The plots as a result of the simulations in MATLAB illustrate the hydrogen storage level, the electricity source (wind farms, the grid, or both) as well as the electricity price for all hours over the year. Since these simulations were made for each production, storage and demand case, this generated hundreds of plots. Therefore only a few plots that highlight interesting behaviors of the system will be presented in this report. In Figures 34-38, the plots from the simulations of a PEM system with electricity supply from the grid and wind farms with an installed capacity 600 MW, using a new LRC as storage with 30 bars operating pressure and demand case 100% are shown for different wind electricity prices. It can be seen that the lower the wind electricity price, the more electricity is utilized from the grid instead of the wind farms. This was due to it being more financially beneficial to sell wind electricity to the grid during periods when electricity prices were higher. This resulted in lower hydrogen levels in the storage since the system was told to operate at base production during most of the year (see Figure 38). Table 20 shows the percentage share of electricity being utilized from both the grid and the wind farms. Figure 33 shows the hourly electricity prices over the simulated year.

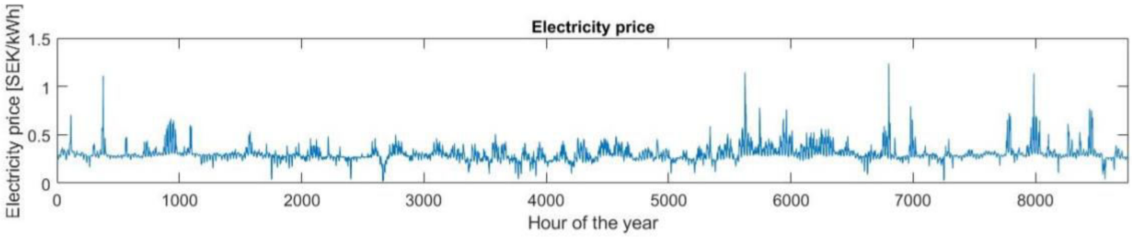

Figure 33. Hourly electricity price over the simulated year 2017.

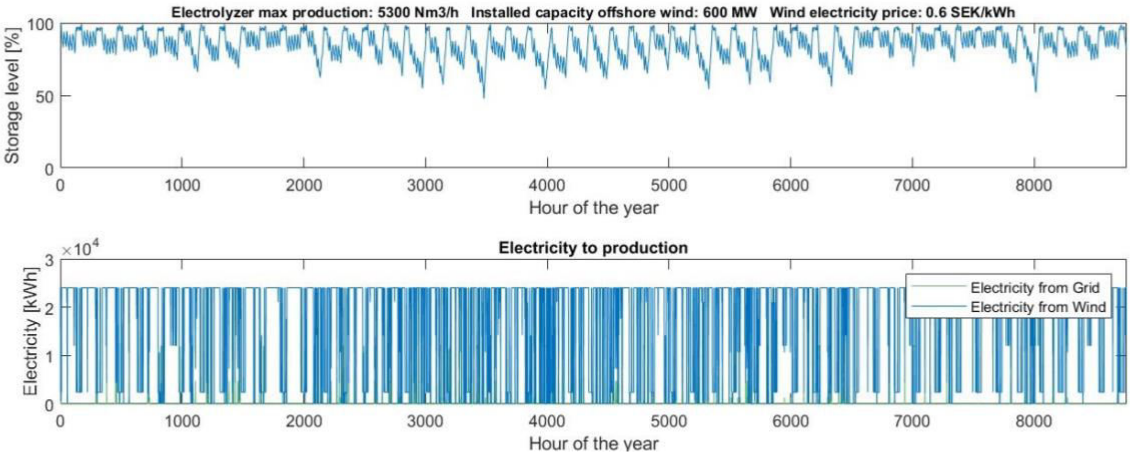

Figure 34. Plots of the simulated PEM system with electricity utilized from the grid and a 600 MW wind farm, using a new LRC storage at 30 bar operating pressure and wind electricity 0.6 SEK per kWh.

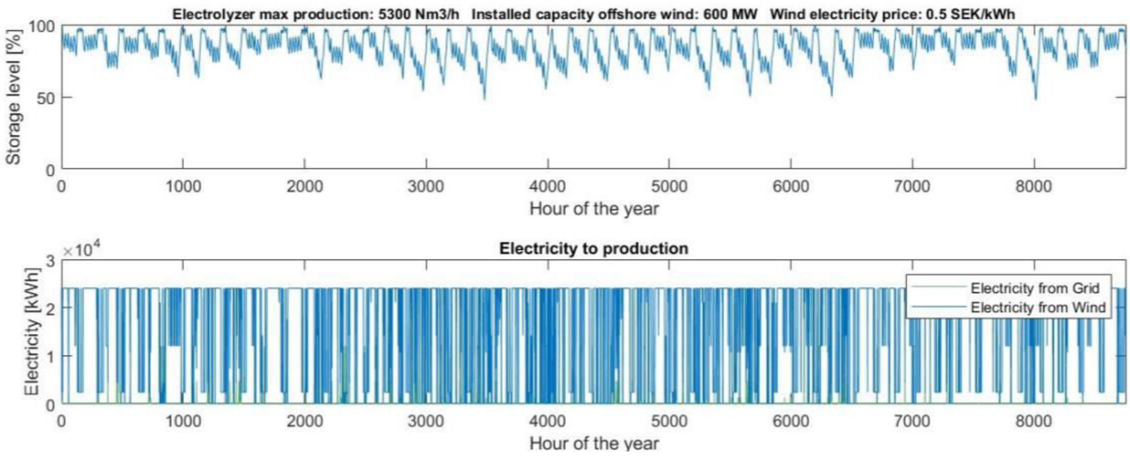

Figure 35. Plots of the simulated PEM system with electricity utilized from the grid and a 600 MW wind farm, using a new LRC storage at 30 bar operating pressure and wind electricity 0.5 SEK per kWh.

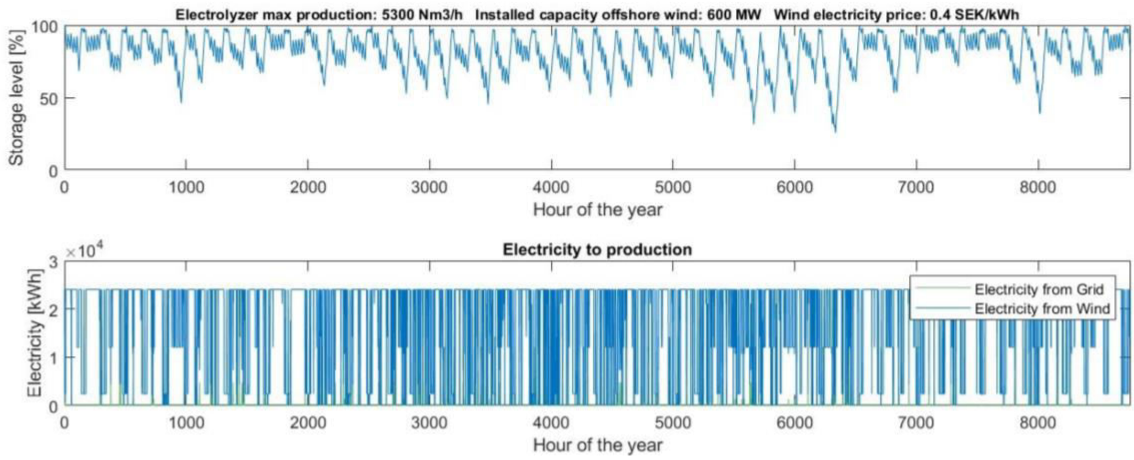

Figure 36. Plots of the simulated PEM system with electricity utilized from the grid and a 600 MW wind farm, using a new LRC storage at 30 bar operating pressure and wind electricity 0.4 SEK per kWh.

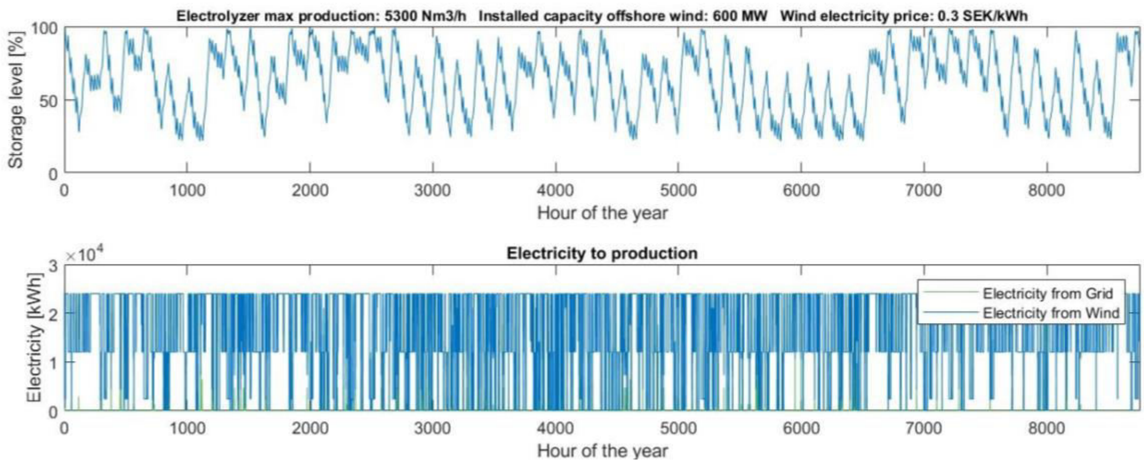

Figure 37. Plots of the simulated PEM system with electricity utilized from the grid and a 600 MW wind farm, using a new LRC storage at 30 bar operating pressure and wind electricity 0.3 SEK per kWh.

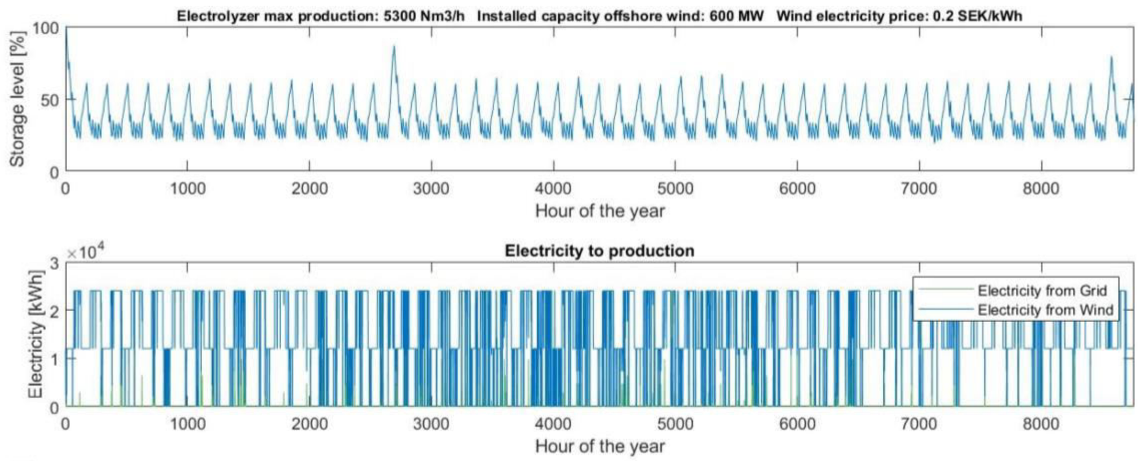

Figure 38. Plots of the simulated PEM system with electricity utilized from the grid and a 600 MW wind farm, using a new LRC storage at 30 bar operating pressure and wind electricity 0.2 SEK per kWh.

Table 20. Percentage share of electricity utilized from wind and grid for wind electricity prices 0.2-0.6 SEK per kWh and installed wind capacities of 50 MW and 600 MW.

Installed wind capacity [MW]	Wind electricity price [SEK/kWh]	Share of electricity utilized from wind [%]	Share of electricity utilized from grid [%]
50	0.2	66.3	33.7
50	0.3	72.5	27.5
50	0.4	76.3	23.7
50	0.5	77.1	22.9
50	0.6	77.3	22.7
600	0.2	89.4	10.6
600	0.3	93.1	6.9
600	0.4	94.4	5.6
600	0.5	95.5	5.5
600	0.6	95.6	5.4

The results from the simulations for the AEL system with electricity supply from the grid and wind farms with installed capacity 600 MW, using a new LRC storage at 30 bar operating pressure and demand case 100% are shown in Figures 39-40. For the AEL system, the hydrogen production is constant and for that reason the patterns in storage level are very similar. The storage level fluctuates with 52 peaks over the simulated year due to the storage being emptied during high demand on weekdays, and then refilled during weekends when the demand was lower. The plots of the electricity source show that for the case with 600 MW installed wind capacity, 90 percent of the electricity is utilized from the wind farms. For 50 MW installed wind capacity, a larger share of electricity from the grid is utilized and the electricity from wind power makes up 67 percent over the simulated year. The plots of 400 MW and 250 MW were not included in the report since they show the same trends as the wind farms with 50 MW and 600 MW installed wind capacity.

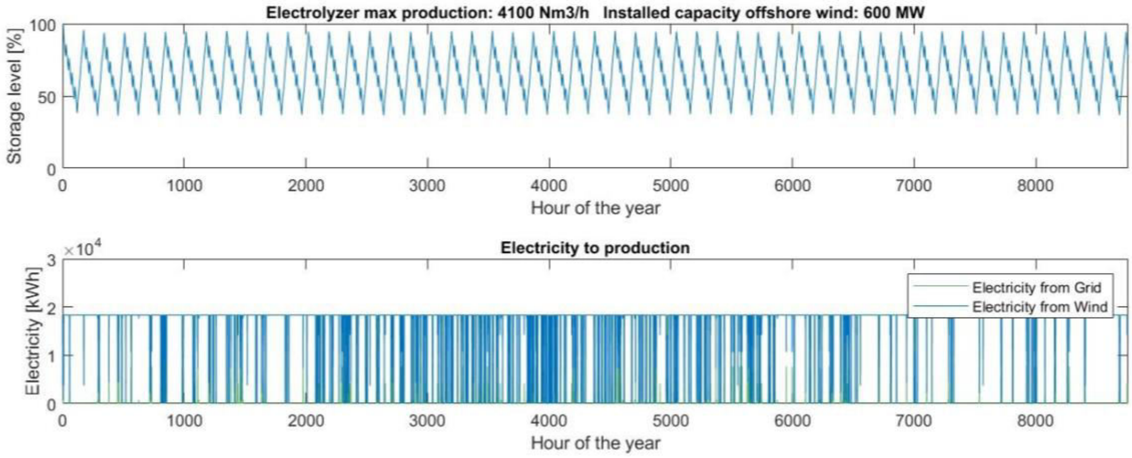

Figure 39. Plots of the simulated AEL system with electricity utilized from the grid and a 600 MW wind farm with a new LRC storage at 30 bar operating pressure.

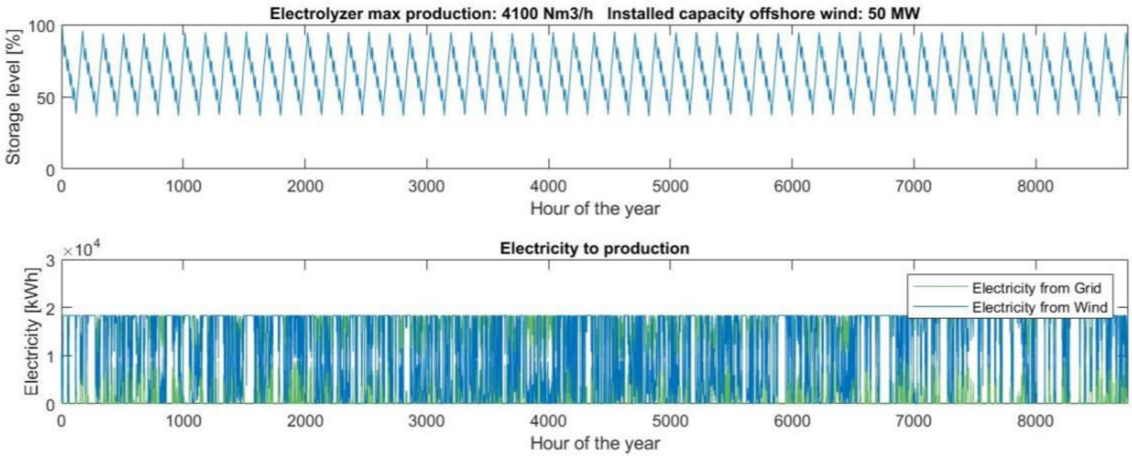

Figure 40. Plots of the simulated AEL system with electricity utilized from the grid and a 50 MW wind farm, using a new LRC storage at 30 bar operating pressure.

The results from the MATLAB simulations for a PEM system using solely wind electricity as power source for wind farms with a capacity of 50, 250, 400 and 600 MW can be seen in Figures 42-45. The system used a new LRC operating at 30 bars as storage and the demand case was 100%. Figure 41 shows the trends in wind speed over the simulated year.

As can be seen in Figures 44 and 45, for installed wind capacities of 250 MW and 50 MW the storage is not large enough for the hydrogen production to meet the hydrogen demand during the whole year. The storage runs empty during the summer season, and then recovers during the fall. This can be explained by the fact that there is less wind during the summer compared to winter, and therefore the system needs to be backed-up by the grid to provide sufficient amounts of hydrogen over the whole year.

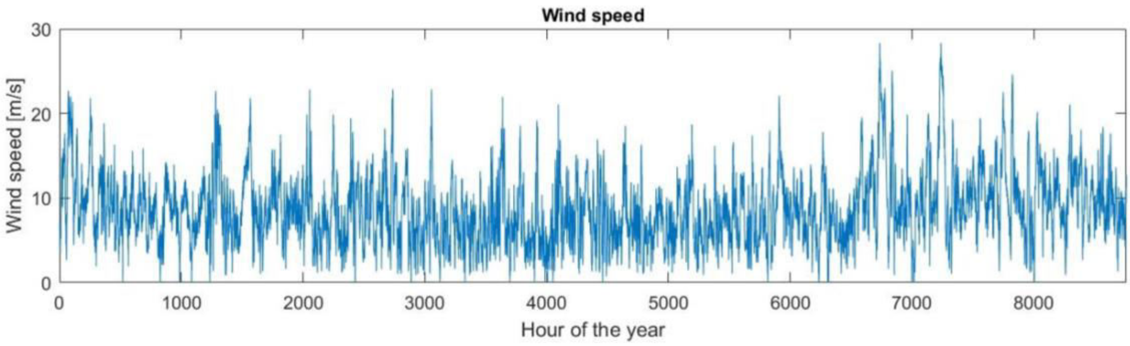

Figure 41. The hourly wind speeds over the simulated year 2017 at Eggegrund, scaled up to the average wind speed at the offshore wind farms location.

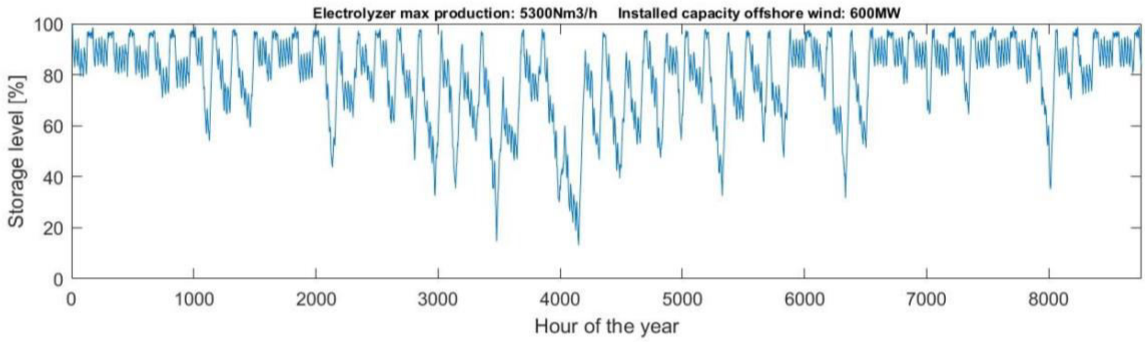

Figure 42. PEM system using solely wind electricity as a power source with installed wind capacity of 600 MW and a new LRC storage with 30 bar operating pressure.

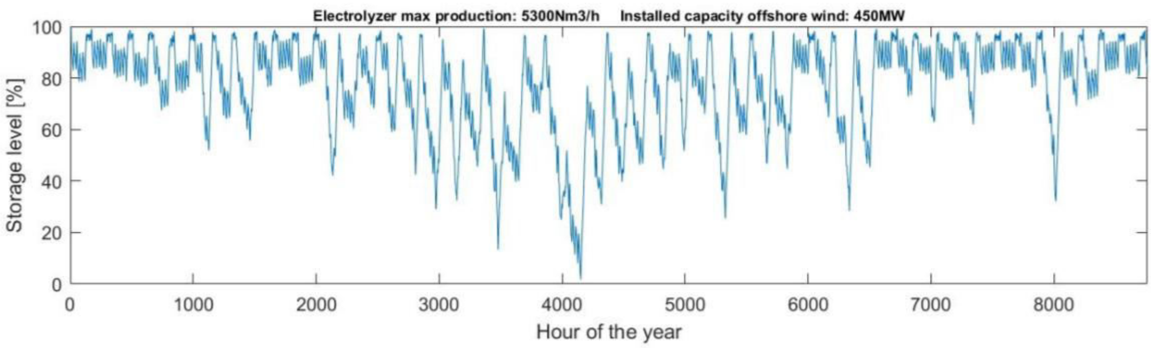

Figure 43. PEM system using solely wind electricity as a power source with installed wind capacity of 450 MW and a new LRC storage with 30 bar operating pressure.

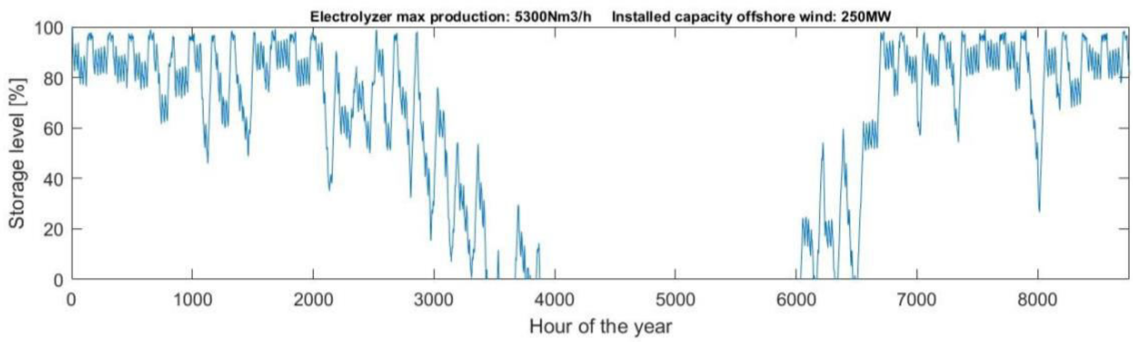

Figure 44. PEM system using solely wind electricity as a power source with installed wind capacity of 250 MW and a new LRC storage with 30 bar operating pressure.

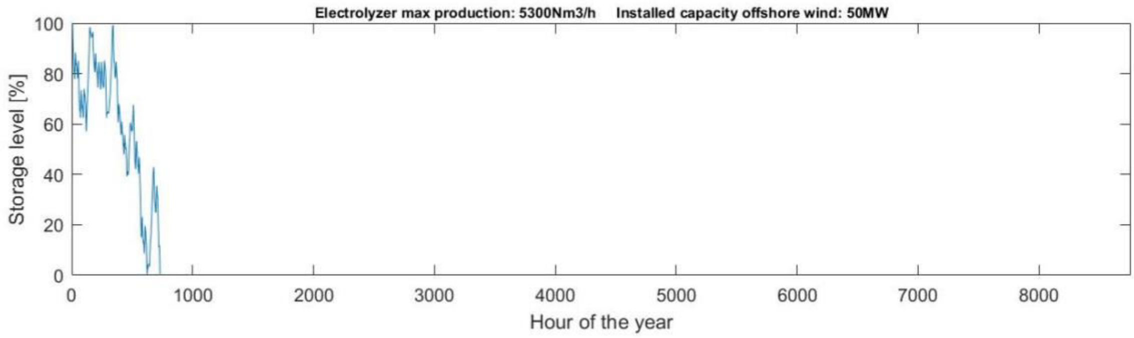

Figure 45. PEM system using solely wind electricity as a power source with installed wind capacity of 50 MW and a new LRC storage with 30 bar operating pressure.

In order for the wind electricity to be sufficient enough to ensure that the storage never went empty, a system with 100% demand with installed wind capacity of 250 MW needed a storage size of 7 times the daily demand and installed wind capacity of 50 MW needed a storage size of 80 times the daily demand. Plots of the storage level for these storage sizes can be seen in Figures 46 and 47. The storage level for the system with 250 MW installed wind capacity went down during the summer and then recovered to the initial level during the fall. The storage level for the system with 50 MW installed wind capacity decreased during the whole year.

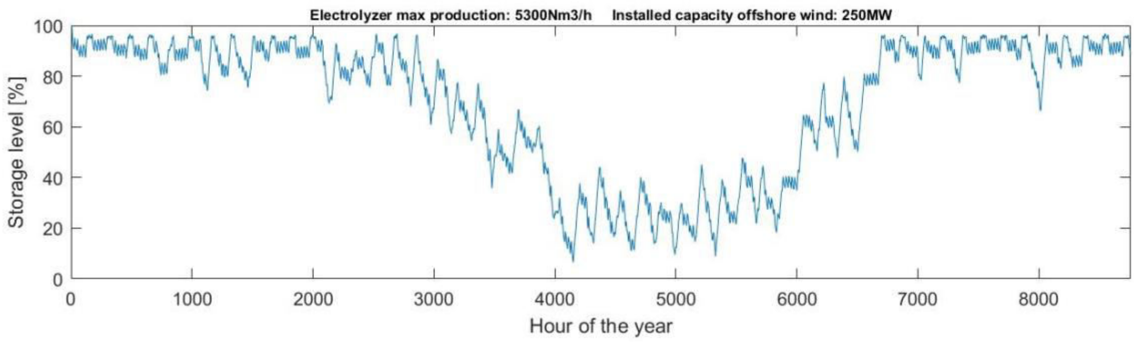

Figure 46. PEM system using solely wind electricity as a power source with installed wind capacity of 250 MW and a new LRC storage with 30 bar operating pressure sized to hold 7 times the daily hydrogen demand.

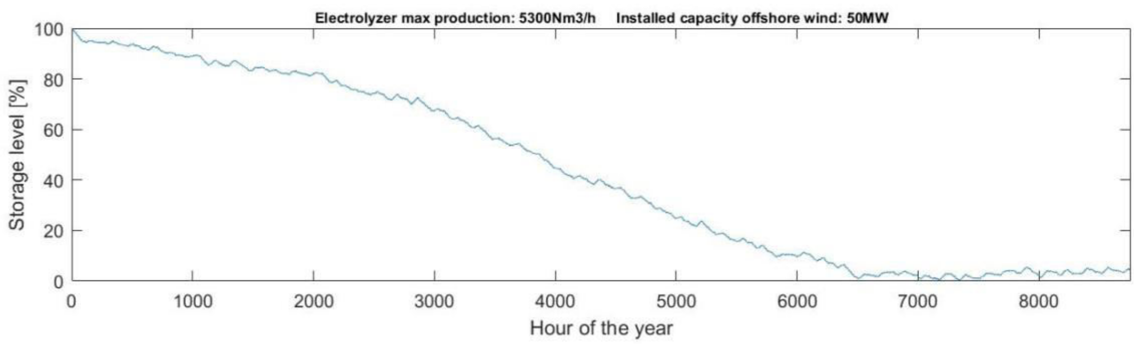

Figure 47. PEM system using solely wind electricity as a power source with installed wind capacity of 50 MW and a new LRC storage with 30 bar operating pressure sized to hold 80 times the daily hydrogen demand.

Table 21 shows the storage sizes needed to ensure that the storage never goes empty for the different installed wind farm capacities and the different demand cases using solely wind power as an electricity source. The numbers in the table for each case represents how many times larger the storage would need to be compared to the average daily demand.

Table 21. The storage dimensions needed to meet the hourly demand for the different installed wind farm capacities and demand scenarios. The numbers represent how many times larger the storage would need to be compared to the average daily demand.

Installed wind capacity (MW)	Demand case 15%	Demand case 50%	Demand case 100%	Demand case 160%
50	5 x	32 x	80 x	132 x
250	3 x	3 x	7 x	17 x
450	3 x	3 x	4 x	7 x
600	3 x	3 x	3 x	4 x

6.1.2 LCOH results for Gävle Hamn

The results showed that higher wind electricity prices resulted in a higher LCOH compared to lower wind electricity prices. The LCOH for different production cases and storage options for the demand case 100% can be seen in Figures 48-50. The figures also show that for the demand case 100%, using a new LRC for storage always resulted in the lowest LCOH compared to the other storage options. Using vessels as storage resulted in the highest LCOH for all production cases.

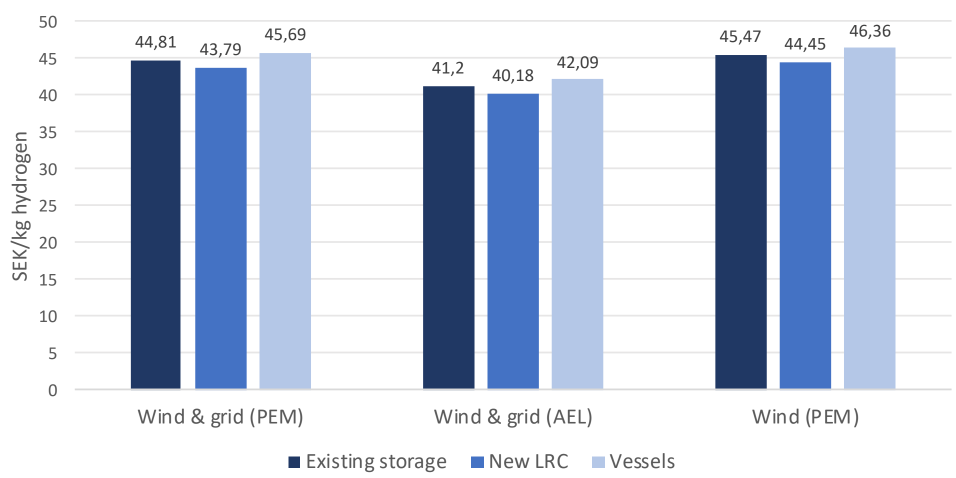

Figure 48. LCOH for all storage and production cases with installed wind farm capacity of 600 MW and wind electricity price 0.6 SEK per kWh.

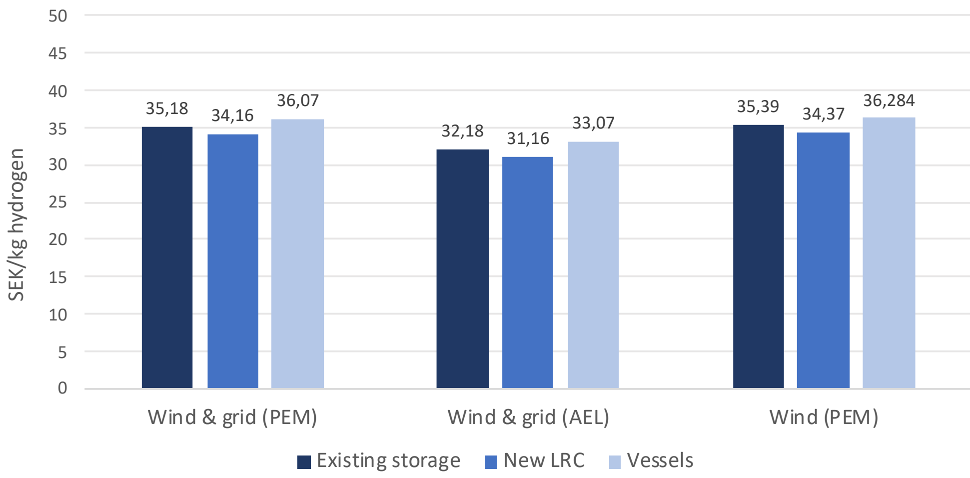

Figure 49. LCOH for all storage and production cases with installed wind farm capacity of 600 MW and wind electricity price 0.4 SEK per kWh.

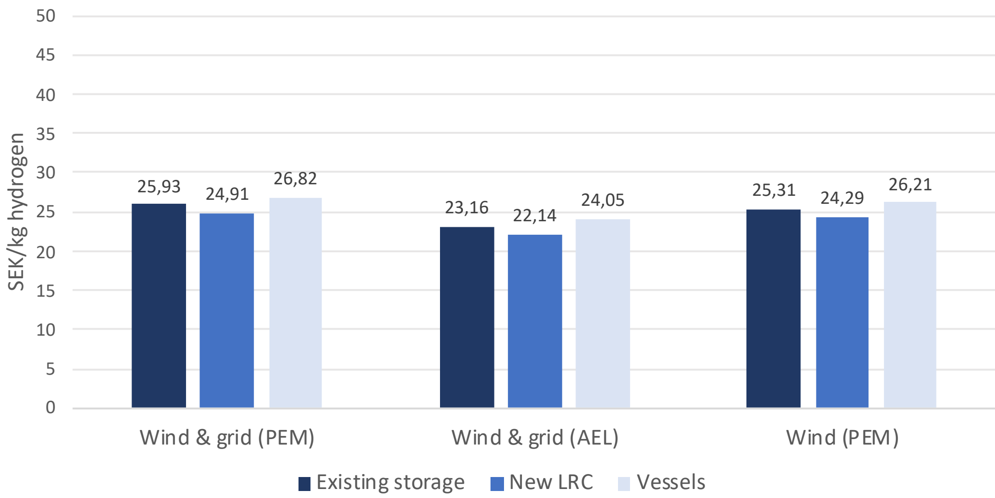

Figure 50. LCOH for all storage and production cases with installed wind farm capacity of 600 MW and wind electricity price 0.2 SEK per kWh.

As can be seen in Figure 51, the wind electricity prices influenced which electricity source was most favorable to use for the hydrogen production. With low wind electricity prices, the PEM system using only wind electricity as power supply had a lower LCOH than the system with both wind and grid. However, for higher wind electricity prices it had the highest LCOH of the production cases. The AEL system resulted in the lowest LCOH for all wind electricity prices.

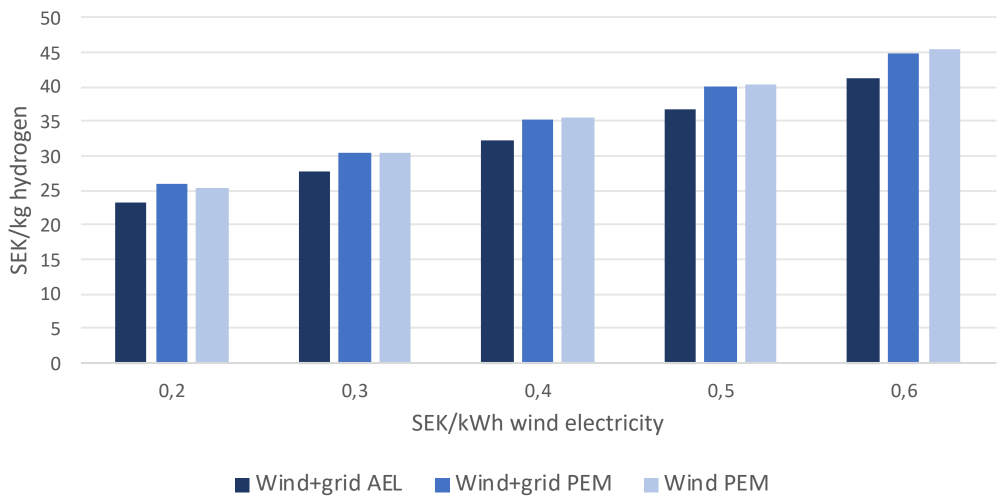

Figure 51. LCOH for the three production cases with 600 MW installed wind farm capacity for different wind electricity prices.

The most financially preferable storage option differs depending on the demand case. The LCOH for the different cases and demand scenarios for wind electricity prices 0.2-0.6 SEK per kWh can be seen in Tables 22-25 for 600 MW installed wind capacity.

Table 22. LCOH (SEK per kg) for demand case 15%, installed wind capacity 600 MW and wind electricity prices 0.2-0.6 SEK per kWh.

Production case	Existing cavern	New LRC	Vessels
Wind PEM	56.22-71.34	49.44-69.59	31.916-52.07
Wind & grid PEM	56.68-75.97	49.91-69.18	32.366-51.57
Wind & grid AEL	54.84-73.40	46.05-66.61	30.529-49.10

Table 23. LCOH (SEK per kg) for demand case 50%, installed wind capacity 600 MW and wind electricity prices 0.2-0.6 SEK per kWh.

Production case	Existing cavern	New LRC	Vessels
Wind PEM	29.77-49.93	27.73-47.89	26.21-46.36
Wind & grid PEM	30.29 -49.49	28.25-47.46	26.72-45.93
Wind & grid AEL	29.20- 47.51	27.17-45.48	25.64-43.95

Table 24. LCOH (SEK per kg) for demand case 100%, installed wind capacity 600 MW and wind electricity prices 0.2-0.6 SEK per kWh.

Production case	Existing cavern	New LRC	Vessels
Wind PEM	25.31-45.47	24.29-44.45	26.21-46.36
Wind & grid PEM	25.93-44.97	24.91-43.95	26.82-45.86
Wind & grid AEL	23.16-41.20	22.14-40.18	24.05-42.09

*Table 25. LCOH (SEK per kg) for demand case 160%, installed wind capacity 600 MW and wind electricity prices 0.2-0.6 SEK per kWh. * represents that the storage ran empty and therefore the hydrogen production does not meet the hydrogen demand using solely wind.*

Production case	Existing cavern	New LRC	Vessels
Wind PEM	22.01 - 42.16*	21.46 - 41.61*	24.31- 44.46*
Wind & grid PEM	22.61 - 41.47	22.15 - 40.92	25.00 - 43.77
Wind & grid AEL	20.76 - 38.46	20.21 - 37.91	23.06 - 40.76

For the demand case 15%, the financially beneficial storage option was using vessels which can be seen in Figure 52. This was also the case for demand case 50% which can be seen in Figure 53. However, for the demand case 100% constructing a new LRC became the most financially beneficial option and repurposing existing underground storage the second most beneficial option in terms of LCOH. This is illustrated in Figure 54.

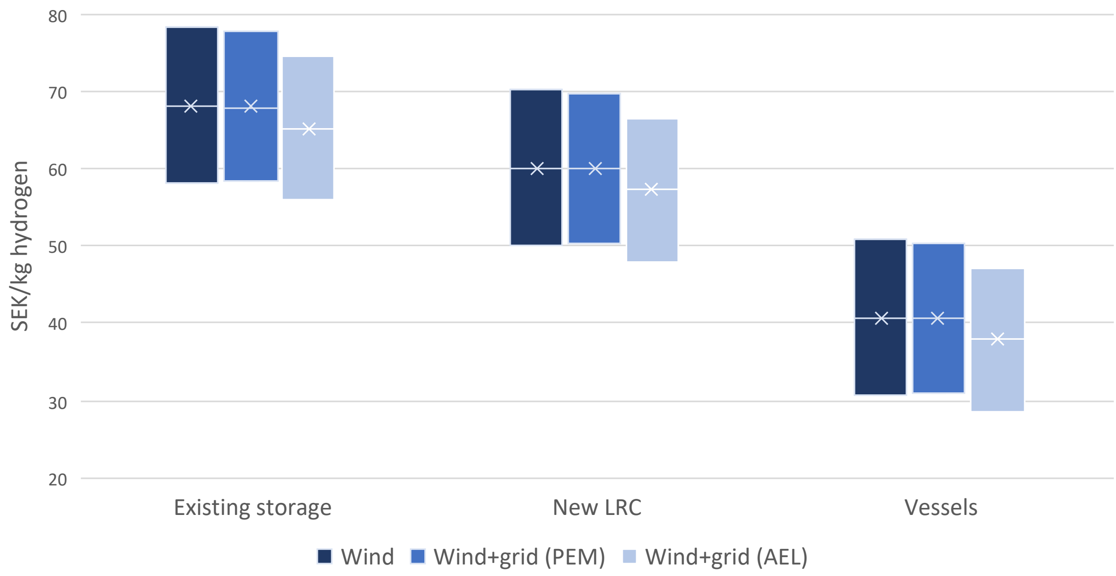

Figure 52. The LCOH range of the three production cases and storage options for demand case 15%.

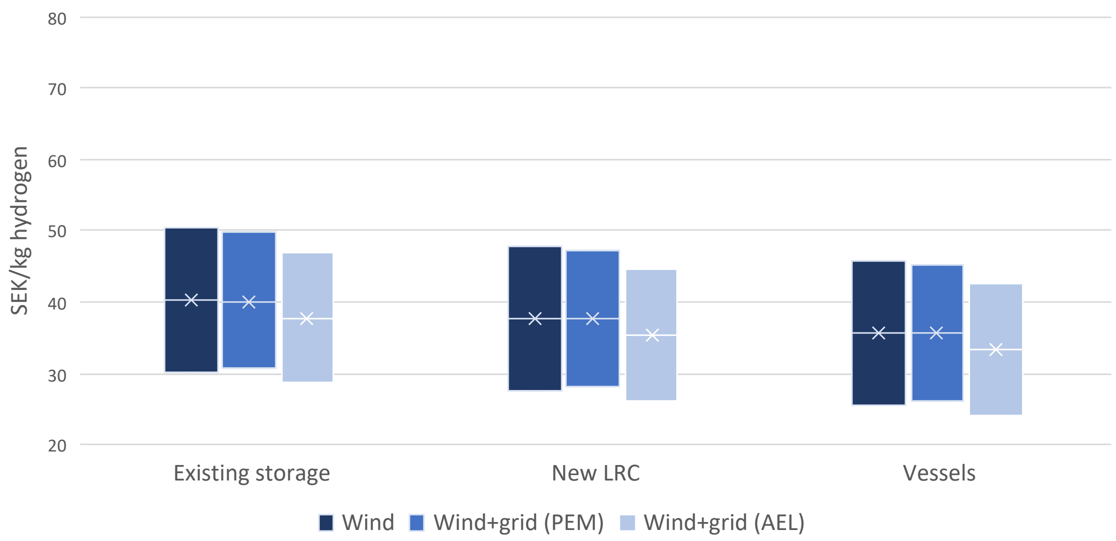

Figure 53. The LCOH range of the three production cases and storage options for demand case 50%.

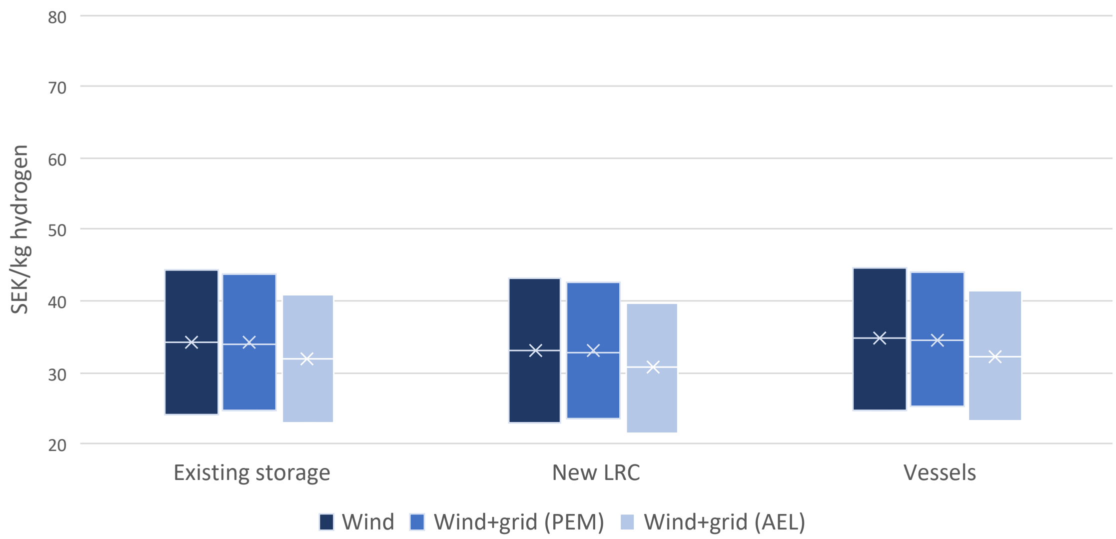

Figure 54. The LCOH range of the three production cases and storage options for demand case 100%.

The demand case 160%, presented in Figure 55, followed the same trend as the previous demand cases. It can be seen that the LCOH of the repurposed existing storage came closer to the LCOH of the new LRC. However, for the production case with wind electricity as the only power source, even the largest wind farms with an installed capacity of 600 MW did not supply enough electricity for the hydrogen production to ensure that the storage never ran empty. As was presented earlier in section 6.1.1, the storage would need to be increased to a size that holds four times the daily demand. This means that for the repurposed existing unit, the storage volume was not large enough to be able to use wind electricity exclusively as a power source to meet the demand of 160 percent. The LCOH for the cases using solely wind power as an electricity source are represented with red bars seen in Figure 55.

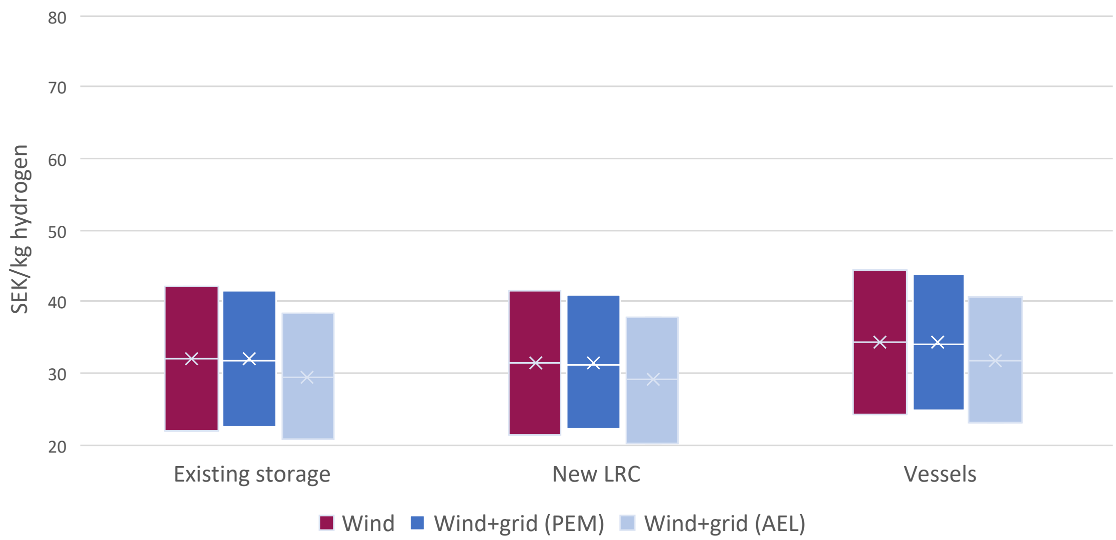

Figure 55. LCOH range of the three storage cases and storage alternatives for demand case 160%. The hydrogen production using solely wind electricity is marked by red bars to illustrate that the electricity supply was not enough to meet the hydrogen demand for the simulated storage size.

Plots of the decreasing LCOH for the different storage alternatives as a result of higher demand can be seen in Figures 56 and 57. Figure 56 includes two different curves for each storage case, one for the highest LCOH, with wind electricity price 0.6 SEK per kWh, and one for the lowest LCOH with wind electricity price 0.2 SEK per kWh. The point of intersection where vessels are no longer the most financially beneficial storage option in terms of LCOH is marked by red dotted circles. Figure 57 shows the plots of the different storage cases for the wind electricity price 0.4 SEK per kWh. The trend is the same when simulating with an AEL system.

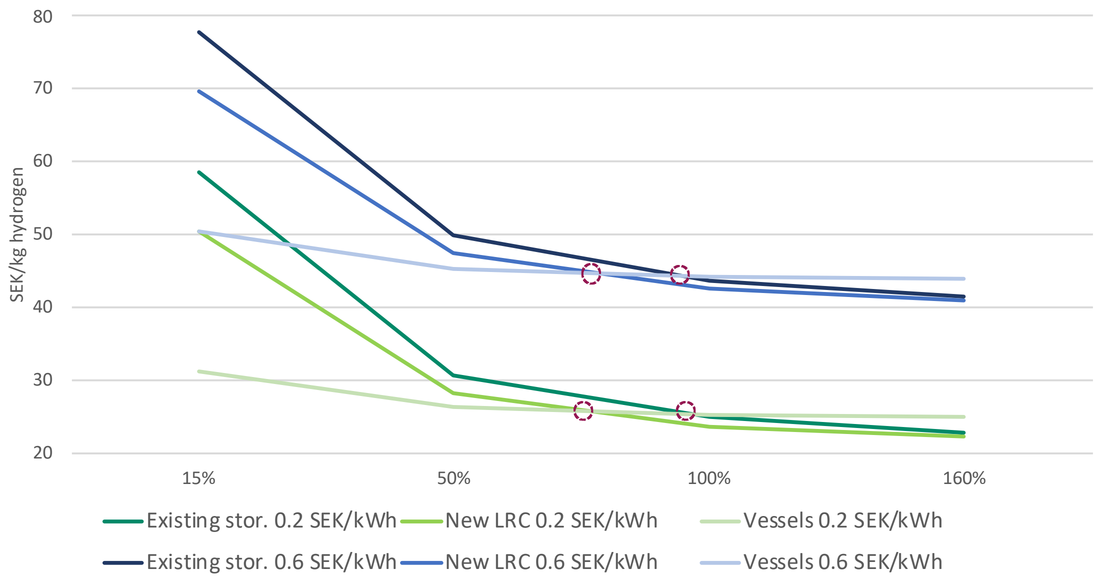

Figure 56. LCOH of PEM system with electricity supply from wind and grid for the different storage options. Wind electricity prices 0.2 and 0.6 SEK per kWh.

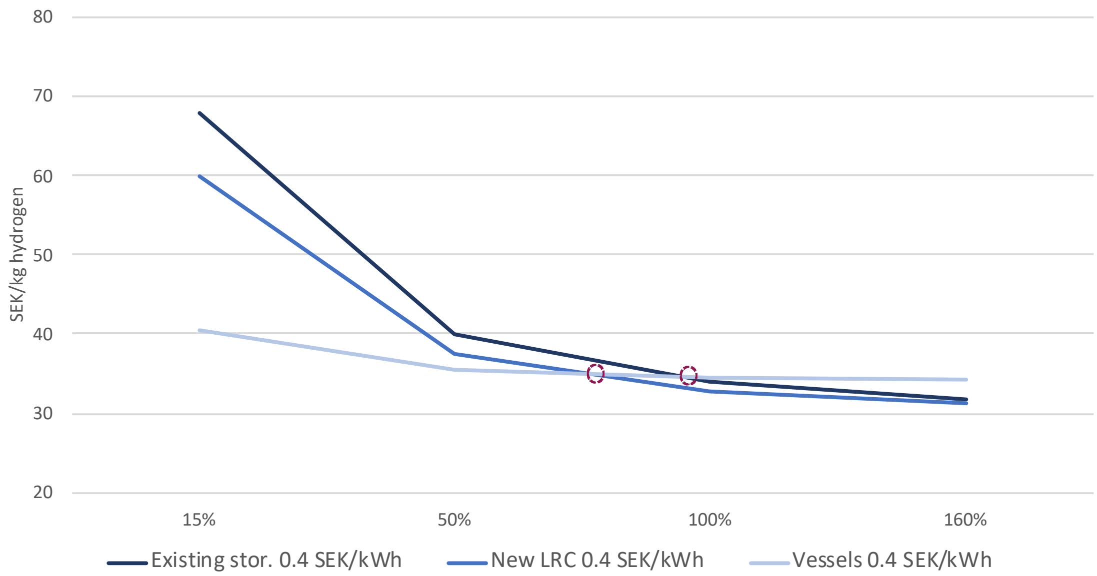

Figure 57. LCOH of PEM system with electricity supply from wind and grid for the different storage options. Wind electricity prices 0.4 SEK/kWh.

6.2 Independent Refueling Stations in Sundsvall and Södertälje

This section will present the results regarding the independent refueling stations in Sundsvall and Södertälje. The first part presents the results from the simulations in MATLAB, and the second part contains the LCOH results.

6.2.1 Simulations in MATLAB

The simulations in MATLAB gave different results depending on the location, demand case and electrolysis technology. Plots of the different demand cases 5, 10 and 15% with AEL electrolysis for Sundsvall can be seen in Figures 58-60. The plots of Södertälje showed the same trends and they were therefore not deemed necessary to include in the report. The figures show the storage level for each hour over the simulated year. Since the AEL system does not regulate the hydrogen production depending on the electricity prices, the storage level was kept relatively constant.

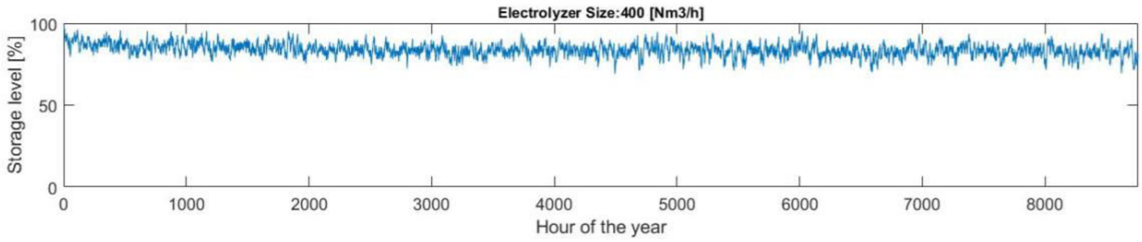

Figure 58. Refueling station connected to AEL system in Sundsvall with demand case 5%.

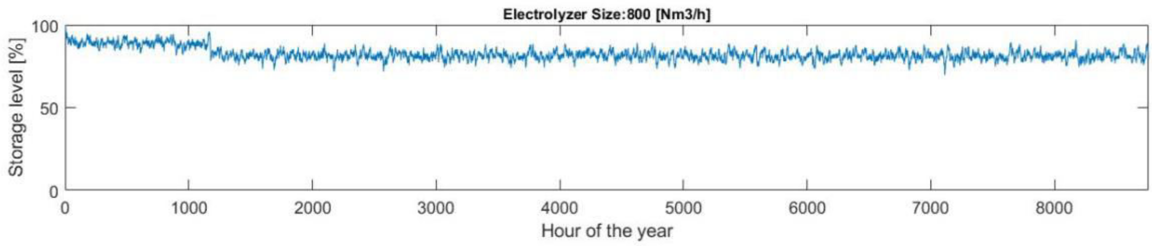

Figure 59. Refueling station connected to AEL system in Sundsvall with demand case 10%.

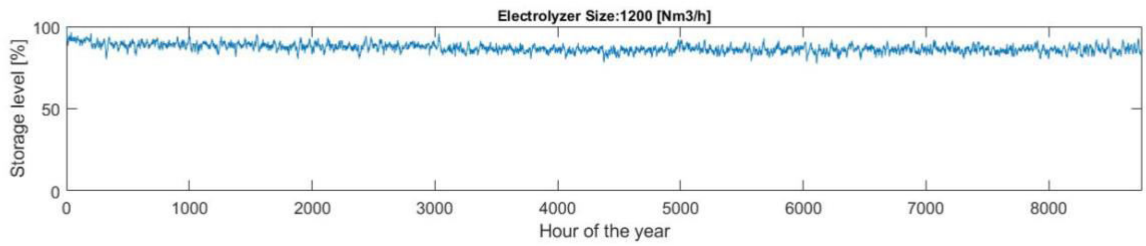

Figure 60. Refueling station connected to AEL system in Sundsvall with demand case 15%.

Plots of the demand case 15% using a PEM electrolyzer for the location Södertälje can be seen in Figures 61-65. Plots of the demand cases 5 and 10% as well as all Sundsvall cases show the same trends and are therefore not presented in the report. The figures each contain two plots that show the storage level for each hour over the year simulated as well as the electricity prices for the corresponding hours. In the plots of the electricity prices a red line has been included representing the threshold prices. Since the PEM system regulated the hydrogen production depending on the electricity prices, the storage level fluctuated more compared to the AEL system. For the higher threshold prices of 0.4 SEK per kWh and 0.35 SEK per kWh the system produced hydrogen at maximum capacity at the majority of the hours of the year whereas for the lower threshold prices of 0.2 and 0.25 SEK per kWh, the system operated at a base production rate during a majority of the time. At threshold price 0.3 SEK per kWh shown in Figure 63, the storage level fluctuated more. This also resulted in the lowest LCOH which will be presented in section 6.2.2.

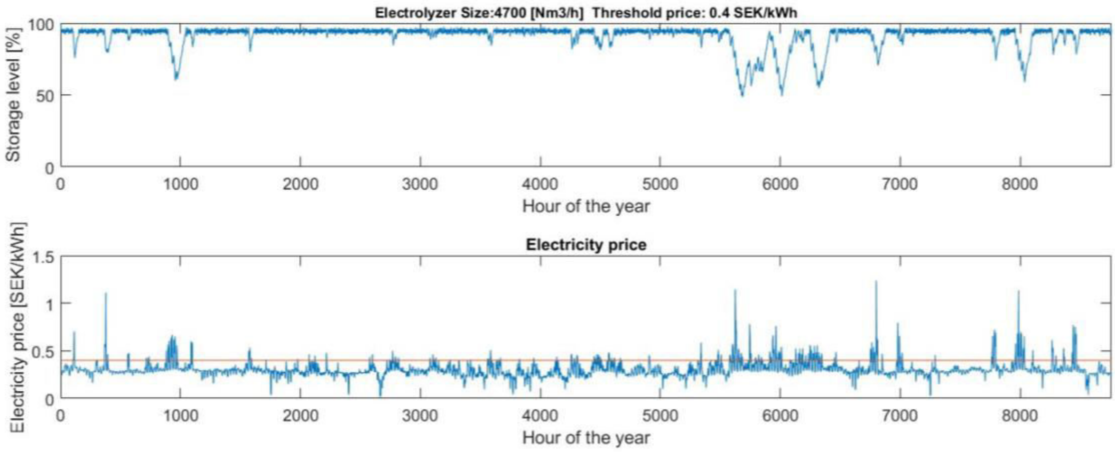

Figure 61. Refueling station connected to PEM system in Södertälje with demand case 15% with threshold price of 0.4 SEK per kWh.

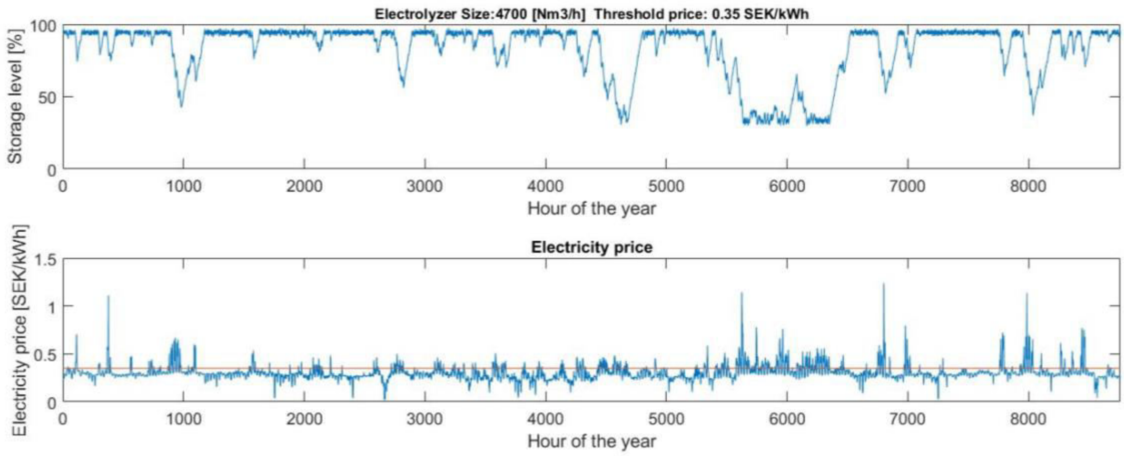

Figure 62. Refueling station connected to PEM system in Södertälje with demand case 15% with threshold price of 0.35 SEK per kWh.

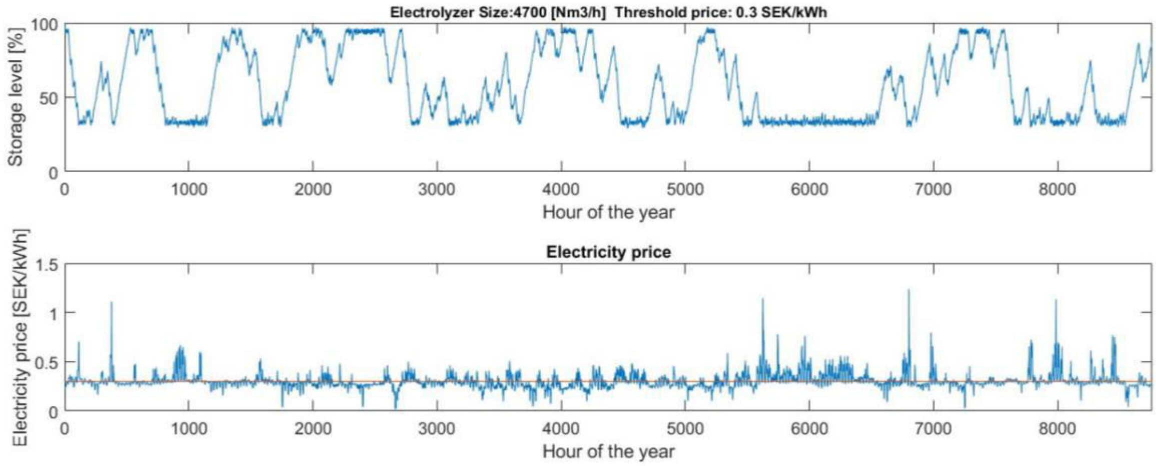

Figure 63. Refueling station connected to PEM system in Södertälje with demand case 15% with threshold price of 0.3 SEK per kWh.

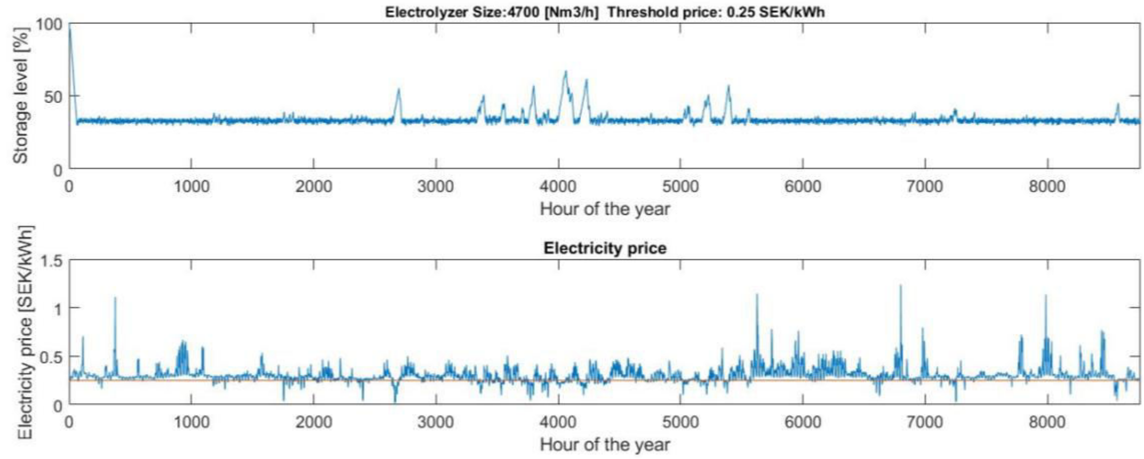

Figure 64. Refueling station connected to PEM system in Södertälje with demand case 15% with threshold price of 0.25 SEK per kWh.

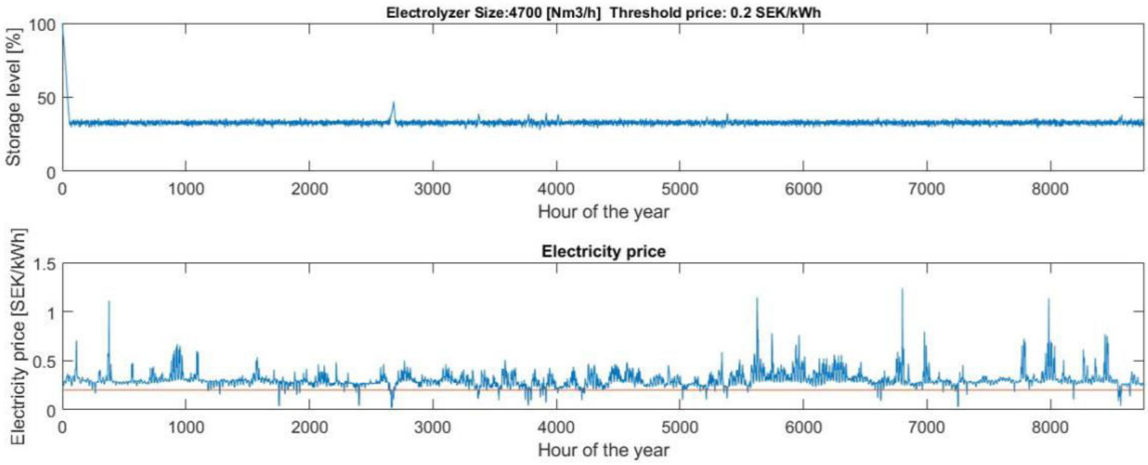

Figure 65. Refueling station connected to PEM system in Södertälje with demand case 15% with threshold price of 0.2 SEK per kWh.

6.2.2 LCOH Results for the Refueling Stations

The results of the simulations for the AEL systems in Sundsvall and Södertälje for the different demand cases can be seen in Figure 66. It shows that larger demand resulted in lower LCOH. The highest LCOH for Södertälje is approximately the same as the lowest LCOH for Sundsvall, which is reasonable considering that they had the same installed electrolyzer capacity.

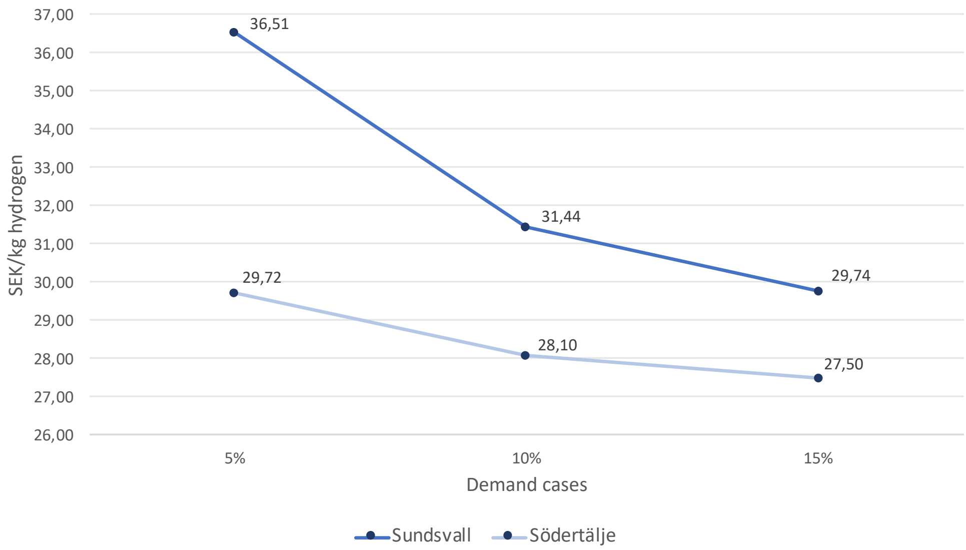

Figure 66. LCOH for AEL systems in Södertälje and Sundsvall for different demand cases 5, 10 and 15 %.

The results from the simulations for the PEM systems in Sundsvall and Södertälje for the different demand cases and threshold prices can be seen in Figure 67 and 68. The lowest LCOH for all demand cases at the two locations was achieved with the threshold prices 0.3 and 0.35 SEK per kWh. The LCOH decreases with increasing demand, which explains the LCOH being lower in Södertälje than in Sundsvall.

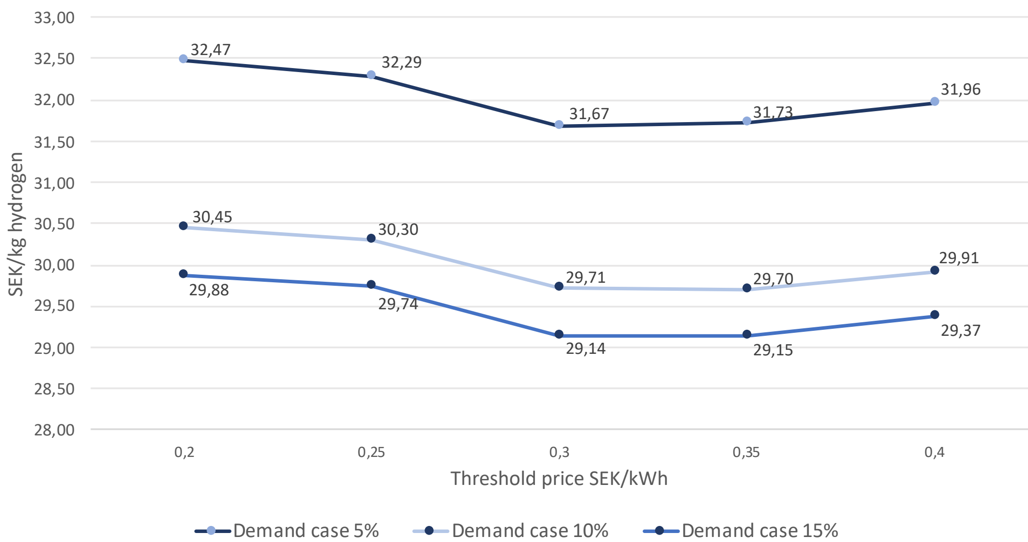

Figure 67. Varying LCOH of hydrogen for the PEM system in Södertälje for different demand cases and threshold prices.

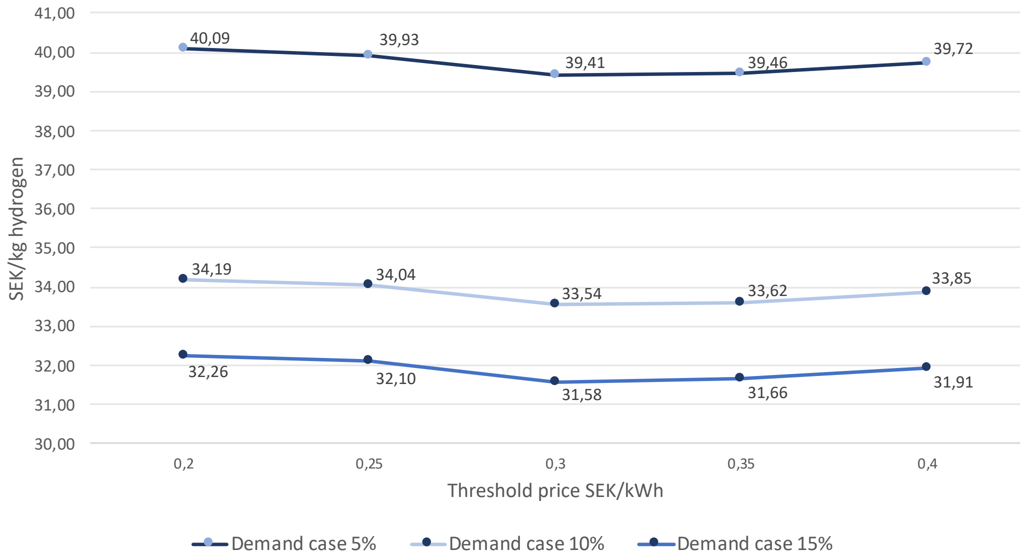

Figure 68. Varying LCOH of hydrogen for the PEM system in Sundsvall for different demand cases and threshold prices.

6.3 Sensitivity Analysis

In the following section, the results from the sensitivity analyses will be presented. The aim of the first sensitivity analysis was to investigate what impact changes in future electricity prices could have on the LCOH. The second sensitivity analysis aimed to investigate how the predicted decrease in electrolyzer prices could affect the LCOH. The third analysis was based on the uncertainty of the assumed pressure in the underground LRC storage units in Gävle Hamn, and how a larger pressure might affect the LCOH. Lastly, the effect of potential subsidies for the construction of a new LRC was investigated.

6.3.1 Future Electricity Prices

The impact of future electricity prices was investigated using two different methods. The first compared a 25 percent increase as well as a 25 percent decrease of electricity prices to the original case to investigate how this would affect the LCOH. The second method was based on a comparison with Denmark's electricity prices over the simulated year to reflect how Swedish electricity prices might change with the introduction of a larger share of renewables in the energy system.

The results from the 25 percent increase and decrease in electricity prices for the PEM and AEL systems in Gävle Hamn with wind power and grid as electricity sources are presented in Tables 26 and 27. Lower electricity prices resulted in decreasing LCOH for both the AEL and PEM system. A system with 50 MW installed wind capacity turned out to be more sensitive to changes in the electricity price than a system with 600 MW installed wind capacity. For the AEL system the changes in electricity prices for different wind electricity prices (0.2-0.6 SEK per kWh) were constant. For the system with a PEM electrolyzer however, the change of the LCOH was dependent on the wind electricity price. For both 50 MW and 600 MW installed wind capacities, the largest change in LCOH observed was with a wind electricity price 0.2 SEK per kWh whereas the smallest change was for 0.6 SEK per kWh.

Table 26. LCOH for the original case, a 25 percent increase and a 25 percent decrease for an AEL system for different installed wind capacities and wind electricity prices.

Installed wind capacity	Wind electricity price [SEK/kWh]	LCOH low electricity price (AEL)	LCOH original electricity price (AEL)	LCOH high electricity price (AEL)
50	0.2	21.55	22.82	24.09
50	0.4	28.29	29.56	30.83
50	0.6	35.04	36.30	37.57
600	0.2	21.23	21.63	22.04
600	0.4	30.25	30.65	31.06
600	0.6	39.27	39.67	40.08

Table 27. LCOH for the original case, a 25 percent increase and a 25 percent decrease for a PEM system for different installed wind capacities and wind electricity prices.

Installed wind capacity	Wind electricity price [SEK/kWh]	LCOH low electricity price (PEM)	LCOH original electricity price (PEM)	LCOH high electricity price (PEM)
50	0.2	23.55	24.90	26.25
50	0.4	31.15	31.99	32.92
50	0.6	39.04	39.87	40.70
600	0.2	23.14	23.57	24.00
600	0.4	32.69	32.85	33.02
600	0.6	42.34	42.50	42.67

The results from the 25 percent increase and decrease in electricity prices for the PEM and AEL systems in Gävle Hamn with wind power and grid as electricity sources are presented in Table 28. As can be seen, the LCOH for the PEM electrolyzer cases increased and decreased with around 3.5 SEK per kg compared to the original case for both Sundsvall and Södertälje. The threshold price achieving the lowest LCOH also changed for both sensitivity cases with 0.4 SEK per kWh as the optimal threshold price for high electricity prices and 0.25 SEK per kWh for the low electricity prices. For the AEL electrolyzer case, the LCOH increased and decreased with around 3.65 SEK per kg compared to the original case for both Sundsvall and Södertälje.

Table 28. LCOH for the original case, a 25 percent increase and a 25 percent decrease for both PEM and AEL systems at the refueling stations in Sundsvall and Södertälje with 15 percent demand.

Location	Production case	LCOH low electricity price [SEK/kg]	LCOH original electricity price [SEK/kg]	LCOH high electricity price [SEK/kg]
Sundsvall	PEM	28.04	31.58	35.08
Sundsvall	AEL	26.12	29.74	33.39
Södertälje	PEM	25.51	29.14	32.56
Södertälje	AEL	23.83	27.50	31.20

When the Danish electricity price data from 2017 was applied to the simulation, this resulted in a lower LCOH for the refueling stations in Sundsvall and Södertälje when using a PEM system. The results can be seen in Tables 29 and 30.

Table 29. The LCOH for a PEM system in Södertälje, demand case 15 % for different threshold prices with both Danish and Swedish electricity price fluctuations. The difference in yearly production cost between the two cases is also presented.

Threshold Price [SEK/kWh]	Danish LCOH [SEK/kg]	Swedish LCOH [SEK/kg]	Yearly production cost difference [SEK]
0.2	29.60	29.89	792 769
0.25	29.42	29.75	890 515
0.3	28.87	29.15	756 397
0.35	28.60	29.15	1 511 144
0.4	29.18	29.38	554 209

Table 30. The LCOH for a PEM system in Sundsvall, demand case 15%, for different threshold prices with Danish and Swedish electricity price fluctuations. The difference in yearly production cost between the two cases is also presented.

Threshold Price [SEK/kWh]	Danish LCOH [SEK/kg]	Swedish LCOH [SEK/kg]	Yearly production cost difference [SEK]
0.2	31.99	32.27	249 960
0.25	31.81	32.11	262 531
0.3	31.20	31.59	340 645
0.35	31.02	31.67	573 901
0.4	31.58	31.92	302 671

For the Gävle Hamn case, the simulations showed a small increase in LCOH when applying Danish fluctuations. The difference between the Swedish and Danish fluctuation cases for the different wind electricity prices, however, were almost identical ranging from 0.01-0.08 SEK per kg. The results are shown in Table 31.

Table 31. The LCOH (SEK/kg) for a PEM system in Gävle Hamn, demand case 100 %, for different threshold prices with Danish (DK) and Swedish (SE) electricity price fluctuations. The results are shown for installed wind capacities 50 MW and 600 MW.

Threshold prices [SEK/kWh]	DK 50 MW [SEK/kg]	SE 50 MW [SEK/kg]	DK 600 MW [SEK/kg]	SE 600 MW [SEK/kg]
0.2	24.74	24.69	23.40	23.37
0.4	31.81	31.74	32.61	32.60
0.6	39.62	39.54	42.16	42.14

6.3.2 Electrolyzer Cost Variations

The impact of a reduction in PEM electrolyzer prices based on future predictions can be seen in Table 32. It shows that the LCOH can be decreased with almost 5 SEK per kg compared to the original case if there is a reduction in electrolyzer price of 75 percent. The case of the electrolyzer cost being reduced by 50 percent resulted in a decrease of LCOH by approximately 3 SEK per kg. For a 25 percent reduction in the electrolyzer prices a reduction in LCOH of approximately 1.5 SEK per kg was achieved.

Table 32. LCOH (SEK/kg) for a PEM system, demand case 100%, using wind and grid as electricity sources for production, installed wind capacities 50 MW and 600 MW for different wind electricity prices. 25, 50 and 75 percent reduction in electrolyzer costs.

Wind capacity [MW]	Wind electricity price [SEK/kWh]	Electrolyzer cost 100 % [SEK]	75 % cost reduction [SEK]	50% cost reduction [SEK]	25% cost reduction [SEK]
50	0.2	24.69	19.98	21.55	23.12
50	0.4	31.74	27.03	28.60	30.17
50	0.6	39.54	34.83	36.40	37.97
600	0.2	23.37	18.66	20.23	21.80
600	0.4	32.60	27.89	29.46	31.03
600	0.6	42.14	37.43	39.00	40.57

Multiplying the yearly demand with the LCOH (SEK per kg) gave the total yearly production cost of hydrogen as presented in Table 33. Comparing the difference between the cases show that a decrease in electrolyzer cost of 75 percent results in yearly saving of approximately 15.03 million SEK, 50 percent corresponds to 10.02 million SEK and 25 percent would result in savings of approximately 5.09 million SEK.

Table 33. Total yearly production cost for a PEM system, demand case 100%, using wind and grid as electricity sources for production, installed wind capacities 50 MW and 600 MW for different wind electricity prices. 75, 50, and 25 percent reduction in electrolyzer costs.

Wind capacity [MW]	Wind electricity price [SEK/kWh]	Electrolyzer cost 100% [SEK]	75% cost reduction [SEK]	50% cost reduction [SEK]	25% cost reduction [SEK]
50	0.2	78.78 M	63.75 M	68.76 M	73.77 M
50	0.4	101.27 M	86.24 M	91.25 M	96 26 M
50	0.6	126.16 M	111.13 M	116.14 M	121.15 M
600	0.2	74.57 M	59.54 M	64.5 M	69.56 M
600	0.4	104.02 M	88.99 M	93.99 M	99.01 M
600	0.6	134.46 M	119.43 M	124.44 M	129.45 M

The impact of a reduction in AEL electrolyzer prices based on future predictions can be seen in Table 34. It shows that the LCOH can be lowered by slightly above 3 SEK per kg compared to the original case for a reduction in electrolyzer price of 75 percent. If the electrolyzer prices go down by 25 percent, this resulted in a reduction in LCOH of approximately 1 SEK per kg. The case of electrolyzer cost being reduced by 50 percent resulted in a LCOH lowered by approximately 2 SEK per kg.

Table 34. LCOH (SEK per kg) for an AEL system, demand case 100%, using wind and grid as electricity sources for production, installed wind capacities 50 MW and 600 MW for different wind electricity prices. 75, 50 and 25 percent reduction in electrolyzer costs.

Wind capacity [MW]	Wind electricity price [SEK/kWh]	Electrolyzer cost 100 % [SEK]	75 % cost reduction [SEK]	50% cost reduction [SEK]	25% cost reduction [SEK]
50	0.2	22.62	19.33	20.43	21.53
50	0.4	29.37	26.08	27.17	28.27
50	0.6	36.11	32.82	33.92	35.01
600	0.2	21.44	18.15	19.25	20.34
600	0.4	30.46	27.17	28.27	29.36
600	0.6	39.48	36.19	37.29	38.38

The total yearly production cost of hydrogen as presented in Table 35. Comparing the difference between the cases show that a decrease in electrolyzer cost of 75 percent resulted in yearly saving of approximately 10.5 million SEK, 50 percent corresponded to approximately 6.99 million SEK and 25 percent resulted in savings of approximately 3.48 million SEK.

Table 35. Total yearly production cost for an AEL system, demand case 100%, using wind and grid as electricity sources for production, installed wind capacities 50 MW and 600 MW for different wind electricity prices. 75, 50 and 25 percent reduction in electrolyzer costs.

Wind capacity [MW]	Wind electricity price [SEK/kWh]	Electrolyzer cost 100% [SEK]	75% reduction [SEK]	50% reduction [SEK]	25% reduction [SEK]
50	0.2	72.17 M	68.70 M	65.19 M	61.68 M
50	0.4	93.71 M	90.20 M	86.69 M	83.21 M
50	0.6	115.22 M	111.71 M	108.23 M	104.72 M
600	0.2	68.41 M	64.90 M	61.42 M	57.91 M
600	0.4	97.19 M	93.68 M	90.20 M	86.69 M
600	0.6	125.97 M	122.46 M	118.98 M	115.47 M

The results for the simulations run with the same CAPEX for the PEM and AEL electrolyzer for the refueling station in Södertälje, demand case 15 percent, are presented in Table 36. The results show that with the same CAPEX, the PEM electrolyzer achieves a lower LCOH for all threshold prices except for 0.2 and 0.25 SEK per kWh.

Table 36. LCOH for different production cases and threshold prices with the same electrolyzer CAPEX.

Production case	LCOH [SEK/kg]
PEM, threshold price 0.2 [SEK/kWh]	29.89
PEM, threshold price 0.25 [SEK/kWh]	29.75
PEM, threshold price 0.3 [SEK/kWh]	29.15
PEM, threshold price 0.35 [SEK/kWh]	29.15
PEM, threshold price 0.4 [SEK/kWh]	29.38
AEL	29.52

6.3.3 Operating Pressure and Dimensions of Underground Storage

To investigate how the LCOH for the different storage options would change for different operating pressures, a hypothetical case with 270% demand was introduced. This was the maximum demand the existing storage unit could hold with a pressure of 10 bars. This was compared to the new LRC with 30 bar pressure as previous simulations, and a new LRC case with a pressure of 200 bar. A compilation of the specification for the different storage options evaluated can be seen in Table 37.

Table 37. Specifications for the different storage options evaluated in Gävle Hamn for the demand cases 100 %, 160 % and 270 %.

	Existing storage	New LRC 30 bar	Vessels 40’	New LRC 200 bar
Demand case 100%				
Volume of storage [m^3]	79 184.95	9 708.81	-	1 456.32
Storage capacity [kg]	42 712	26 185	26 400	26 185
Storage Capex [SEK]	202.824 M	148.2 M	225.456 M	107.870 M
Capex Compressor [SEK/kg]	28.35	28.35	28.35	56.71
Demand case 160%				
Volume of storage [m^3]	79 184.95	15 534.09	-	2 330.11
Storage capacity [kg]	42 712	41 895	42 400	41 895.5
Storage Capex [SEK]	202.824 M	166.18 M	362.096 M	111.800 M
Capex Compressor [SEK]	28.35	28.35	28.35	56.71
Demand case 270%				
Volume of storage [m^3]	79 184.95	15 534.09	-	3 932.07
Storage capacity [kg]	42 712	41 895	42 400	70 699
Storage Capex [SEK]	202.824 M	166.18 M	362.096 M	118.140 M
Capex Compressor [SEK]	28.35	28.35	28.35	56.71

Plots of LCOH results from the simulations with the new operating pressures and storage alternatives are shown in Figures 69-70. As can be seen, even with a very large hydrogen demand, constructing a new LRC still results in the lowest LCOH. The results also show that using a higher operating pressure of 200 bars, which enables the construction of a smaller storage, is not financially justifiable. This due to the need for a second compressor before the storage, resulting in higher CAPEX and OPEX.

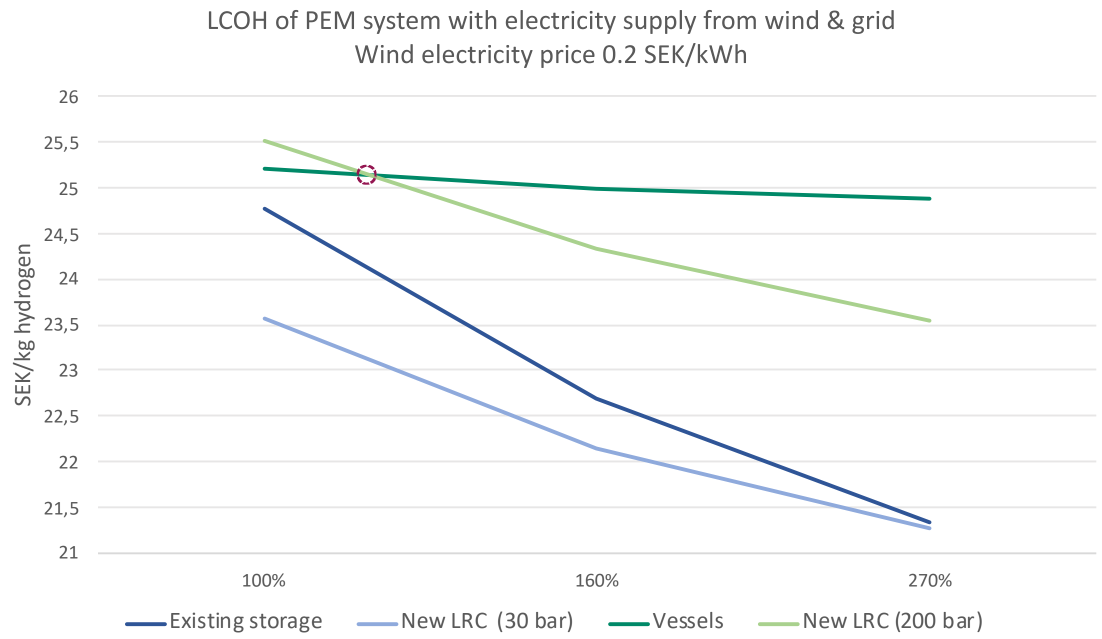

Figure 69. LCOH for different storage alternatives and demand cases for PEM systems with electricity supply from the grid and wind power at wind electricity price 0.2 SEK per kWh.

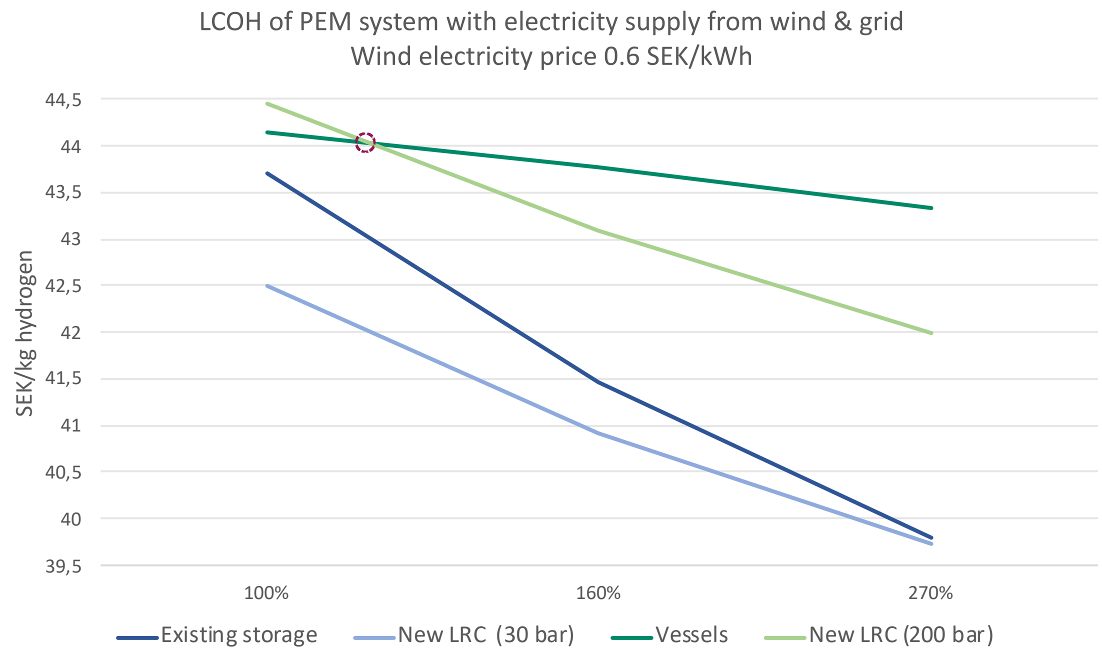

Figure 70. LCOH for different storage alternatives and demand cases for PEM systems with electricity supply from the grid and wind power at wind electricity price 0.6 SEK per kWh.

6.3.4 Storage Subsidies

The results from 25 percent of the investment costs of the storage being subsidized can be seen in Table 38. This resulted in a decrease in LCOH of approximately 0.9 SEK per kg, which corresponds to a yearly production cost reduction of 2.8 million SEK.

Table 38. LCOH (SEK per kg) for the demand case 100% with a PEM electrolyzer with wind and grid as electricity source, 600 MW installed wind capacity and wind electricity prices of 0.2, 0.4 and 0.6 SEK per kWh. Results from simulations with the original and the 25 percent subsidized LRC-storage cost.

Installed Wind Capacity	Wind power [SEK/kWh]	LRC-storage cost 100 % [SEK/kg]	LRC-storage cost 25 % subsidies [SEK/kg]
600	0.2	23.37	22.49
600	0.4	32.60	31.72
600	0.6	42.14	41.26

7. Discussion

In this chapter, the results from the study will be analyzed and discussed. The results depended on a large variety of factors and each section in this chapter will analyze the impact each factor had on the systems. The first section will discuss the impact of the different production cases regarding factors such as electrolyzer technology, electricity source, and price thresholds. The second section will discuss the impact of the different installed wind capacities. The third section will discuss the different storage options and in the fourth, the final LCOH values are interpreted and analyzed. Even if the results show that some solutions are not financially competitive, the fact that clean hydrogen production is a green source of energy can still generate economic value.

7.1 Production Cases

One of the primary factors influencing the results was the selection of the production case. For the Gävle Hamn case, the results depended on whether production with an AEL or PEM electrolyzer was selected, and also on the choice of producing hydrogen using solely wind electricity or including electricity from the grid. A steady production rate with an AEL electrolyzer turned out to be the best strategy with respect to the LCOH for all simulated cases. This can be explained by the fact that lower CAPEX of the AEL had a larger impact on the LCOH than the electricity prices. Even with an installed wind capacity of 50 MW and a wind electricity price at 0.2 SEK per kWh, when the share of wind electricity to the AEL system made up 60 percent of the electricity used, the LCOH was lower than for the PEM system using 100 percent cheap wind electricity.

The LCOH for the PEM system only utilizing electricity from the grid achieved lower LCOH than the PEM system using electricity fed both from the grid and the wind farms for wind electricity prices of 0.2 and 0.3 SEK per kWh, which was reasonable. When the wind electricity price was lower than the average electricity price from the grid, only utilizing electricity produced by the wind farms was a cheaper option than buying electricity from the grid during most hours of the year. However, the system utilizing electricity both from the wind farms and the grid strived to sell as much wind electricity as possible when the electricity price from the grid exceeded the wind electricity price by reducing the hydrogen production. This resulted in the storage level running critically low, forcing the system to increase the production even at times when wind electricity production was low and grid electricity prices were high. This indicates that for wind electricity prices lower than the average electricity price from the grid, the regulation of the PEM electrolyzer should be controlled similar to the system used for the refueling stations. For the refueling stations the system strives to produce more during hours with low electricity prices to be able to reduce production when electricity prices are high. This could be achieved by the system regulating according to the electricity prices and not based on the wind electricity price threshold for the system using both wind power and the grid.

For the PEM electrolyzer cases with wind electricity prices higher than the average electricity price, production of hydrogen using solely wind electricity resulted in a higher LCOH than utilizing both wind and grid electricity. This can be explained by the share of cheaper electricity from the grid being used for the base production at times when the electricity production from the wind farms did not meet the demand for these specific hours.

The ability to regulate the production depending on the electricity prices when using a PEM electrolyzer resulted in higher LCOH but also, in a larger share of wind electricity being utilized for the hydrogen production. This enabled the system to sell wind electricity to the grid when financially beneficial. As the hydrogen production was integrated with the wind farms, achieving a low LCOH was not the main purpose. The purpose was to achieve the highest possible return for the whole system. The return of electricity sold to the grid was not included in the financial calculations in this study but could possibly play an important part when implementing such a system. Using a PEM electrolyzer could also possibly create future opportunities to participate in the frequency and voltage regulation markets. These are prospects that need to be taken into consideration when deciding which electrolyzer technology to use.

The same trends regarding LCOH as in Gävle Hamn could be seen for the refueling stations in Sundsvall and Södertälje. Using a steady production with AEL electrolyzers resulted in lower LCOH than when regulating production depending on electricity prices using a PEM electrolyzer. For the PEM electrolyzer production case, the lowest LCOH was achieved when regulating the production based on a threshold price of 0.3-0.35 SEK per kWh. This was expected considering that it corresponded to the average electricity price. For these cases, the storage level had large fluctuations over the year showing that the system took advantage of the hours with low electricity prices by increasing production and filling up the storage. During hours with high electricity prices, the production was reduced, and the hydrogen stored was used to meet the demand. For higher threshold prices the production was more constant at a high level, much like the

AEL electrolyzer. For lower threshold prices, which resulted in the highest LCOH, the system was operating at a base production rate during more hours. The low production rate resulted in the storage level being critically low more often, forcing the system to increase production to maximum rate even at times with high electricity prices. This indicates that to run a PEM system optimally with respect to the LCOH, the price threshold should be set to the average electricity price. Since electricity prices tend to vary over the year, a dynamic threshold price following these trends would have been more beneficial. To introduce different threshold steps based on the storage level, where e.g. the threshold price is increased when the storage starts running low, could be a way to avoid producing at maximum rate during hours with high electricity prices caused by the storage level being critically low.

Like the system in Gävle Hamn, the higher LCOH for the PEM system is explained by the higher CAPEX of the PEM electrolyzer. However, when simulating with the same CAPEX for the AEL and PEM electrolyzers a lower LCOH was achieved for the PEM system when the production was regulated with threshold prices of 0.3 SEK per kWh and above. This indicates that in a future scenario, when the CAPEX and the two techniques are more similar, producing with a PEM electrolyzer could be more financially beneficial for a system only using electricity from the grid with the aim of achieving the lowest possible LCOH.

The forecasts for the future development of electrolyzer costs unanimously state that there will be a substantial price reduction in the coming years. The cost of the electrolyzer makes up for a relatively large share of the final LCOH. The simulations in the sensitivity analysis showed that a 25-75 percent decrease in electrolyzer CAPEX would result in millions of SEK in cost reductions over a year. For example, a 75 percent reduction in PEM electrolyzer CAPEX resulted in 15 million SEK in yearly savings which corresponds to approximately 24 percent of the total yearly production cost. This would add up to hundreds of millions of savings during the whole lifetime of the electrolyzer. This shows the impact a future reduction in electrolyzer costs would have financially and is also worth taking into account when considering future projects.

Increasing and decreasing electricity prices by 25 percent resulted in a difference in LCOH for Gävle Hamn of approximately 1.3 SEK per kg hydrogen for installed wind capacity of 50 MW and 0.4 SEK per kg hydrogen for installed wind capacity of 600 MW. This indicates that the impact of changes in the electricity price is relatively large since less wind electricity results in a larger change in the LCOH. That means that a smaller wind farm, where more electricity from the grid is being utilized, results in lower LCOH. This was also confirmed when simulating an increase and decrease in electricity prices for the refueling stations, utilizing only power from the grid. A 25 percent decrease of electricity prices turned out to affect the LCOH almost as much as a 75 percent reduction of the electrolyzer cost did. The fact that the optimal threshold price changed with the increased and decreased electricity prices further prove that the optimal threshold price should be based on the average electricity price.

The simulations of Danish electricity price fluctuations scaled to the Swedish prices turned out to be in favor of the PEM systems considering a decrease in LCOH. This shows that using a PEM system with flexible regulation becomes more beneficial with volatile electricity prices. Since the electricity prices are predicted to become more volatile as a result of a larger share of wind power in the future energy system, using PEM electrolyzers for hydrogen production can be beneficial.

7.2 Installed Wind Farm Capacities

The simulations showed that larger installed wind farm capacities resulted in a higher percentage share of wind electricity being utilized for the hydrogen production. This is reasonable considering the aim of the systems integrated with wind power was to utilize as much wind power as possible, except for times when it would be more financially beneficial to sell the wind power to the grid.

For the cases when the electricity supplied to the hydrogen production was solely from the wind farms, the sizes of the wind farms had a major impact on the system. Installed capacities of 50 MW and 250 MW was not enough to keep a sufficient storage level during the whole year for the 100 % demand case. For the case of 250 MW, this was solved by using larger storage equal to seven times the daily demand so that the hydrogen level could recover after the dip during the summer. For the 50 MW case, having a storage corresponding to 80 times the average daily demand managed to keep the storage level above zero for the whole year. However, at the end of the year the storage level was nearly empty, and it is unlikely that it would be able to recover from that low level the following year. For that reason, having a wind farm of 50 MW installed wind capacity for the simulated demand cases was not deemed realistic. The storage could have been increased even more, but chances are that the level would keep dropping over the years. Also, having a storage size to hold 80 times the daily demand means huge investment costs and is not deemed financially justifiable.

The LCOH for the different sized wind farms for the systems using solely wind electricity turned out to be the same. This makes sense considering the electricity from the wind farms is bought at the same electricity price, and the system uses the same amount of wind electricity regardless of the installed wind capacity to meet the hydrogen demand. In a real scenario however, this assumption would be unrealistic. Since the wind power producers and the hydrogen production owners are considered to be a joint venture in these cases, the investment costs of the wind farms would have to be included in the total LCOH. For this, a thorough analysis would have to be made regarding costs of wind turbines, the distance to the mainland, connection fees, water depth, etcetera. The larger the wind farm investment costs, the smaller the percentage share the hydrogen production facility would make of the total project cost. Regarding this study, the total LCOH could possibly be lower for the 450 MW wind farm than the 600 MW. Both sizes of installed wind farm capacities were large enough to meet the needed hydrogen production for a 100% demand case, which means that the 600 MW wind farm can be considered overdimenzioned. In an actual project, this is also something to take into consideration when dimensioning a hydrogen production facility connected to offshore wind farms.

7.3 Storage Options

In Gävle Hamn, the optimal storage option depended on the demand for hydrogen. For the demand cases 15 and 50 percent, vessels turned out to be the most favorable option in terms of LCOH. This is reasonable considering the large investment costs for constructing a new LRC or repurposing the existing storage unit. For 100 and 160 percent demand, a new LRC became the most preferred storage option which confirms the advantages of using underground storage for large hydrogen demand scenarios. Considering that Gävle Hamn AB wants to make a hydrogen transition of the operations in the harbor, this would be the best storage option from a financial perspective. The exact size of a newly constructed LRC would depend on the stakeholders' estimations and expectations of future hydrogen demand.

Based on the results, repurposing the existing storage unit in Gävle Hamn proved not to be financially competitive to the other two storage options. There are however other factors that would need to be taken into account when repurposing the storage to validate this result, such as a more thorough examination of the bedrock. A more thorough investigation might show that the bedrock would not be able to withstand a pressure of even 7.7 bars that was used in the simulations. On the other hand an investigation might prove the opposite, that even larger pressure capacities would be possible. In that case, repurposing the underground storage units could become more financially beneficial than constructing a new LRC. With that said, the sensitivity analysis including simulations of the 270% demand case showed that even with such a large demand, constructing a new LRC still resulted in the lowest LCOH. This implies that unless possible future stakeholders of such a project think that the demand will be larger than three times the demand of the operations in Gävle Hamn, constructing a new LRC would still be the most preferable option.

The sensitivity analysis also included simulations for a new LRC with an operating pressure of 200 bars and a smaller storage volume. For this study, 200 bars resulted in a much higher LCOH compared to an LRC with 30 bars. This was due to high CAPEX and OPEX of including a second compressor in the system. The compressor cost turned out to be more expensive than constructing larger storage that could hold the same amount of hydrogen at 30 bars. The 200-bar storage was even more expensive in terms of LCOH than using vessels for the 100% demand case. This implies that based on this study, this storage option would not be worth pursuing in an actual project. This also shows the large impact the compressor investment and operating costs have on the LCOH. The compressor costs used for the simulations were based on a report from 2017 and not on actual price indications from first-hand sources. Therefore, the relatively large financial impact a compressor had on the whole hydrogen systems LCOH based on the results from this study might differ slightly from reality.

The sensitivity analysis regarding subsidies for constructing a new LRC storage showed how a project like this could benefit from economic funding. This was not an unexpected result, but nevertheless an important one. Subsidies would most likely make companies more prone to invest in HES which in turn could enable the hydrogen market to thrive.

7.4 Interpretation of LCOH

The hydrogen market today is characterized by a high degree of confidentiality where few actors share the cost of their products in public. Therefore, accessing price information regarding various components in a HES was challenging. This resulted in few first-hand sources, and many price estimations were therefore based on scientific reports and prognoses, not on actual prices obtained from hydrogen component manufacturing companies. Some data accessed through reports are one to three years old, and because the hydrogen market is changing rapidly some of these numbers could be considered outdated. To validate this data, it was compared with future prognoses and to information retrieved from the electrolyzer manufacturer company Nel Hydrogen.

Since the financial aspects of this study were centered around the results of the LCOH, it is important to interpret what the generated LCOH values actually entail. The LCOH represents the production cost of hydrogen and depending on the final selling price there can be different profitable outcomes. The lower CAPEX of the AEL compared to PEM is likely to change which implies that in a future scenario, a PEM system could result in a lower LCOH. But as of today, choosing a PEM system over AEL would lead to a loss in profit. However, future market opportunities for flexible hydrogen production such as entering the electricity balancing market could possibly compensate for this loss which would motivate the use of PEM financially.

The results showed that a larger demand always resulted in lower LCOH. For the independent refueling stations this was illustrated by higher demand cases resulting in lower LCOH but also by the refueling station located in Södertälje constantly getting lower LCOH than its counterpart in Sundsvall due to the differences in the traffic flow. This indicates that establishing independent refueling stations in heavily trafficked locations will be more profitable, not only due to more potential customers but also due to the margin between the production cost and the selling price given that the hydrogen is sold for the same price. This is an issue that comes from the fuel being produced at the site of the refueling station, introducing large investment costs, instead of being transported to the location of utilization. The lower electricity prices in e.g. Sundsvall compared to Södertälje did not even out these differences due to the investment costs affecting the LCOH more than the electricity price. The issue could be solved by setting higher prices in areas less trafficked, however such actions could potentially make the hydrogen transition something more affordable for densely populated areas. To avoid such scenarios federal subsidies could be a way of making hydrogen affordable independent of geographical locations.

The decrease of the LCOH by as much as 20 SEK per kg when the wind electricity was 0.2 SEK per kWh compared to 0.6 SEK per kWh shows how large an impact wind electricity prices have on the LCOH for a hydrogen production system utilizing electricity from wind farms. For the implementation of future systems, this shows the cost-related impacts of using wind power as an electricity source. With that said, a higher share of wind power in the energy system will likely make the prices converge towards each other, and the difference between using wind electricity or electricity from the grid might not have as large impact on the LCOH in the future. The predictions of electricity from offshore wind power decreasing will likely make a hydrogen production integrating wind power more financially competitive.

Even if a transition of e.g. the operations in Gävle Hamn from diesel to hydrogen does not generate economic profit, this could create other values such as branding the business as green and renewable. If fossil fuels would become more expensive in the future, this would also be an incentive for a hydrogen transition. Considering the green transformation of society and the increased interest in renewables, obtaining a higher reputation in the eyes of the public can possibly generate economic value.

7.5 Future Research

For future research it would be interesting to investigate how implementing a smart control system for hydrogen production could affect the LCOH and the utilization of wind electricity. This could for example be in terms of using a flexible threshold price, adapting to the storage level and seasonal variations, instead of having a fixed price for the whole year. A smart system could take factors such as weather forecasts, filling rates in the hydroelectricity dams, and planned maintenance in large electricity production facilities into consideration and adjust the hydrogen production according to these predictions. Such a system combined with a machine learning algorithm trained on historical data could also make it possible to predict future electricity prices. This would enable optimal regulation of the threshold price, further optimizing the system. Predicting electricity prices and weather conditions would also be of interest for regulating the storage level by telling the system when to increase or decrease the hydrogen production. Implementing a smart HES that could participate as a balancing actor on the electricity market would also enable predictions on when such services are needed. How the storage should be dimensioned optimally in such a case would also be an interesting field of future studies. If including a fuel cell in the system to enable power-to-power conversion to participate in the electricity balancing market, this would require different storage dimensions and potentially different storage configurations regarding pressure and construction technique.

8. Conclusions

Based on this study it can be concluded that the use of AEL for hydrogen production generates lower LCOH whereas PEM enables more flexible regulation and a higher share of wind electricity integrated in the system. The future predictions of price reductions of PEM, and other possibilities the technology entails such as participating in the electricity balancing market, makes PEM worth considering in projects. Regarding the regulation of hydrogen production using PEM, it should be based on a threshold price corresponding to the average electricity price with a base production securing constant access to hydrogen in the storage. Considering varying electricity prices over the year, the threshold price and base production should not be fixed values but adapt according to the momentary electricity prices.

Using vessels above ground and constructing a new LRC are the most financially preferable options for storing hydrogen in Gävle Hamn. Vessels are the most preferable storage solution for small-scale demand scenarios in terms of LCOH and constructing a new LRC is better suited for large-scale demand scenarios. However, a more thorough examination of the bedrock has to be made before ruling out the option of repurposing existing underground units for hydrogen storage.

The LCOH depends on a large variety of factors such as component costs, electricity prices, electricity sources, and demand scenarios. One thing that all cases have in common is a decrease in LCOH with increased system size. The difference in LCOH of approximately 20 SEK per kg hydrogen for different wind electricity prices in the Gävle Hamn case shows the impact the chosen electricity source has on the LCOH. For the refueling stations, the LCOH did not differ by as much but still, a lower electricity price resulted in the lowest LCOH.

It can be concluded that as of today, a hydrogen system including a large share of wind power cannot financially compete with a system using solely electricity from the grid financially, if only considering the LOCH. With that said, the future potential for a system utilizing wind power can be huge with a decrease in wind electricity prices. In such a scenario, hydrogen production using PEM electrolyzers might become more financially beneficial than using AEL. From a system view with offshore wind energy integrated with the hydrogen production, producing hydrogen instead of selling the electricity to the grid could be a profitable strategy.

This study is intended as a framework for future research in large-scale implementations of hydrogen energy systems. The costs regarding storage, electrolyzers, compressors etcetera would most likely differ in a real case scenario, which might influence which storage option and electrolyzer technology are most favorable from a financial and technical perspective. This study does however show interesting results regarding the potential for flexible hydrogen production integrated with offshore wind farms. These are results worth acknowledging considering the increased share of wind power in the energy system and the expected growth of the hydrogen market.

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Appendix

Assumptions for Operations in Gävle Hamn

Table A. Compilation of the number of trucks, the diesel consumption and the corresponding hydrogen consumption.

	Number of trucks per day	Average fuel consumption [l/day]	Average hydrogen demand [kg/day]	Total hydrogen demand [kg/day]
Weekday	202	230	50.72	10 245
Weekend	40	230	50.72	2028

Table B. Specific data of forklifts operating in Gävle Hamn based on consumption data of Kalmar and Linde forklifts. (Forkliftcenter B.V., n.d.a & b; Kalmar, 2016, 2017, 2019 a & b)

Lift capacity [tons]	Number of Forklifts (Yilport)	Number of forklifts (Sören Thyr)	Assumed fuel consumption per forklift [l/h]	Estimated hydrogen consumption per Forklift [kg/h]
2	3	1	3.2	0.78
3,5	2		3.6	0.88
4	2	1	4.6	1.13
4,5	1		4.8	1.18
5	7	2	5.0	1.23
8	14	3	7	1.72
15	11	2	9	2.21
16	1		9.5	2.33
30	1	1	14	3.43
33	1		15	3.68

Table C. Number of reachstackers, diesel fuel consumption and corresponding hydrogen consumption. (Kalmar, 2019a)

Number of reachstackers (Yilport)	Number of reachstackers (Sören Thyr)	Assumed fuel consumption per reach stacker [l/h]	Estimated hydrogen consumption per reach stacker [kg/h]
14	5	17	4.17

Table D. Specific data for wheel loaders operating in Gävle Hamn based on consumption data for CAT wheel loaders. (Wheeler Cat, 2018)

Number of wheel loaders (Yilport)	Number of wheel loaders (Sören Thyr)	Operating weight [kg]	Comparable CAT wheel loader model	Assumed fuel consumption per wheel loader [l/h]	Estimated hydrogen consumption per wheel loader [H2/h]
1		3394	907D	4.75	1.16
1	1	3747	907D	4.75	1.16
1		4100	907D	4.75	1.16
1		9400	914M	6.80	1.67
1		11800	920	6.80	1.67
1		13567	926M	6.85	1.68
1		15250	930M	7.15	1.75
3	2	19000	950M	11.35	2.78
1		21000	962M	12.20	2.99
1	1	28500	980M	20.70	5.07
1		31000	980M	20.70	5.07

Table E. Specific data for terminal tractors based on fuel consumption gathered from the report Studies for the LNG bunkering station for road transport and maritime transport in Luka Koper.

Number of terminal tractors (Yilport)	Number of terminal tractors (Sören Thyr)	Assumed average fuel consumption [l/h]	Estimated hydrogen consumption per terminal tractor [kg/h]
11	7	4.55	1.11

Table F. Possible compositions of machinery for different stages of hydrogen transition

Type of vehicle/machinery	Demand case 15%	Demand case 50%	Demand case 100%
Trucks	30	101	202
Forklifts (Lift capacity: 2 tons)	4	4	4
Forklifts (Lift capacity: 3,5 tons)	2	2	2
Forklifts (Lift capacity: 4 tons)	3	3	3
Forklifts (Lift capacity: 4.5 tons)	1	1	1
Forklifts (Lift capacity: 5 tons)	5	9	9
Forklifts (Lift capacity: 8 tons)	0	15	17
Forklifts (Lift capacity: 15 tons)	0	0	13
Forklifts (Lift capacity: 16 tons)	0	0	1
Forklifts (Lift capacity: 30 tons)	0	0	2
Forklifts (Lift capacity: 33 tons)	0	0	1
Reachstackers	3	9	19
Terminal tractor	3	9	18
Wheel loader (Operating weight: 3394-4100 kg)	4	4	4
Wheel loader (Operating weight: 9400-11800 kg)	1	2	2
Wheel loader (Operating weight: 13567 kg)	0	1	1
Wheel loader (Operating weight: 15250 kg)	0	1	1
Wheel loader (Operating weight: 19000 kg)	0	5	5
Wheel loader (Operating weight: 21000 kg)	0	0	1
Wheel loader (Operating weight: 28500 kg)	0	0	2
Wheel loader (Operating weight: 31000 kg)	0	0	1