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Green hydrogen production at Igelsta CHP plant

A techno-economic assessment conducted at Söderenergi AB

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Abstract

The energy transition taking place in various parts of the world will have many effects on the current energy systems as an increasing amount of intermittent power supply gets installed every year. In Sweden, just as many other countries, this will cause both challenges and opportunities for today´s energy producers. Challenges that may arise along with an increasingly fluctuating electricity production include both power deficits at certain times and regions but also hours of over-production which can cause electricity prices to drop significantly. Such challenges will have to be met by both dispatchable power generation and dynamic consumption. Conversely, actors prepared to adapt to the new climate by implementing new technologies or innovative business models could benefit from the transition towards a fully renewable energy system.

This thesis evaluates the techno-economic potential of green hydrogen production at a combined heat and power plant with the objective to provide decision support to a district heat and electricity producer in Sweden. It was in the company's interest to investigate how hydrogen production could help reduce the production cost of district heat as well as contribute to the reduction of greenhouse gases.

In the project, two separate business models: Power-to-gas and Power-to-power were evaluated on the basis of technical and economic performance and environmental impact. To do this, a mathematical model of the CHP plant and the hydrogen systems was developed in Python which optimizes the operation based on costs. The business models were then simulated for two different years with each year representing a distinctly different electricity market situation.

The main conclusions of the study show that Power-to-gas could already be profitable at a hydrogen retail price of 40 SEK per kg, which is the projected retail price for the transportation sector. The demand today is however limited but is expected to grow fast in the near future, especially within heavy transportation. Another limiting factor for hydrogen production showed to be the availability of storage space, as hydrogen gas even at pressures up to 200 bar require large volumes.

Power-to-power for frequency regulation was found to not be economically justifiable as the revenue for providing grid services could not outweigh the high investment costs for any of the simulated years. This resulted in a high levelized cost of energy at over 3000 SEK per MWh which was mostly due to the low capacity factor of the power-to-power system.

Finally, green hydrogen has the potential of replacing fossil fuels in sectors that is difficult to reach with electricity, for example long-haul road transport or the shipping industry. Therefore, green hydrogen production in large scale could help decarbonize many of society's fossil-heavy segments. By also serving as a grid-balancer, hydrogen production in a power-to-gas process has the potential of becoming an important part of a renewable energy system.

Keywords

Green hydrogen, Power-to-gas, renewable energy, mixed integer linear programming, Power-to-power, Combined heat and power, district heat

Sammanfattning

Energiomställningen som äger rum i olika delar av världen kommer att ha många effekter på de nuvarande energisystemen eftersom en ökande mängd väderberoende kraftproduktion installeras varje år. I Sverige, precis som många andra länder, kommer detta att medföra både utmaningar och möjligheter för dagens energiproducenter. Utmaningar som kan uppstå tillsammans med en alltmer fluktuerande elproduktion inkluderar både kraftunderskott vid vissa tider och regioner men också timmar av överproduktion som kan få elpriserna att sjunka avsevärt. Sådana utmaningar måste mötas av både planerbar kraftproduktion och dynamisk konsumtion. Omvänt kan aktörer som är beredda att anpassa sig till det nya klimatet genom att implementera ny teknik eller innovativa affärsmodeller dra nytta av övergången till ett helt förnybart energisystem.

Denna rapport utvärderar den tekno-ekonomiska potentialen för produktion av grön vätgas vid ett kraftvärmeverk med målet att ge beslutsstöd till en fjärrvärme- och elproducent i Sverige. Det var i företagets intresse att undersöka hur vätgasproduktion kan bidra till att sänka produktionskostnaden för fjärrvärme samt bidra till att minska växthusgaser.

I projektet utvärderades två separata affärsmodeller: Power-to-gas och Power-to-power baserat på teknisk och ekonomisk prestanda samt miljöpåverkan. För att kunna göra detta utvecklades en matematisk modell i Python av kraftvärmeverket och vätgassystemen som optimerar driften baserat på kostnader. Affärsmodellerna simulerades sedan för två olika års elpriser för att undersöka modellens prestanda i olika typer av elmarknader.

De viktigaste slutsatserna i studien visar att Power-to-gas redan kan vara lönsamt till ett vätgaspris på 40 SEK per kg, vilket är det förväntade marknadspriset på grön vätgas for transportsektorn. Efterfrågan är idag begränsad men förväntas växa snabbt inom en snar framtid, särskilt inom tung transport. En annan begränsande faktor för vätgasproduktion visade sig vara tillgången på lagringsutrymme, eftersom vätgas även vid tryck upp till 200 bar kräver stora volymer.

Power-to-power för frekvensreglering visade sig inte vara ekonomiskt försvarbart, eftersom intäkterna för att tillhandahålla nättjänster inte kunde uppväga de höga investeringskostnaderna under några av de simulerade åren. Detta resulterade i en hög LCOE på över 3000 SEK per MWh, vilket främst berodde på Power-to-power-systemets låga utnyttjandegrad.

Slutligen kan det sägas att grön vätgas har stor potential att ersätta fossila bränslen i sektorer som är svåra att elektrifiera, exempelvis tunga vägtransporter eller sjöfart. Därför kan storskalig grön vätgasproduktion hjälpa till att dekarbonisera många av samhällets fossiltunga segment. Genom att dessutom fungera som balansering har väteproduktion i en Power-to-gas-process potential att bli en viktig del av ett system med stor andel förnybar energi.

Keywords

Grön vätgas, Power-to-gas, förnybar energy, mixed integer linear programming, Power-to-power, kraftvärme, fjärrvärme

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Abbreviations

CHP – Combined heat and power

DH – District heating

IKV – Igelska Kraftvärmeverk

PtG – Power-to-gas

PtP – Power-to-power

HHV – Higher heating value

CAPEX – Capital expenditures

OPEX – Operational expenditures

LHV – Lower heating value

LCOH – Levelized cost of hydrogen

LCOE – Levelized cost of energy

NPV – Net present value

GHG – Greenhouse gas

CO_2 – Carbon dioxide

1 Introduction

This section introduces the background, objective and research methodology of the project.

1.1 Project background

The Swedish energy system is in a phase of transition where conventional technologies of supplying energy, such as fossil fuels or nuclear power are being replaced by intermittent renewable energy sources at an increasing rate. Along with a growing demand of power due to the electrification of historically fossil fuel-dominated sectors, these changes are causing a number of challenges that need to be faced in the coming years. These challenges will not only require new technologies and solutions to specific problems but also a system perspective where new solutions are seen integrated parts of a larger context. For actors who are able to apply this way of thinking into practice, challenges can become opportunities.

One of the possible solutions to many energy-related problems is the use of renewable hydrogen, also known as green hydrogen. The technology related to green hydrogen has gained much momentum in recent years as it has been recognized for its versatile and sustainable use as energy carrier and storage of renewable electricity, emission-free fuel for transportation and industry as well as feedstock is some of the world's most common chemicals. Due to its cross-sectorial span of applications, hydrogen is today viewed as a promising key part in the decarbonisation in some of the most fossil-heavy sectors.

This project has been carried out in collaboration with Söderenergi, a district heat and electricity producer located in Södertälje, Sweden. Söderenergi has in previous research identified trends in the electricity market, where spot prices are becoming increasingly volatile due to changes in the Swedish power system. One result of this development is that combined heat and power (CHP) plants, which use the revenues from sold electricity to decrease the production cost of heat, are becoming increasingly more expensive to operate. This could result in raised heat prices for district heat consumers or in the long-run, non-renewed investments in CHP plants. In the latter case, the power system would lose the important contribution of dispatchable power generation that CHP plants provide. These changes could require new business models in order to not be forced to raise the price for the district heat consumers. One alternative that has been identified is to use the electricity during the low-price hours to produce hydrogen in an electrolysis process, also known as power-to-gas. This concept could have the potential to increase the operational flexibility of the CHP plant while keeping the district heat price low.

The aim of the thesis is to evaluate how hydrogen production could be integrated in Söderenergi's CHP plant *Igelsta Kraftvärmeverk* (IKV) in order to find alternative and better ways of using the electricity during low-price hours. The study will also present a techno-economic assessment of how hydrogen production would affect the performance of the plant as well as the economic and logistical considerations that this would imply.

1.2 Objective

The objective of this thesis is to assess the techno-economic aspects of producing hydrogen gas by electrolysis at Söderenergi's IKV and to evaluate the cost-efficiency of the concept under current and future conditions. The assessment will serve as decision support for Söderenergi to assist their ambition to reduce the district heat price in a changing electricity market along with the aim of providing sustainable energy to its customers.

To obtain the objective, an understanding need to be gained of the dynamics of the district heating sector, electricity market and Söderenergi's role in connecting these sectors. Thereafter, knowledge of the power-to-gas concept and the hydrogen market will be gathered in order to find potential ways of integrating it into Söderenergi's operation. This data and knowledge will then be used to develop scenarios of future modes of operation with variation in prices and technical conditions. Lastly, a techno-economic model will be developed in order to simulate and evaluate the performance of the proposed scenarios.

To satisfy the objective, the following questions will be answered:

- What technical aspects are of relevance for IKV to apply the power-to-gas concept?
- Which markets are relevant for the produced hydrogen and how are they projected to develop in the near future?
- What business models could be applied and how would these perform in different scenarios?
- What logistical aspects are important for Söderenergi regarding the storage and distribution of hydrogen?
- What environmental impact could hydrogen production have on Söderenergi's CO_2-footprint?

1.3 Research methodology

The overall methodology of this thesis will be divided into three main parts. The first one will be a literature study that will cover written information about the current Swedish energy system in which Söderenergi is an actor. Here, information about the technical and regulatory parts of the electricity and district heating markets will be gathered along with projected trends and future policies. Also, the literature from earlier studies of power-to-gas concepts will be reviewed in order to learn from past experiences and identify certain aspects relevant to Söderenergi.

The second part of the project will consist of an interview study, where semi-structured interviews with actors with relevant people who hold specific information and knowledge within the fields of electricity market, district heating and hydrogen technology. This will be done to gain an understanding of the mechanisms that affect the trends within these fields and to relate the insights to the information found in the literature.

Lastly, the information found in the literature and the interview studies will be used to develop various scenarios that will reflect certain trends in the electricity market and hydrogen technology development. The scenarios will then be analysed using a mathematical model that will show the economic feasibility of applying hydrogen production at IKV. Based on the outcomes of the economical calculations as well as the environmental aspects, this thesis will provide recommendations of which areas that could be of interest to Söderenergi to keep investigating.

1.4 Delimitations

This study is limited to hydrogen production through electrolysis although it is recognized that there are other methods available. For re-electrification of hydrogen, only fuel cells were investigated as an alternative even though this could be achieved with for example gas turbines. The limitation was drawn as the aim was to get a general overview of the potential of hydrogen production at IKV. More comparative studies could be done based on the results from this thesis. Another physical limitation was that the project was carried out in a purely Swedish context, analysing only the Swedish hydrogen market and power system. In the future, it is likely that a product like green hydrogen will be traded internationally so to get a more solid market study, the limitations could be extended to the EU region.

The techno-economic modelling also introduces some simplifications that could have effects on the results. These were done due to lack of appropriate data or to simplify the process. Examples of such simplifications are component efficiencies, which are modelled as constant even though load-dependent performance is common. The model was however developed to get an understanding of how hydrogen-based systems perform in different scenarios and not to deliver exact results, something that is left for future studies.

2 Theoretical background

This section provides the theoretical background of the Swedish energy system and introduces Söderenergi's role in it.

2.1 The Swedish energy system

The Swedish power system is currently dominated by two major stable power sources, with hydropower and nuclear power each providing 40% of the total generated electricity. These have been the core and the main body of the power system for over 40 years, when it was built in order to accommodate the power intense industry expansion that took place in that time (Energiföretagen, 2021a). Since then, the system has been relying on hydro and nuclear power along with a substantial amount of cogeneration from combined heat and power (CHP) plants for stability and balance within the network. This has provided Sweden with a reliable base load for many years and contributed to Sweden's power systems low carbon footprint, which is fossil-free to about 98% (Sköldberg, Unger and Holmström, 2015; Energiföretagen, 2021a).

2.2 A power system in transition

However, as many other countries around the world, the energy system in Sweden is facing large changes as it moves towards becoming renewable, following the Paris Agreement accord and aims to be carbon neutral by 2045 (Regeringskansliet, 2018). One major shift that has already started is the rapid increase of wind power capacity.

The other large transition that is currently happening is the growing share of installed wind power. It has gone from being an insignificant part of the energy system in the early 2000's to constitute over 22% of the installed capacity in 2020 as well as producing 28 TWh, which was 17% of the total electricity (Energiföretagen, 2021c). This is partly due to the electricity certificate system that was implemented in 2003 with the purpose of increasing the share of renewable power with end-date of year 2035. The certificates are distributed to renewable electricity generating companies which in turn sell them to companies like electricity suppliers and power intense industries that are subject to quota. Since the system is market-based, the more renewable energy that gets integrated, the more the prices of the certificates drop. This has during the last years made the system of electricity certificates less effective (ibid). Nevertheless, the incentive helped wind power to gain a momentum that today makes it fully competitive on its own, due to falling capital costs and significant performance development (Energimyndigheten, 2019). Wind power is projected to keep expanding in Sweden the coming years, growing to over 82 TWh by 2040 which would be over 40% of the total generation. (Svenska Kraftnät, 2018)

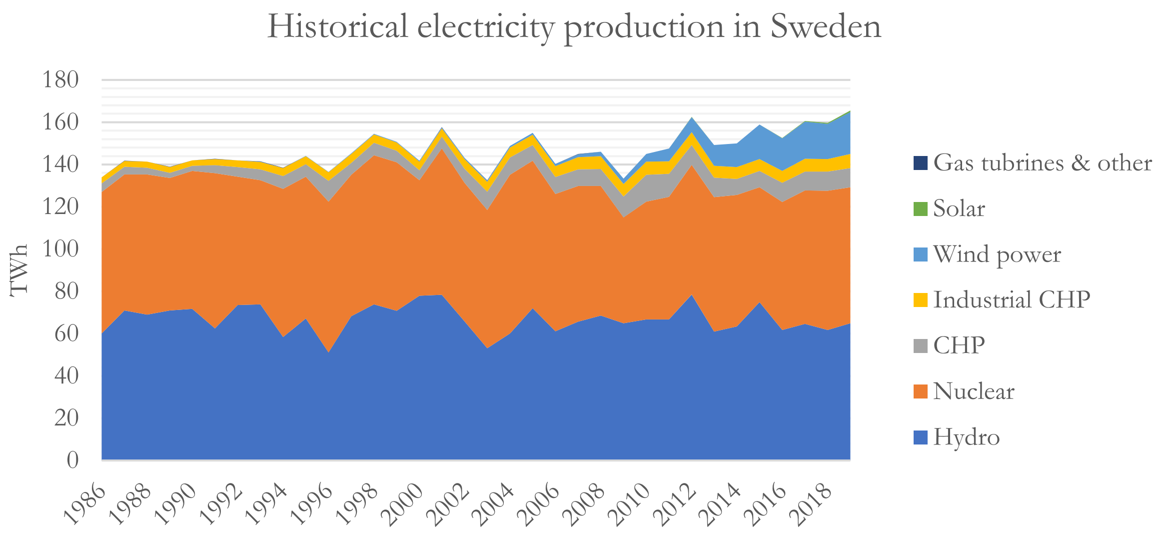

Figure 1 - Power generation by source (SCB, 2020)

As the capacity share of wind power keeps expanding, the variability in the electricity production increases. This is a result of wind power being a weather dependent source of generation. The development has a number of effects on the power system, of which increased price volatility has been identified by SVK (2018) as a clear trend. This is an effect of weather conditions having an increasingly larger impact on the electricity prices. During hours with strong winds for example, large amounts of power will be injected into the electricity grid, causing the prices to drop to low levels. Similarly, for hours when the wind power plants produce small amounts of power, the decrease of supply causes the prices to increase proportionally to the power deficit.

2.2.1 Balancing of the power system

In Sweden, Svenska Kraftnät (SVK) is in charge of keeping the power system in balance. That means that they are responsible to match consumption and production at all times, making sure that the frequency is stable at 50 Hz (Power Circle, 2019). If for example the power production decreases while the consumption stays the same, the frequency will drop and cause damage to the system. In this case, there is a need of rapidly increase production to restore the frequency, also called up-regulating. Alternatively, if the power consumption would suddenly drop while production remains unchanged, the frequency increases. In this case, down-regulating through decreased production or increased consumption is required. (ibid)

To maintain the frequency at 50 Hz, SVK operates four balance markets constituting of automatic reserves and manual measures. The first two are so called frequency containment reserves (NCR) and are the fastest responding power reserves. They are made up rotating mass and are automatically activated within seconds when imbalance is detected. The other two markets are also known as frequency restoration reserves (FRR) and have the aim of restoring the frequency within up to 15 minutes after disturbance. These are manged though bids for up- or down regulation of power. (Svenska Kraftnät, 2020)

The reserves included in the manual frequency restoration reserve (mFRR) are traded on an own market called the regulatory power market (RPM) where bids on up or down regulating power can be made up to 45 minutes before the operating period starts with the requirement that they are able to activate within 15 minutes. In Sweden, the minimum bid is today 10 MW but there are plans to lower this to 1 MW (Svenska Kraftnät, 2020) (Power Circle, 2019).

2.3 District heating

District heating (DH) can be described as a system consisting of centralized heat producing facilities, distribution networks and heat consumers. It has played an important role in the Swedish energy system for many decades and has been expanded continuously since it was established in 1960. In 2014, 55% of all heat demand for buildings were supplied with DH (Werner, 2017) . Since the expansion of DH networks, the fuel input has varied greatly. In its early years, the heat was almost exclusively produced from fossil fuels and dominated by oil-fuelled boilers and CHP:s. However, the oil-crisis in the 1980's, started a large shift towards replacing oil with biomass, electricity and municipal solid waste. Since then, large efforts have also been made to recover waste heat from industries as well as integrating heat pumps, which utilize low-grade ambient heat along with electricity (Werner, 2017). This development has resulted in a continuous decline of fossil CO_2-emissions and has been a key role in decarbonising the Swedish heating sector (Sköldberg, Unger and Holmström, 2015).

The DH network in the Stockholm region is one of the largest in the world, producing 9 TWh of heat annually and represents 20% of Sweden's total DH supply. It consists of over 50 heat producing facilities which are connected by pipes that connect them to the consumers. The system is operated by three main actors: Stockholm Exergi, Norrenergi and Söderenergi (Söderenergi, 2020b). Each actor owns and operates its own facilities but shares the DH network with the overall objective to deliver heat to its customers at the lowest possible price. How the system operates from hour to hour requires close collaboration between the companies and is determined by production planning.

The principle of production planning is to in advance schedule the operation of the facilities in the network. This is done by first creating a predicted heat load profile over the coming days which is mostly influenced by the weather forecast, as the outdoor temperature and heat load are closely connected (Dotzauer, Gollvik and Andersson, 2007). Based on the predicted load, the heat production is then allocated to the various facilities on a merit order scale where the facilities with the lowest production costs of one unit of heat are placed first. The production costs are primarily a function of fuel prices, operation and maintenance costs and taxation. However, facilities that produce both heat and electricity, use the revenue for the sold electricity to lower the production cost, placing such plants generally early in the merit order. (ibid)

2.4 Söderenergi

Söderenergi AB is as mentioned one of the main DH producers in the Stockholm region and is owned by the municipalities of Södertälje, Huddinge and Botkyrka. The company owns several heat-only facilities and one CPH plant, which together supply over 300 000 people, offices and industries in the Stockholm region. Additionally, Söderenergi produces electricity equivalent to 100 000 households' consumption. The annual production reaches approximately 2500 GWh of district heat and 550 GWh of electricity. (Söderenergi, 2020b)

2.5 Igelsta CHP plant

IKV is a CHP plant located in Södertälje. It was commissioned in 2009 and is currently the second largest bio-fuelled CHP plant in Sweden (Söderenergi, 2020a) .The working principle of a CHP plant is to produce electricity while utilizing heat generated by the process. By producing both power and heat, more energy can be extracted by the fuel which allows for a high degree of overall efficiency. This does however require a demand for heat. In Sweden, where DH networks are common, CHP plants play an important role of providing dispatchable power and heat with high total efficiency of typically 90%. (Royal Swedish Academy of Engineering Sciences, 2016)

The boiler in IKV is of the type circulating fluidized bed which is fed by fuel consisting mainly of biofuels (90%), of which 60% is forest residues and 30% recycled wood waste. The remaining 10% comes from solid recovered fuels, which is typically solid waste that is unfit for material recycling. In total, the plant consumes 600 000 tonnes of fuel per year. By using a circulating fluidized bed with sand bed of 850 °C, the high combustion temperature and thermal inertia of the chamber causes a fast evaporation of moisture in the fuel. The thermal energy in the vapor is utilized in a flue gas chamber. This gives IKV the opportunity to efficiently combust fuels with high moisture content. (Söderenergi, 2010)

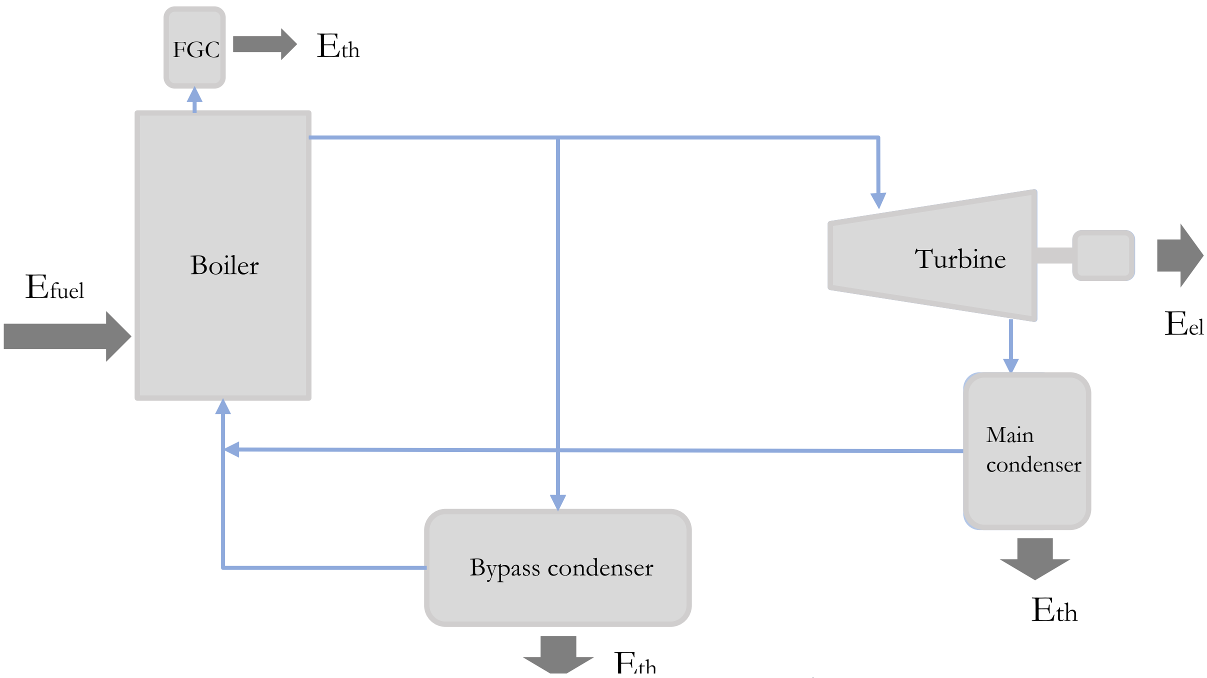

Figure 2 - Schematic of Igelsta Combined heat and power plant. The blue lines represent the water/steam flow and the gray pointers show the energy in and output.

Power is generated in a 85 MW steam turbine, which expands superheated steam at 540 °C and 90 bar. The saturated steam is then lead into a condenser where it is used to heat up district heating water with a thermal capacity of 154 MW. This mode of operation is called back-pressure mode (BP). Additionally, the mentioned flue gas condenser can extract up to 57 MW of heat. If needed, IKV can switch to direct condensing mode (DC), meaning that the steam is led to bypass the turbine and fed directly into a condenser with a thermal capacity of 240 MW. The plant is operating 6 200 hours annually and produces about 1 400 GWh heat and 550 GWh electricity. (Söderenergi, 2010)

Even though IKV produce large amounts of electricity, the primary objective is to produce district heat at the lowest possible price. The revenues from the sold electricity are therefore used to lower the production cost of the heat. For this reason, BP-mode is the most common operational mode while DC is applied when the heat load is particularly high, or the electricity price is very low. The mode in which IKV operates is determined by an optimizing algorithm with the objective to minimize the production costs for district heat. (Mizgalewicz and Karkulahti, 2020)

3 Hydrogen

This section introduces several hydrogen technologies and their related costs. It also discusses future projection of costs as well as the development of hydrogen markets in Sweden.

3.1 An emerging technology

Hydrogen is generally classified into three main categories: Gray, blue and green, each specifying the origin and the process of producing it. *Gray hydrogen* is derived from natural gas and water via a process called steam-methane reforming (SMR) (Fossilfritt Sverige, 2021). Large amounts of CO_2 are generated in the process when carbon from methane reacts with oxygen. *Blue hydrogen* undergoes basically the same process but with the addition of carbon capture and storage (CCS) that reduces the carbon dioxide emissions by up to 80-90%. Even though the greenhouse gas emissions are relatively low, it is still considered a fossil product. *Green hydrogen* refers to hydrogen produced from renewable sources and is thus carbon neutral (IRENA, 2019b). Mainly, green hydrogen is a product of electrolysis, a process often referred to as power-to-gas, where renewable electricity produces hydrogen and oxygen by splitting water. Green hydrogen only constitutes around 1% of the global production today, making it a minor contributor to the energy system in total (Bloomberg New Energy Finance, 2020). This however is changing quickly as many important actors around the world has highlighted green hydrogen's potential for decarbonising the energy economy (Walker *et al.*, 2016).

Hydrogen has lately been subject to an increasing attention on a global level after being identified as a key part of the necessary energy system transition that is bound to happen in the coming 30 years in order to slow down climate change (European Commission, 2020). Due to its versatile use as carrier and storage for dispatchable renewable energy as well as fuel and feedstock in industrial processes, it spans many different applications and is thus able to couple different sectors with the objective of decarbonisation. Even though renewable electricity has made significant progress in reducing CO_2-emissions, there are fossil-heavy sectors where the need of high-density energy, seasonal energy storage or certain industrial processes that makes electricity a non-viable option. For these applications, where decarbonisation is difficult to achieve but still critical, hydrogen could play a vital role for substituting fossil fuels. (Bloomberg New Energy Finance, 2020)

The interest of hydrogen technology has peaked a number of times in the past and failed to live up to the expectations. Today however, there are many indicators that imply that large-scale expansion is close. One important aspect is the broad, cross-sectorial spectrum of actors, such as renewable energy producers, industrial gas suppliers, oil and gas companies and some of the world's most influential governments. The interests of mentioned actors are not uniform and spans from carbon emission abatement to energy security to purely financial motives (IEA, 2019). This coalition of interests does not only imply mandate for action, but also massive financial incentives to drive the development forward. One example of this is the recently launched EU-project *Hydrogen strategy for a climate-neutral Europe* where hydrogen is classified as a key priority for the European Green Deal. The investment fund that accompanies the hydrogen incentive amounts to 430 billion Euro, which emphasises the scale of the project (European Commission, 2020).

3.2 Fundamentals of electrolyzing

Electrolysis is the process in which water molecules are separated into its fundamental elements of hydrogen and oxygen by oxidation-reduction reactions. The overall reaction equation is:

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

The splitting of water molecules is a non-spontaneous reaction and therefore needs additional electrical energy to happen. An electrolyser cell is made up by two electrodes (an anode and a cathode) which are supplied with DC power, an electrolyte which is the surrounding environment in which the reactions are taking place and a separating membrane. The electrolyte functions as a conductor for the electrical current by carrying either negatively or positively charged ions between the two electrodes. In order to create a voltage difference that drives the process, the electrolyte must be acidic (carrying positively charged ions) or alkaline (carrying negatively charged ions). (Götz *et al.*, 2016)

An electrolyser is assembled by stacking cells in a configuration called stack. The stack can be designed either by connecting the cells in series (monopolar) or in parallel (bipolar). Bipolar stacks have the advantage of reducing the voltage drop across the stack and thus increasing the potential efficiency (Bailera, M., Lisbona Martín, M.P., Peña, B., Romeo, 2020).

There are today three main types of electrolysing technologies: Alkaline electrolysis (AEL), Polymeric electrolyte membranes (PEM) and Solid oxide electrolyser cell (SOEC) . The difference between these is mainly which electrolyte is being used and thus which chemical reactions occurring at the electrodes (Götz *et al.*, 2016). Their physical characteristics are presented in table 1.

3.3 Alkaline electrolysis (AEL)

Alkaline electrolysis is today the most technologically mature and a widely applied method for large-scale production of hydrogen. It has been used for MW-scale production for over 100 years (Buttler and Spliethoff, 2018). The principal technology can be said to be relatively simple, consisting as displayed in figure 3 of two electrodes surrounded by liquid electrolyte solution of usually 70-75% water and 25-30% NaOH or KOH. The anode and cathode regions are separated by a thin membrane that keeps the produced gases from mixing but allows the ions to pass through on their way from the anode to the cathode. In alkaline electrolysis, the two half-reactions occurring are:

$$2H_2O + 2e^- \rightarrow H_2 + 2OH^- \ (At\ cathode) \tag{2}$$

$$2OH^- \rightarrow \frac{1}{2}O_2 + H_2O + 2e^- \ (At\ anode) \tag{3}$$

The formed gases of hydrogen and oxygen then bubble up from the electrolyte and are each passed through a gas-liquid separator from which the electrolyte is circulated back, and the product gases are dried and stored for further use. (Bailera, M., Lisbona Martín, M.P., Peña, B., Romeo, 2020)

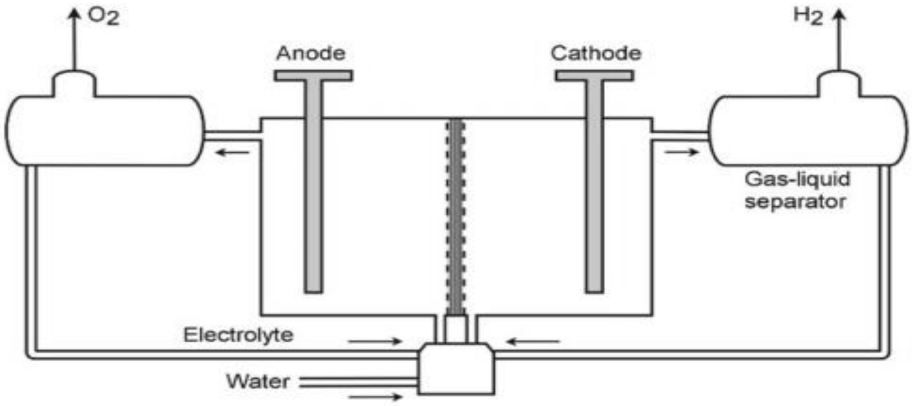

Figure 3 - Schematic of an AEL cell (Bailera, M., Lisbona Martín, M.P., Peña, B., Romeo, 2020)

Operational conditions of alkaline electrolysers often span from 40-90 °C and 1-60 bar and the LVH-based efficiency ranges from 62-71%. (Bailera, M., Lisbona Martín, M.P., Peña, B., Romeo, 2020). An AEL can operate at a load of 20-100% of its rated power. The minimum load requirement at 20% comes from the fact that the thin membrane that separates the electrodes is made of a porous material that lets a small amount of the product gases through. Due to the law of diffusion, as the current density at the electrode decreases, the concentration of the respective gases at the opposite side of the membrane increases. This does not only impurify the product gases but does also cause a safety risk. (Godula-Jopek, 2015)

The fact that the electrolyser should be turned off when operating at less than 20-25% load, along with a start-up time of 30-60 minutes makes the technology suboptimal for integration with highly fluctuating energy inputs. (Ulleberg, Nakken and Eté, 2010) Another disadvantage of the AEL is that the corrosiveness of the electrolyte easily cause damage on the material which leads to high maintenance costs. Despite that, an expected lifetime of an AEL is high compared to other electrolysing technologies, often reaching up to 30 years (Götz *et al.*, 2016).

3.4 PEM electrolysis

The PEM electrolyser, also known as Proton Exchange Membrane, is a significantly newer technology than AEL and has been in commercial use since 1978. (Götz *et al.*, 2016). As the name refers to, this type of electrolyser utilizes the exchange of protons through a proton-conductive solid polymeric membrane to form hydrogen and oxygen. In a PEM cell, the membrane is the core component and serves two functions: carrying protons (H^+) and separating the product gases. The anode and cathode are mounted directly on the membrane and encapsulated between two ribbed bipolar plates, as shown in figure 4. Water is led through the grooves on the plates to the anode region, where it reacts according to equation 4 and forms oxygen and protons. When the protons reach the cathode side, they form hydrogen gas according to equation 5 which is lead out through the opposite side's grooves and collected for gas treatment. (Bailera, M., Lisbona Martín, M.P., Peña, B., Romeo, 2020)

$$H_2O \rightarrow \frac{1}{2}O_2 + 2H^+ + 2e^- \; (At\ anode) \tag{4}$$

$$2H^+ + 2e^- \rightarrow H_2 \; (At\ cathode) \tag{5}$$

PEM is along with AEL considered a low-temperature electrolysis, with operating temperatures of 50-100 °C. The robust structure of the solid electrolyte makes for a very compact design compared to AEL and allows for high operational pressures that ranges from 0 to 100 bar. The membrane in a PEM cell allows for less cross-permeation of gases than AEL which makes it operational with a minimum load at almost 0% and also provides a higher gas purity, often higher than 99.99% H_2 after the drying process. (Götz *et al.*, 2016)

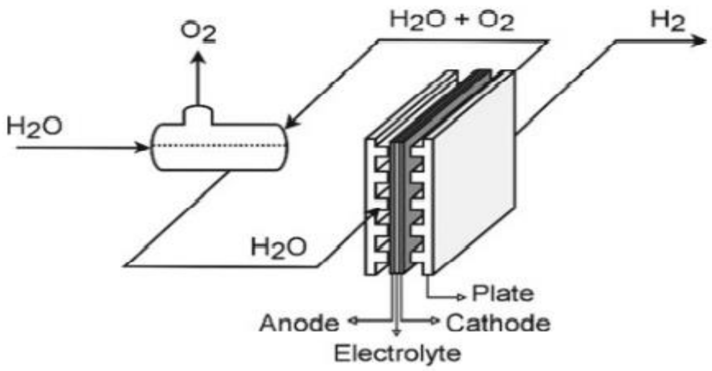

Figure 4 - Schematic of a PEM cell (Bailera, M., Lisbona Martín, M.P., Peña, B., Romeo, 2020)

The investment cost of PEM electrolysers is higher than the one of AELs, much due to the expensive polymeric membrane and the noble metals that are required in the electrodes in order to avoid corrosion. PEM does however hold a significant advantage over AEL when coupled with fluctuating electrical power. First of all, it has a fast ramp time of less than 10 seconds from a 0% load on stan-by mode to 100% on MW-scale. The cold start-up time is longer; up to 5-10 minutes. This is still considerably lower than the AEL's cold start-up time, which can be op to one hour. (Götz *et al.*, 2016)

PEM electrolysers can also operate between 0 to 100% of its rated power, which makes them suitable for intermittent power supply. The fact that PEM electrolysers do not have to recirculate large volumes of electrolyte during operation and their ability to handle high electrical currents make them compact and also suitable for fast response fluctuations in power. (Maric and Yu, 2018)

It has been identified as a key technology for coupling power-to-gas systems with renewable energy sources with variable power output, such as wind and solar power plants. Due to its fast response to transient variations in power, it has also been tested and qualified for frequency regulation in the grid. With abilities to provide both energy storage for intermittent power as well as supplying grid balancing services, PEM electrolysers can be applied for many types of business models which broadens its scope. (Bailera, M., Lisbona Martín, M.P., Peña, B., Romeo, 2020)

3.5 Solid oxide electrolysis (SOEL)

Solid oxide electrolysis is a recently developed technology that has a limited amount of commercially available electrolysers. It is also referred to as high temperature electrolysis, due to the high operational temperature. The working principle of SOEL are two half reactions shown in equations 6 and 7, where hot steam reacts on the cathode side to form hydrogen and oxygen ions. The ions are lead through a ceramic membrane and forms oxygen gas at the anode. SOEL resembles PEM cells in the physical setup of the cells, with two electrodes mounted on a solid conductive membrane shown in figure 5. The main difference is that it is supplied with hot steam instead of liquid water. This reduces the electrical consumption significantly compared to a low-temperature electrolysis. (Bailera, M., Lisbona Martín, M.P., Peña, B., Romeo, 2020)

$$H_2O \ + \ 2e^- \rightarrow H_2 + O^{2+} \ (At\ Cathode) \tag{6}$$

$$O^{2-} \rightarrow \frac{1}{2} O_2 + 2e^- \ (At\ Anode) \tag{7}$$

Although the development level of SOEL is still at laboratory stage, it has gotten a lot of interest for its high potential overall efficiency if the heat supply can be met by waste heat and could go as high as 90%. However, due to the high required operational temperatures, which ranges from 600 to 1000 °C, the electrolyser has a long start-up time and slow ramping capacity. This makes it unfit for intermittent fluctuating power supplies. (Bailera, M., Lisbona Martín, M.P., Peña, B., Romeo, 2020)

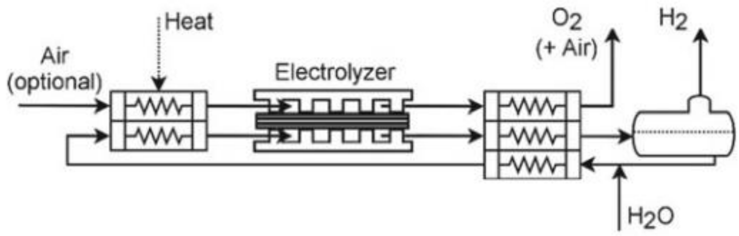

Figure 5 - Schematic of a SOEL cell (Bailera, M., Lisbona Martín, M.P., Peña, B., Romeo, 2020)

Table 1: Technical parameters of electrolysis technologies. Data collected from (Buttler and Spliethoff, 2018) *an * indicates that the data has been collected* (Götz *et al.*, 2016)

Technology	AEL	PEM electrolyser	SOEL
Maturity	Commercial	Commercial	R&D
Operating temperature (°C)	60 - 90	50 - 80	700 - 900
Operating pressure (bar)	10 - 30	20 - 50	1 – 15
Current density (A/cm^2)	0.25 – 0.45	1.0 – 2.0	0.3 – 1.0
Load flexibility of nominal capacity (%)	20 - 100	0 - 100	50 - 120
Transient operation*	Possible, but not recommended due to technical problems*	Proven fast response to dynamic changes	Not well suited
Warm start-up time	1 - 5 min	<10 s	15 min
Cold start-up time	1 - 2 h	5 - 10 min	>1 hour
Power consumption ($kWh_{el}/m_n^3{}_{H2}$)	5.0 - 5.9	5.0 - 6.5	3
Lifetime (years)	20	20	unknown
Space requirements (m^2/kW)	0.1	0.05	unknown

3.6 Fuel cells

In cases where hydrogen is used as energy storage for electrical system, a common method of converting the hydrogen back to electricity is the use of fuel cells. The working principle of a fuel cell is essentially a reversed electrolysis process, constituted of an anode, cathode and a surrounding electrolyte. By feeding hydrogen to the anode, the hydrogen molecules are split into electrons and protons. The protons travel through the electrolyte and reacts with oxygen to form water while the electrons are led out to create electrical current (U.S. Dept of energy, 2015) .Therefore, the only by-product of producing electricity in a fuel cell is water which makes it an emission free method of power generation. The most common fuel cell technologies available are PEM, alkaline and solid oxide, each working by the reverse principle as its corresponding electrolysis technology (ibid).

Fuel cells have been proved to be a feasible solution for many different applications of which back-up power and vehicle services are the most common. A growing interest in fuel cells as providers of gird services have recognized by Alshehri *et al.* (2019), where fuel cells take part in the frequency control market. By producing hydrogen when the price of electricity is low and storing it for high-price hours a business model based on energy arbitrage can generate profit. Such systems are often referred to as power-to-power (Weidner *et al.*, 2018).

PEM fuel cells have seen a particularly fast growth of interest in recent years, much due to its fast response time and flexible range of operation. As with electrolysers, they are available in MW-sizes and are often modular in order to easily scale up the capacity. Its high power density also gives it a compact design compared to other fuel cell technologies. The electrical efficiency of most fuel cell is in the range of 40-60%, where the rest is turned into heat. (Alshehri *et al.*, 2019)

3.7 Storage

In order to make use of hydrogen as a flexible and cross-sectional energy carrier, a well-functioning storage system is critical. Since hydrogen does not deteriorate over time, it has the potential of providing long-term storage opportunities. However, although hydrogen gas is energy dense when measured in energy per weight, the volumetric density is low compared to the fossil fuels that hydrogen is targeted to replace. Put in context, one kilogram of hydrogen gas at 25 °C. and atmospheric pressure occupies over 11 m^3 (Andersson and Grönkvist, 2019). This means that in order use hydrogen as an energy carrier in a practical and economically viable way, there is a need of substantially decreasing the volumetric density for storage and transportation purposes. All of the available methods require additional resources such as energy or hydrogen-binding materials, which adds costs and complexity to the overall system. There is no single answer to which storage option is best fitted for hydrogen systems, as it is heavily dependent on both the technical circumstances in which the plant is operating and the end-use of the produced hydrogen. (ibid)

Today, hydrogen can be stored using several technologies which are usually classified into three main principles:

- Physical storage in its pure molecular form
  - Pressurized gas: H_2 (g)
  - Liquification: H_2 (l)
- Chemical storage (absorption) by bonding to:
  - Carbon (to form hydrocarbons)
  - Nitrogen (to form ammonia)
- Adsorption into other materials

Physical storage

Of all storage options, the use of pressurized tanks is today the most common one. It has the advantage of being flexible in the sense that it can easily be scaled up or down in size to meet the required storage demand and can be transported on conventional vehicles like trucks, trains and ships. Another advantage of pressurized tanks is the maturity of the necessary infrastructure and distribution networks as it has been used in the industry for a long time (Jackson *et al.*, 2020). Compared to other storage options, it also has a low investment cost (Wallmark and Mohseni, 2014). The most common pressure levels of hydrogen gas are low-pressure vessels at 30-80 bar and high pressure-vessels at 200-300 bar. Naturally, low-pressure storing requires less compression energy and lower material costs which makes it the cheapest option. They do however occupy large volumes which make them unfit where space is limited. High-pressure tanks are therefore often a more viable option for applications where the storage area is limited and transportation is required. (ibid).

Another way to store hydrogen gas is by using underground caverns, similar those for compressed air energy storage (CAES) applications. For this purpose, salt cavities have been identified as most promising. These have proven to be a reliable form of storage with low leakage, minimal gas contamination as well as fast injection and withdrawal. Also, salt cavities require a significantly lower investment cost compared to above-ground storage vessels due their large volumes, low construction and operational costs. However, suitable underground caverns are limited to a few geographical locations which makes them a seldom feasible option. (Andersson and Grönkvist, 2019)

The storage of liquidized hydrogen is just as pressurised gas a well-established technology but mainly for niche areas, such as space applications. It has the significant advantage that it does not need high pressure to attain a very high density. At atmospheric conditions, liquid hydrogen has the density of 70 kg/m^3. This is to be compared to hydrogen gas at 700 bar, which has a density at 39 kg/m^3 (Andersson and Grönkvist, 2019). However, this method is expensive due to high capital costs of the plant and the very energy intense process of liquefaction where the gas is condensed at – 253 °C. Another concern regarding this method is the evaporative losses that occur when heat is transferred from the surrounding environment to the stored hydrogen. The boiled off gas does not only represent a loss of energy but does also constitute a safety risk (ibid).

Adsorption

Adsorption storage of hydrogen uses materials with a large specific surface area (m2/kg), where van deer Waals bonds are bonding hydrogen to the material. The most successful types of adsorbents have been identified as activated carbons and certain metal-organic frameworks (MOF:s) which are very porous materials. Similar to liquefaction, adsorption require low temperatures due to the weakness of the van der Waals bonds. This method is however still considered on laboratory scale and have few commercial applications available. (Andersson and Grönkvist, 2019)

Chemical storage

Chemical storage of hydrogen implies that hydrogen is chemically bonded to other elements or molecules to form a stable molecule with advantageous qualities for different applications such as energy storage, transportation and distribution. (Andersson and Grönkvist, 2019)

The most common chemical compounds used as carriers of hydrogen are methanol and ammonia (Jackson *et al.*, 2020). Both of these hydrides are today widely used as bulk chemicals in the chemical industry and have thus a much larger application areas than simply hydrogen storage. For the most part, they are synthesized from natural gas but the technology of producing them from electro-synthesized hydrogen is already at a commercial state. One significant benefit of these chemicals is that they have an extensive infrastructure for transporting, storing and utilisation. Hence, chemical hydrides are not only a promising type of hydrogen storage but also represent an opportunity to substitute fossil fuel-derived bulk chemicals. (Andersson and Grönkvist, 2019)

Methanol

Production of methanol has been identified as a promising use of green hydrogen as it already has well-established areas of large-scale applications as feedstock in the chemical industry and fuel in the transportation sector (Galindo Cifre and Badr, 2007). The most common way of producing methanol on industrial scale today is by synthesizing syngas, which in turn is derived from natural gas by steam-reforming (Gumber and Gurumoorthy, 2018). However, it could also be produced by a catalytic reaction between hydrogen and carbon dioxide according to equation 8:

$$3H_2 + CO_2 \rightarrow CH_3OH + H_2O \tag{8}$$

The carbon dioxide used as feedstock in the production could come from various sources but is most commonly sourced from carbon capture and storage (CCS) technology. In this way, the carbon dioxide that would otherwise be emitted into the atmosphere can be recycled. To be fully renewable however, the CO_2 would have to come from bio-based energy with CCS (IRENA, 2021).

Methanol as fuel has been increasingly common since mid-2000's and is generally used in a blend with gasoline or diesel, on its own or for the production of biodiesel in the form of dimethyl ether (DME). With its high energy density, liquid state at room temperature and ability to be used in conventional internal combustion engines, it has been identified as a suitable replacement of the fossil fuels used in heavy transport and machinery today (IRENA, 2021). Another sector where methanol is attracting attention is the maritime sector (ibid). Since maritime shipping represents over 9% of all greenhouse gas emissions from the transport sector and cause high emissions of sulphur due to the diesel bunker fuel that is commonly used, the substitution to renewable methanol could have a significant climate impact.

Ammonia

Ammonia (NH_3) is along with methanol widely used chemical with many different applications. It has a long history of industrial-scale production and used globally as fertilizer, chemical feedstock as well as refrigerant (Jackson *et al.*, 2020). Today, most of all ammonia is derived from natural gas using the Haber-Bosch method, where hydrogen is produced from SMR and mixed with nitrogen. However, there are promising opportunities to produce carbon-neutral ammonia using green hydrogen, which could bring various benefits. Ammonia has a high hydrogen content (18 weight-%) and is simple to liquify. This makes it an effective medium for both storage and transportation. Since it does not include any carbon atoms, ammonia derived from green hydrogen has compared to methanol the potential to be a fully carbon-neutral hydrogen carrier. Ammonia has along with methanol been shown to have a large potential as fuel for long-range marine shipping as it can be used in existing combustion engines of today, thus reducing the need of costly investments in new technologies (Hansson *et al.*, 2020).

3.8 Cost of hydrogen systems

The cost of a complete power-to-gas system can be divided into two main parts. The first one being the components of the stack and the second relates to the balance of the plant, which includes water circulation, power supply and hydrogen processing (IRENA, 2020). The cost structure for PEM and AEL systems are similar on these two levels, with approximately 45% stack-related cost and 55% for balance of plant. The main difference between the technologies in this regard is that PEM electrolysers have a significantly higher costs of for stack manufacturing as they require expensive materials as platinum, gold or titanium which can make PEM electrolyser about 50% more expensive than AEL (ibid).

3.8.1 Current status of costs

Cost of Power-to-gas

The economic competitiveness of producing hydrogen through power-to-gas is today very location dependent as a large share of the total cost is power supply. In places where the power-to-gas plant have access to a steady supply of cheap renewable electricity, green hydrogen has already been shown to be cost-competitive with hydrogen sources from fossil sources (Glenk and Reichelstein, 2019). However, in most locations in the world, the levelized cost of green hydrogen ranges from 31 - 80 SEK/kg. This is to be compared with blue hydrogen at 12 - 21 SEK/kg and grey hydrogen at 7-16 SEK/kg. (IEA, 2020)

Another important parameter that influences the LCOH is the cumulative capacity factor of the power-to-gas plant. This means that when the operating hours of the plant decrease, the capital cost of the electrolyser become more dominant in the life cycle cost (IEA,2020). In applications where power-to-gas mainly is used to utilize curtailed power from overproducing power generation, the capacity factor tends to be low (1000 – 3000 hours per year). In these applications however, the power supply only marginally contributes to the production cost which decreases the operation cost of the power-to-gas plant significantly (ibid).

Cost of storage

The choice of storage has a significant impact on the total cost of hydrogen production. This varies greatly depending on which type of storage being considered. As mentioned, the most common way of storing hydrogen today is by using pressurized tanks. These vary in size, pressure and material depending on the application but are generally considered a relatively low-cost technology, with LCOS at around 2 SEK/kg H_2 (Bloomberg New Energy Finance, 2020). When considering pressurized storage, one must take into consideration the compression required. The cost of the compressor and its energy requirement depends on the desired pressure level of the gas. Table 2 shows a comparison of different hydrogen storage technologies.

Table 2 - Comparison of hydrogen storage options. (Bloomberg New Energy Finance, 2020)

	Pressurized gas	**Liquid hydrogen**	**Ammonia**	**Methanol**	**Underground caverns**
LCOS (SEK/kg H2)	1.9	46	28	45	2.3
Typical volume	Medium	Small – medium	Large	Large	Large
Time horizon	Weeks - Months	Days-weeks	Weeks-months	Weeks-months	Weeks-months

Cost of Gas-to-power

The conversion cost of hydrogen to power by fuel cells is mainly influenced by two factors – High investment costs and low overall efficiency. Due to the relative immaturity of fuel cells as a technology and the expensive materials used in the catalysts, they require a high capital costs of between 15 to 40 MSEK/MW depending on the specific type of fuel cell and its characteristics (Alshehri *et al.*, 2019). Also, when converting hydrogen to power, about 40% of the energy turns into low-grade heat at about 65 °C. It is therefore often difficult for power-to-power systems to become economically profitable. This is enhanced by the generally low operational hours of such systems which results in high LCOE. In the literature, LCOE of 4 000 – 6 000 SEK/MWh are reported (Weidner *et al.*, 2018).

3.8.2 Cost projections

Electrolysers

There is a strong consensus that both AEL and PEM systems are facing a continued rapid decline in costs, as displayed in table 3. IRENA (2020) points out that investment costs for both types of electrolyser systems could decrease by over 40% in until 2030 and over 80% in 2050, given the current development. This claim is supported by Peter Rudebrink (2021), who states that investment costs for PEM electrolysers could fall by 50% in the coming 5 to 10 years. The cost decline is mainly a result of electrolyser manufacturing costs being heavily dependent on automation, economies of scale and technology improvement. These have all been ramped up significantly the last years and are expected to accelerate (IRENA, 2020).

The largest potential of cost reduction is identified for PEM electrolysers, which is a less mature technology compared to AEL. There are currently many ongoing research projects with the aim of replacing some of the rare and expensive materials used in the PEM stacks, such as platinum and gold with cheaper and more available materials. If these attempts prove to be successful, the investment cost of the stack could significantly reduce costs. For both PEM and AEL systems, manufacturing of the stacks represents a promising area of cost reduction as component standardisation and process automation are achieved to a greater extent. Also, the upscaling of production is projected to reduce costs for the auxiliary components. (IRENA, 2020)

Table 3: CAPEX projections of electrolysis (Thomassen, 2019).

Technology	CAPEX 2020 (SEK/kW)	CAPEX 2025 (SEK/kW)	CAPEX 2030 (SEK/kW)
AEL	500 - 700	470 - 670	< 450
PEM	800- 1 100	500 - 590	< 500

Fuel cells

Similar to electrolysers, the capital costs of fuel cells are expected to rapidly decrease in the coming years. This is also due to increased manufacturing rates which allow for economics of scale and standardized solutions. Reports like *Path to Hydrogen competitiveness* by Hydrogen Council (2020), claims a cost reduction of 65% by 2030.

3.9 Hydrogen market

As mentioned in chapter 3, the demand for green hydrogen is projected to grow fast in the coming years due to the combination of cost decline, increasing areas of application and strong international as well as national policies that supports the expansion of the hydrogen economy (IRENA, 2020). Today, there are a number of sectors that already invest heavily in substituting fossil-based fuels and materials with green hydrogen in order to reduce their environmental footprint while continuing their operation. In Sweden, the major sectors of increasing demand are identified in the chemical and process industry, metal industry and the transport sector (Fossilfritt Sverige, 2021).

In a recent report from FCH (2020), the Swedish energy system is modelled to project the hydrogen demand in 2030. Using a low and a high scenario, the report concludes that the yearly hydrogen demand will range from 1 660 GWh to 4890 GWh, with industry and transport sectors making up the majority. To supply this demand, a total 400 – 1 170 MW power-to-gas capacity will be required (FCH, 2020). In figure 6, the projected demand of each sector can be seen.

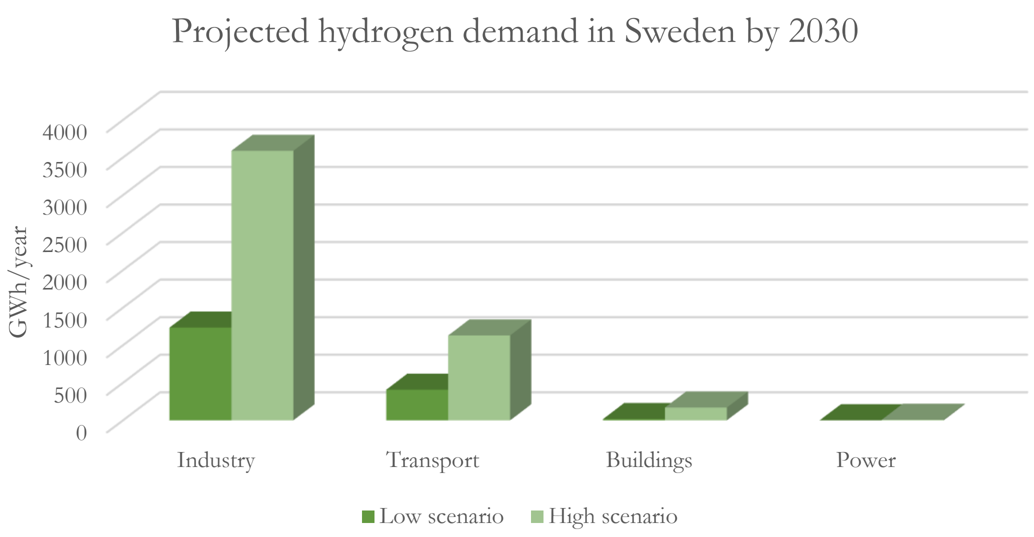

Figure 6 - Projected hydrogen demand for 2030 (FCH, 2020)

An important question that has been addressed by Fossilfritt Sverige (2021) is how the production, distribution and consumption will be integrated efficiently. One key parameter is transportation, which today represents a large share of the total cost in the hydrogen chain. To minimize the need of long transportation or the expansion of expensive infrastructure such as pipelines or large-scale storage, they predict that the future hydrogen economy in Sweden will be centred around industry dense clusters. These will also most likely be logistical hubs with access to maritime and road transport which are already adapted for hydrogen transport. (Fossilfritt Sverige, 2021)

3.9.1 Chemical industry

The chemical industry is already a large consumer of hydrogen, as it is commonly used as feedstock in the production of bulk chemicals such as ammonia and methanol. Typically, hydrogen is supplied to these processes by SMR of fossil fuels such as natural gas and coal (Gumber and Gurumoorthy, 2018). By substituting it with green hydrogen, large amounts of emissions of greenhouse gases could be reduced. An example of this is Liquid Wind, who aims at establishing over 10 production sites of renewable methanol by 2030. Their first project is planned to be commission in 2024, with a yearly production of 50 000 tonnes methanol from green hydrogen combined with biogenic CO_2 from Övik Energi's Hörnebergsverket (Övik Energi, 2021).

3.9.2 Steel industry

One of the largest future markets for green hydrogen is projected to be the steel industry, which in Sweden has proclaimed to be carbon neutral by 2045 (Regeringskansliet, 2018). Due to the very energy and emission intense process of conventional steel producing, this would have a significant effect on Sweden's total CO_2 emissions. HYBRIT, a joint venture of SSAB, LKAB and Vattenfall has the aim of developing a fully fossil free value chain of Swedish steel. By replacing the process of blast furnace where coke is currently used to reduce the iron ore with a method based on direct reduction using green hydrogen to create a raw material adapted for manufacturing of steel in an electrical arc furnace (Jernkontoret, 2020). A pilot project is already in operation, which will be followed by a 400 MW facility by 2025. Full-scale operation is planned to be in place by 2045 with over 1.3 GW electrolysing capacity, consuming over 7 TWh of green hydrogen per year (ibid).

Along with HYBRIT, a new Swedish project has been launched called H2 Green Steel. It will be located in Boden and start producing steel using green hydrogen as early as 2024. The company aims at achieving a yearly production of 5 million tonnes of steel which will be distributed to the primary industry around Europe (H2 Green Steel, 2021). The production will require a 800 MW electrolyser plant which will be built on site (Montel, 2021) .

3.9.3 Transportation sector

A sector that has been recognized as one of the most promising markets for green hydrogen is the transportation sector. Hydrogen can be used as fuel in its pure state or in the form of methanol derived from green hydrogen as explained in chapter 3.7. Green methanol is as mentioned a promising fuel for the ships as well as heavy duty vehicles (IRENA, 2021). Hydrogen gas on the other hand is already used in fuel cell electrical vehicles (FCEV:s) which include cars, buses and trucks. A benefit of FCEV compared to battery electrical vehicles (BEV:s) is the significantly longer driving range and a shorter refuelling time (Matute, Yusta and Correas, 2019).

One challenge of FCEV:s is that they are currently considerably more expensive than BEV:s and the fact that electricity is cheaper than hydrogen gas (Cox *et al.*, 2020). However, FCEV:s can be a good complementary technology for applications which BEV:s are unfit for. Wallmark and Mohseni (2014) points out that hydrogen-fuelled buses and trucks are such applications. One major reason is that heavy vehicles need large amounts of energy storage to drive long ranges. FCEV have the advantage of storing energy in the form of hydrogen at low weight compared to batteries and having a significantly shorter refuelling time (Rose, 2020). This claim is supported by the investments of large truck manufacturers like Volvo, Toyota and Daimler, who already have launched trucks powered by fuel cells. Volvo has among others proclaimed that for long-haul transport, hydrogen will likely be the most feasible diesel substitute. (Vätgas Sverige, 2020).

Another long-haul transport that is likely to become a large market for fuel cell technology is the maritime sector. Andreas Bodén (2021) at Powercell points out coastal shipping as especially promising due to the opportunities of refuelling and the large storage capacity available on ships. The maritime sector represents a substantial part of the Swedish transport energy use, with 28.5 % of the total final energy consumption by transport in 2017 (FHC, 2020). Ships are today almost exclusively power by fossil fuels which means that green hydrogen could have a large environmental impact in substituting conventional fuels (ibid).

One reason that the transportation sector is an especially promising market for hydrogen producers is that the main competing alternatives are diesel and petrol, which today are relatively expensive fuels. This makes it possible to sell hydrogen to the end-costumer as fuel to a price of 80–100 SEK/kg which is per kilometre of driving range cheaper than both petrol and diesel (Matute, Yusta and Correas, 2019; Johansson and Gustavsson, 2020). The high market price of hydrogen as fuel makes it an attractive market for small-and large-scale hydrogen producers.

In FCH (2020), the Swedish energy sector is modelled in order to project the yearly hydrogen demand in 2030 for a high and a low scenario. The report concludes that the transport sector will increase its hydrogen demand to 408 – 1 130 GWh per year, equivalent to 10 400 – 29 000 tonne hydrogen.

3.10 Opportunities of financing

As mentioned in section 3.1, EU has announced large investments in the European hydrogen economy. Of the 430 billion Euro that has been assured for the hydrogen sector until 2030, 180 billion Euro will be provided as financial support for innovative and sustainable hydrogen-based projects. The first application round is already finished but there will be many more to come until 2030, which will allow European actors to obtain financial support. For Swedish actors, there are also opportunities for financial support through the Swedish energy agency *Energimyndigheten*'s project *Industriklivet.* (Fossilfritt Sverige, 2021)

3.11 Safety aspects

Hydrogen in gaseous form is highly explosive and flammable if mixed with oxidizing agents like oxygen, chlorine or nitrous oxide. The low required ignition energy makes safe handling a critical issue. The hydrogen molecules are very small which could cause leakage of the gas though porous materials or tight fissures. Also, the low density of the gas will always find its way upwards and could therefore accumulate if not ventilated out (Linde, no date). Although the risks of handling hydrogen are real and must be treated accordingly, the industry has been using hydrogen in large scale for over 100 years which have resulted in clear routines, standards and working practices (Fossilfritt Sverige, 2021). Considering this, safe use of hydrogen is not different from the use and handling of other fossil fuels like natural gas or gasoline which have similar hazardous effects if not treated properly. In Sweden, the handling of hydrogen is covered in the *Law of flammable and explosive elements* (*Lagen om brandfarliga och explosiva varor* (SFS 2010:1011))along with other legislations that are mainly intended for energy gases like propane, natural gas and biogas (ibid).

3.12 CertifHY

In order to establish a common framework for the guarantees of origin of green hydrogen, the certification system CertifHy has been developed by a consortium of stakeholders active in the hydrogen sector in Europe. The project has been founded by the EU with the objective of defining a broadly acceptable definition of green and low-carbon hydrogen as well as designing and implementing a scheme to determine the guarantees of origin. The certificate will be a decisive factor when EU funds are distributed to projects in the scope of EU's hydrogen strategy (CertifHy, 2019) .

The CertifHY framework is based on benchmarks of the carbon footprint of hydrogen produced at a plant. This classification system allows a producer that uses a mix of energy sources, of which not all are categorized as renewable, to get permission to label a proportional amount of the hydrogen as green or low-carbon. By following the classification scheme presented in figure 7, the amount of green and/or low-carbon hydrogen from a producer can be determined. Only these volumes will be granted the certificate (ibid).

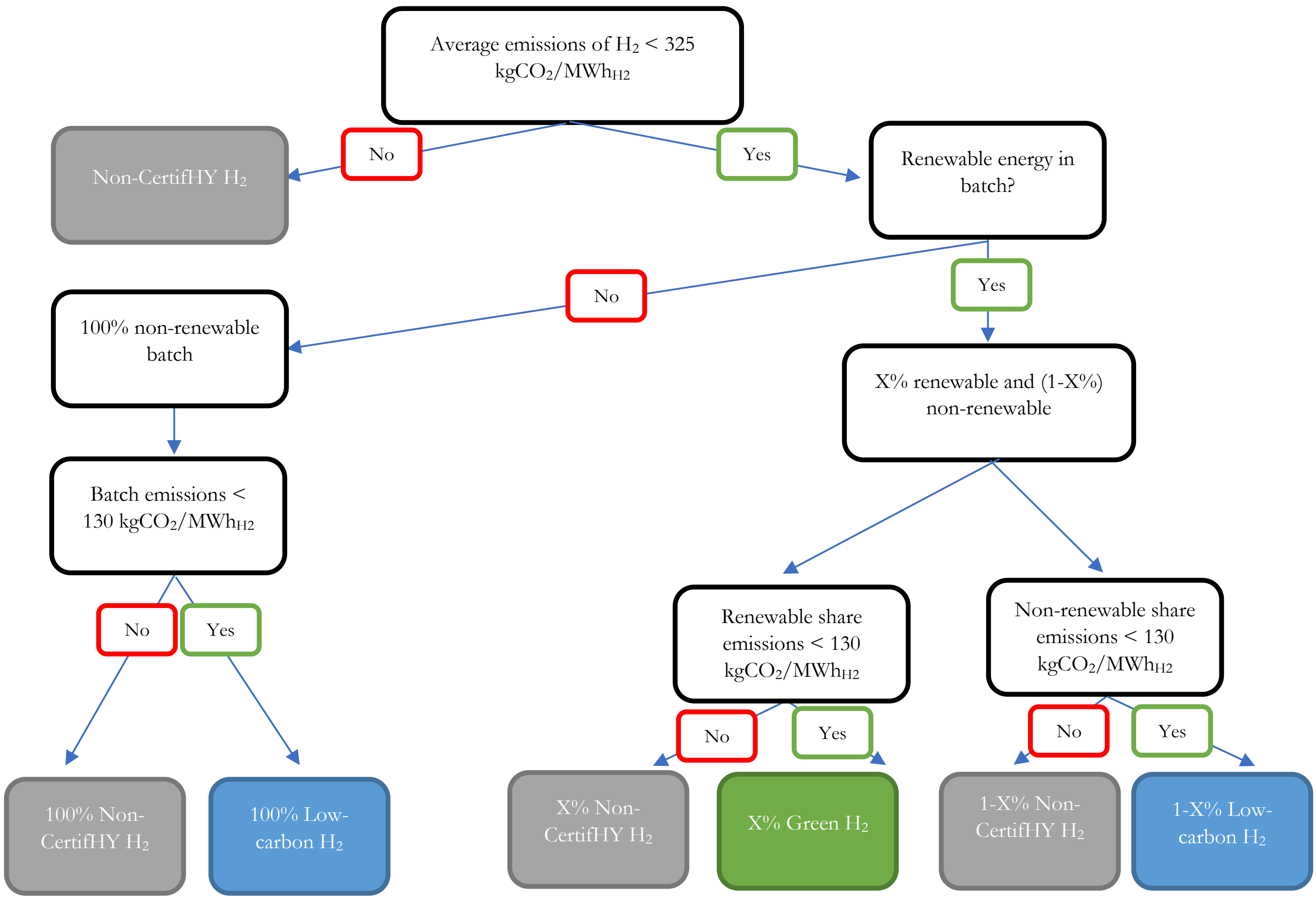

Figure 7 - CertifHY classification scheme (CertifHY, 2019)

4 Case-study – Hydrogen production at IKV

In the following section, the specific circumstances of the case study are presented and evaluated to identify opportunities, limitations, technical requirements. This section also presents a possible method of dimensioning the technical components required for hydrogen production.

4.1 Market analysis for IKV

Hydrogen market prospects

As mentioned in section 3.9, hydrogen production and consumption benefit largely of being in geographical proximity in order to avoid costly transports and long-term storage. This is why the hydrogen economy is projected to be centred around clusters where production and consumption are local. The case of Söderenergi and IKV has the advantage of being located in Södertälje harbour, which today is an industry dense area as well as a logistical hub for shipping, road transport and railway. Therefore, the logistical potential of distributing hydrogen from Söderenergi's facility is favourable, with access to its own docks as well as roads for truck delivery.

Based on the literature study and interviews with experts within the field, the most feasible hydrogen markets for Söderenergi are the transportation sector and locally based industries that today use hydrogen in their operation (FHC, 2017); (Larscheid *et al.*, 2018). The price at which hydrogen can be sold differs depending on the application and specific circumstances such as local competition and contractual arrangements. In the literature it is estimated that a producer can sell hydrogen to mobility market retailers at a price of 40-70 SEK per kg (FHC, 2017). The industry sector has generally lower hydrogen prices as they often compete with SMR-produced hydrogen from fossil sources, ranging from 20 SEK per kg to 40 SEK per kg (IRENA, 2020).

For the case of Söderenergi, the price at which hydrogen could be sold at was estimated at 40 SEK per kg. This was chosen as a conservative value as it is in the lower range of the expected retail price for the mobility sector. Due to the uncertainties of this parameter, the price of hydrogen was further investigated in a sensitivity analysis.

The estimated market size for hydrogen was estimated using FCH's (2020) low-demand scenario for 2030, where the transportation sector alone represents 10 400 tonnes of hydrogen annually. In this project, Söderenergi would only be able to supply a fraction of this due to limited production capacity. But this value is used as an upper limit, so that the demand is not overestimated.

Opportunities of Power-to-gas-to-power at IKV

A business model that also could be applied by Söderenergi is to make use of the hydrogen for grid services by installing a fuel cell as an addition to the power-to-gas system. In this way, the hydrogen could be produced and stored during down-regulating hours, when the electricity is cheap. During up-regulating hours, when a producer gets additional revenue for providing reserve power, the fuel cell can use the hydrogen to produce electricity. In order to participate in the regulating power market (RPM), a requirement is to be able to activate the reserve power within 15 minutes. As mentioned in section 3.6, this can be met by PEM fuel cell. This is a concept that has been studied by for example Weidner *et al.* (2018). The literature does however lack such studies in a Swedish context.

4.2 Technical requirements

Electrolyser unit

For the case study of IKV, the PEM electrolyser was chosen as the most suitable technology according to table 4. The choice was mainly influenced by its fast response time to fluctuations in the power input compared to the alkaline electrolyser and SOEL. It also has the advantage of operating over the entire load range, which gives it a larger operational flexibility. Even though it is currently the more expensive option, the cost reduction curve is the steepest for PEM technology and the literature as well as experts' opinions from the interview study confirm that PEM electrolysers will most likely be cost-competitive with AEL's in a few years. SOEL was considered unfit for this case since it is not available on commercial scale and not suited for flexible operation.

Table 4 - Criteria comparison of different types of electrolysers.

Criteria	AEL @ 2025	PEM @ 2025	SOEL @ 2025
Technology maturity	+	+	-
Investment cost	+	+	unknown
Flexibility	-	+	-
Area requirement	-	+	-

There is a wide range of commercially available PEM electrolyser sizes, ranging from a few kW to several MW capacity. For sizes up to approximately 2.5 MW, the electrolyser along with the necessary auxiliary components are usually fitted into a container, which makes the system compact and is a practical feature for outdoors applications where surface area is limited (NEL, 2020).

Storage and distribution

The most feasible option for storage and distribution of hydrogen was chosen to be so called tube-trailers, which are cylindrical vessels containing pressurized hydrogen gas. This is the most commonly used method in the light industry and transportation market (FHC, 2017) and is a more mature technology compared with other storage options. It also has the advantage in that it is a flexible solution, simple to scale up or down depending on the need as well as relatively low investment costs compared to alternative hydrogen storage technologies (Bloomberg New Energy Finance, 2020).

The storage system consists of cylindrical tubes made of steel, which are bundled together and placed in a container. This makes it practical for further distribution as it can easily be loaded on to a trailer or a ship (Rödl, Wulf and Kaltschmitt, 2018). Standard configurations of this kind consist of steel cylinders which have a total effective hydrogen storage volume of up to 30 m^3 and have an operating pressure at 200, equivalent to 450 kilograms of hydrogen in one container. These systems have an investment cost of 500 euro per kg of hydrogen and is due to is maturity not expected to fall in costs in the future (FHC, 2017).

Other forms of hydrogen storage mentioned in section 4.5 where not considered feasible for this case due to the extra process requirements of transforming hydrogen into hydrides such as methanol and ammonia. Also, liquefaction of hydrogen was considered too energy consuming as it need to be cooled to -253°C, which typically require 10 kWh per kg of hydrogen (Rödl, Wulf and Kaltschmitt, 2018). This is to be compared to compression from 20 to 200 bar which consumes around 3 kWh per kg. Underground storage for this case was not considered due to the geographical limitations of such system.

Compressor

The energy required to compress hydrogen gas can be determined by equation 9 and values from table 5, which give the compressor work for reversible adiabatic compression. For adiabatic conditions, the process is assumed to have no heat transfer between the hydrogen and the ambient environment . (Godula-Jopek, 2015)

$$W_{adiabatic\ compressor}\ (kWh) = m_{H2} * \frac{1}{3600} \frac{\gamma}{\gamma-1} * R * T * \left(\left(\frac{p2}{p1}\right)^{\frac{\gamma}{\gamma-1}} - 1 \right) \tag{9}$$

By applying the isentropic efficiency of the compressor, η_{is}, the actual work can be determined by equation 10.

$$W_{compressor} = \frac{W_{adiabatic\ compressor}}{\eta_{is}} \tag{10}$$

*Table 5 - Compressor parameters (Godula-Jopek, 2015). *Assumed value.*

Parameter	Value	Unit
m_{H2}	Variable	Mass flow of hydrogen (kg/h)
γ	1.4	specific heat ratio of hydrogen
R	8.314	ideal gas constant $\frac{kJ}{mol*K}$
T	289.15	Temperature of hydrogen
η_{is}	70% *	Isentropic efficiency of compressor

Fuel cell

The most suitable fuel cell for this application was selected to be a PEM fuel cell due to its fast response time, compact design, and commercial availability. As with electrolysers, stationary PEM fuel cells can be fitted in containers which makes them suitable for outdoor applications. Today, such systems are available in sizes up to 2 MW of output power per container (Alshehri *et al.*, 2019).

4.2.1 Sizing of components

When dimensioning the components, the first step was to estimate the maximum available area at Söderenergi's facility. Hydrogen gas has due to its low-density large volume requirements. Therefore, the system needed to be designed so that it does not produce more gas than could be stored on the property. This was done by studying the overview map and identifying possible installation zones. The specific spatial requirement of each component was found it the literature and was then used to find the maximum allowable size that could physically fit in the identified zones.

From the overview map of Söderenergi's facility at IKV along with deliberations with Söderenergi, the available area for installation of power-to-gas components was found to be around 130 m^2 spread over two main zones. Since the identified zones were located outside, containerized components were the most suitable options. A summary of the system features is shown in table 6.

Hydrogen storage

Given the available area, it was estimated that the maximum storage size would be two containers with the capacity of 450 kg H_2 each. The hydrogen was assumed to be sold in batches of the whole storage capacity once every day, meaning that it would need to be filled every 24 hours.

Electrolyser

The most suitable electrolyser commercially available was selected to be a 2.5 MW PEM electrolyser with a production capacity of 47.5 kg H_2/h. From the simulation, using a hydrogen price of 40 SEK/kg, it was shown to supply enough hydrogen to fill up the 900 kg storage at the end of each 24-hour period.

Compressor

By using the maximum mass flow of the selected electrolyser, it was found by applying equation 10, that required rated power of the compressor was 120 kW.

Fuel cell

For this study, a 2 MW PEM fuel cell was selected to be the most suitable option as it was the largest available size on the market.. By maximizing the output capacity, more balancing power can be provided. Also, since the minimum bid for the frequency control market is expected to change to 1 MW in the coming years, the fuel cell was dimensioned to cover at least this limit.

Table 6 – Hydrogen system parameters used in the model.

PEM Electrolyser (NEL, 2020)	
Electrical input capacity	2.5 MW
Hydrogen production rate at full load	45 kg H_2/hour
Average power consumption	50.4 kWh/kg H_2
Start-up time (cold)	< 5 min
Start-up time (warm)	< 15 sec
Ramp-rate (%-of nominal load)	>15 %/sec
Output pressure	30 bar
Water consumption	8 liter/kg H_2
Size	61 m^2 2x (12.2 x 2.5) containers)
PEM Fuel Cell (FHC, 2017)	
Electrical output capacity	2 MW
Efficiency (%LHV)	50 %
Ramp-rate (%-of nominal load)	5%/sec
Size	27 m^2 (12.2 x 2.5 m container)
Compressor 30 → 200 bar (FHC, 2017)	
Rated power	120 kW
Specific power consumption	2.4 kWh/kg H_2
Size	11 m^2
Storage (FHC, 2017)	
Pressure level	200 bar
Hydrogen storage capacity	450 kg H_2/container
Container size	27 m^2 (12.2 x 2.5 m container)
Nr of containers	2
Total amount of hydrogen storage	900 kg

4.3 Possibility of waste heat recovery

Electrolyser

In low-temperature electrolysis technologies like PEM systems, the LVH-based efficiency of transforming electrical energy into hydrogen is between 60-75%. The remaining part is turned into heat which needs to be led out in order not to decrease the operational performance of the process. Electrolysers are therefore equipped with a cooling system, where flowing water cools the electrodes. In PEM systems, the cooling water exits the electrolyser at a temperature of 65 degrees (Rudebrink, 2021).The heat is usually wasted by dispensing the cooling water due to relatively low-quality energy in the water which makes it non-usable as a direct source of heating for many purposes (Li *et al.*, 2019). Given that Söderenergi is a district heating producer, there could be potential to utilize this heat in the district network. It would however need upgrading in order to reach the desired temperature of 90 degrees or used in an alternative way, like injecting it to the return water.

Fuel cell

Similar to the PEM electrolyser, a PEM fuel cell generates heat when operating and is usually kept at 60-80 degrees Celsius. The heat is mostly due to ohmic resistance in the flow of electrons and protons, hydrogen mass transport at the anode and the electrochemical reactions (Nguyen and Shabani, 2020). To not risk losing performance due to overheating, the stacks need to be cooled. This is done by letting water circulate around the stacks and absorb the excess heat. Of the total energy entering the fuel cell, about 45-60% leaves in the form of heat which could be recovered in order to increase the system efficiency. As with electrolysers, the water temperature exiting the fuel cell is around 65 degrees which cannot be directly supplied to the district heating network.

4.4 Development of scenarios

The scenarios were developed to illustrate two separate business models in which hydrogen production serves two different purposes described in the following sections. Each scenario was then simulated for two years with distinctly different electricity market characteristics to evaluate economical potential and environmental impact of the business models in extreme cases. Based on an analysis of historical electricity prices, 2018 and 2020 was chosen as the most suitable for the scenario analysis. As shown in figure 8 and 9, 2018 was a year with generally high spot prices and relatively stable price curve over the year, while 2020 was a year with unusually low spot prices combined with high variation.

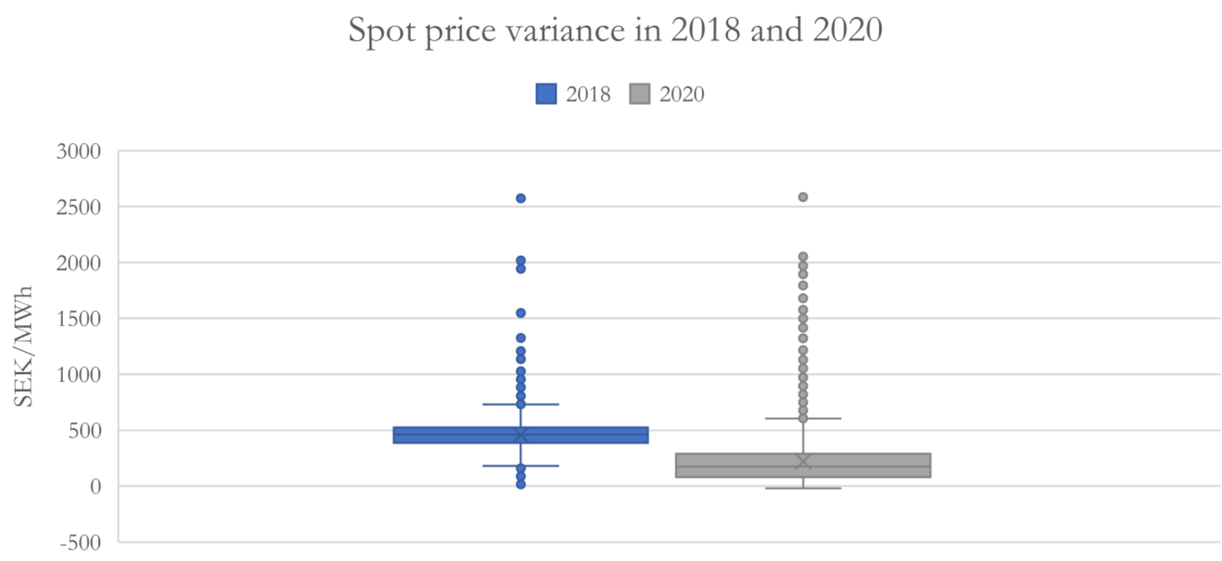

Figure 8 – Variance in spot prices for 2018 and 2020. 2018 was a year generally high prices, with a mean price of almost 500 SEK/MWh. 2020 however, was a year of generally low prices but with greater variance which is a sign of large price fluctuations. (Nordpool, 2021).

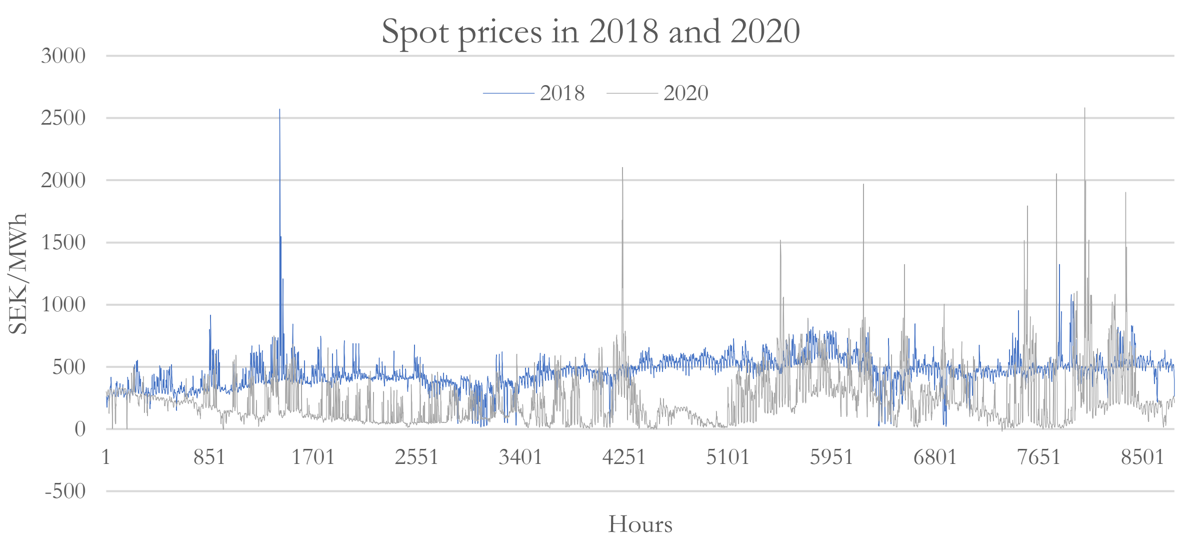

Figure 9 - Spot price variation for 2018 and 2020 (Nordpool, 2021).

4.4.1 Scenario 1: Power-to-gas

In the first scenario, the electrolyser has the objective to produce hydrogen gas to sell on the market. The market showed that the demand of green hydrogen will increase in the coming years, especially in the transportation sector and industry. The limiting factor for dimensioning showed however to be the available storage volume of hydrogen which set the limit of hydrogen storage to 900 kg. The storage was assumed to be emptied for delivery once a day. The retail price of hydrogen was set to 40 SEK/kg, which is a generally lower price than the average price for hydrogen retailers in the mobility market but higher than the industry market price. This parameter was investigated further in the sensitivity analysis. The power-to-gas system is depicted in figure 10. Since the system is connected to the grid, IKV can choose to down-regulate its production of electricity if the down-regulating price is low enough by redirecting the power flow to the electrolyser. In this way, the cheapest possible electricity can be utilized to produce hydrogen which can later be sold as a product and therefore minimize the total cost. For times when IKV is not producing any electricity due to maintenance or low heat demand, the electrolyser can be run on grid electricity at an additional grid expense.

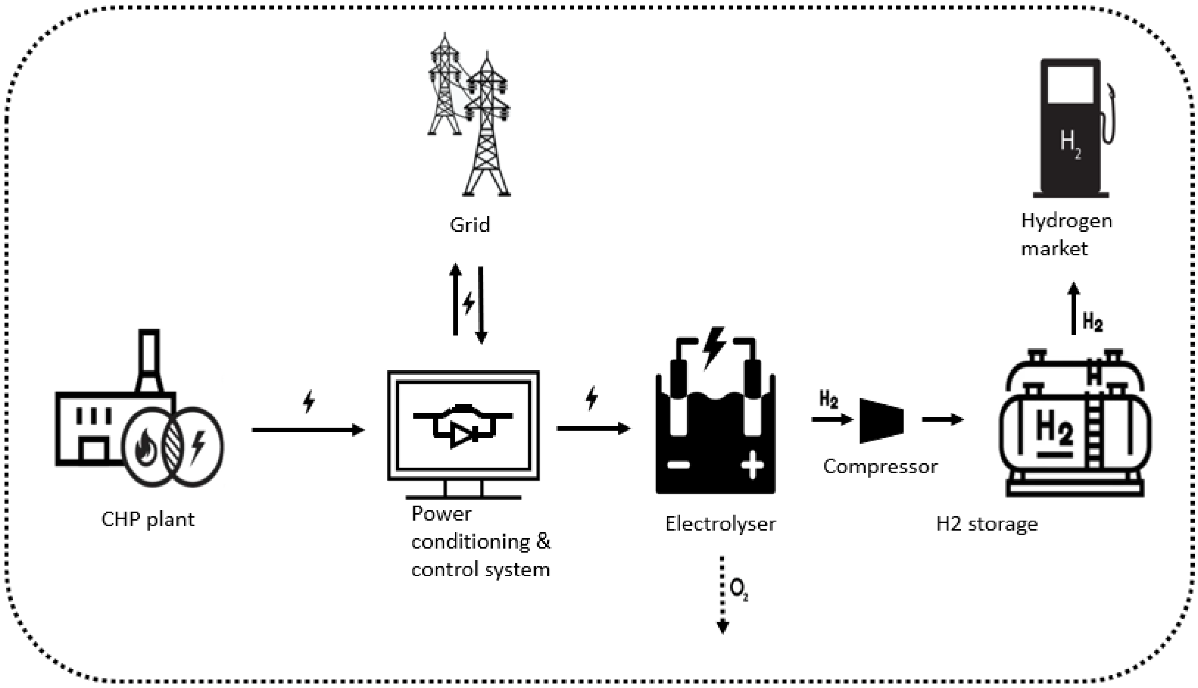

Figure 10 - Schematic of a Power-to-gas system

4.4.2 Scenario 2: Power-to-power

The second scenario was developed to analyse the performance of a power-to-power concept, where the produced hydrogen is used to generate electricity during peak hours. The objective of the proposed model is to provide grid services through frequency balance. This concept, showed in figure 11, is similar to scenario 1 in the sense that electricity generated in IKV can be sold to the grid or used for hydrogen production. The hydrogen is stored in tanks and consumed in the fuel cell to produce electricity which is sold at up-regulating prices.

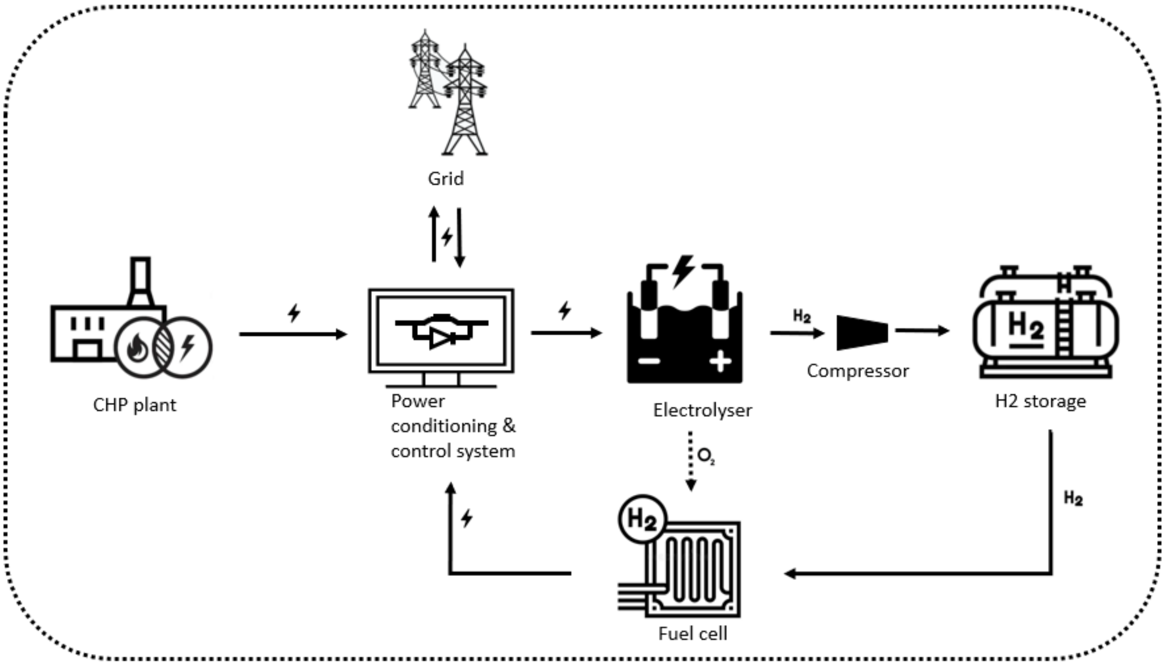

Figure 11 - Schematic of a Power-to-Power system

4.5 Environmental impact

The environmental impact of the scenarios is evaluated on the basis on fuel substitution. That is, the process at Söderenergi can be said to have an environmental impact if replacing other energy sources or products that have a different carbon footprint. In the power-to-gas scenario, the produced hydrogen is assumed to replace diesel used in transportation vehicles and ships. The specific emission factors can be seen in table 7.

For the power-to-power scenario, the produced electricity by the fuel cell is assumed to replace marginal power generation. This assumption is based on the fact that the objective of the fuel cell is to generate power during up-regulating hours, when power production is most profitable. That means that it will activate during hours of either power deficit or peak consumption in the system which is when the peak-power plants are also active. These power plants are the most CO_2 -emission intense in the Swedish power system, having an estimated emission factor of 400 kg CO_2/MWh (Elforsk, 2008).

The carbon footprint of the hydrogen produced at IKV was calculated based on the known fossil CO_2-intensity of the fuel. 90% of the fuel used in the boiler is biomass, which is only attributed biogenic emissions. The remaining 10% is classified as solid waste, which carbon emissions due to combustion was derived from Naturvårdsverket (2019). This resulted in a carbon footprint of 12.7 kg CO_2 per MWh of hydrogen, which is the value used in the environmental analysis.

Table 7 - Emission factors. Sources: [1] (Naturvårdsverket, 2020) [2](IRENA, 2019a), [3]10% of IKV input fuel is assumed to be of solid waste (Naturvårdsverket, 2019), [4] (Elforsk, 2008)

Energy source	Emission factor (kg CO2/MWh)
Diesel	260[1]
Gray H_2 (from SMR)	285[2]
H_2 from IKV	12.7[3]
Average grid electricity	24[1]
Marginal grid electricity	400[4]

4.6 Techno-economic modelling

In order to evaluate the performance of the scenarios, a mathematical model of the CHP plant was developed. The model was created with the aim representing the hourly operation of IKV during a given period of time. Given certain parameters like fuel cost, O&M costs related to heat and power production as well as electricity prices and hourly heat demand, the model optimizes the operation at lowest possible production cost of district heat. As complete modelling tools like BoFiT were not available in this project, the model was developed from scratch using Python as programming language. To solve the optimization problem, the Python function PuLP was used. PuLP is based on mixed integer linear programming (MILP) and is a common method to find optimal solutions to complex problems. A more comprehensive description can be found in Appendix A.

Verification of model

To verify the model, it was tested without any integration of hydrogen systems against real data obtained from Söderenergi. Table 8 shows a comparison between the real production of IKV in 2020 and the production that was simulated using the electricity prices and the heat demand of 2020. As can be seen in the table, the main errors occur in the distribution between back-pressure mode and by-pass mode, where the model more often prioritizes running IKV in back-pressure mode. The differences are however small enough to make clear that the model grasps the dynamics between heat production and electricity prices.

Table 8 - Real production data obtained from Söderenergi compared with calculated production data.

Source	Back-pressure mode (GWh)	By-pass mode (GWh)	Flue gas condenser (GWh)	Power generation (GWh)
Söderenergi production data	736	138	282	385
Model	743	121	285	388

When the verification had been accomplished, the scenario schemes from figure 10 and 11 where integrated into the model along with the technical data in table 6 and economic parameters from table 9.

4.7 Economic analysis

4.7.1 Net present value

To evaluate the economic aspect of the implementation of the power-to-gas systems used in the scenarios, the net present value (NPV) of the investment was calculated with equation 11 and the related costs presented in table 9. NPV represents the economic value of all cash flows during the expected life-span of a project and is a widely used method for evaluating investments (CFI, 2021).

$$NPV = \sum_{t=0}^{T} \frac{Revenue_t - Costs_t}{(1+r)^t} \tag{11}$$

Where r is the discount rate and t the time period at which the net cash flow is calculated and T economic lifetime of the investment. In order to find the economic impact of the scenarios, a baseline case with no new installations were used as a reference. Thereafter, the economic impact was evaluated as the total net difference between the reference case and the studied scenario.

4.7.2 Levelized cost of hydrogen

A method similar to NPV is levelized cost of energy (LCOE), shown in equitation 12. This is primarily used to compare the cost of energy from different producers. By including the return of investment, the method can be applied to calculate the minimum price of energy at which the investment can be considered profitable. The same methodology can be applied for estimating the minimum retail price of hydrogen a project needs to have in order not to make a net loss.

$$LCOH = \sum_{t=0}^{T} \frac{\frac{CAPEX_t + OPEX_t}{(1+r)^t}}{\frac{m_{H_2}}{(1+r)^t}} \tag{12}$$

Where m_{H2} is the total amount of hydrogen produced during the economic lifetime.

Table 9 – Economic parameters used in the model.

PEM Electrolyser (Böhm *et al.*, 2020)	
CAPEX electrolyser	10 000 SEK/kW
OPEX electrolyser	3 % of CAPEX/year
CAPEX stack	40% of CAPEX
Stack replacement hours	40 000 hours
OPEX water	9 SEK/1000 liter
Compressor (30 → 200 bar) (Weidner *et al.*, 2018)	
CAPEX compressor	980 000 SEK
OPEX compressor	3 % of CAPEX/year
Lifetime	20 years
Storage (FHC, 2017)	
CAPEX storage	4 500 SEK/kg H2
OPEX storage	3 % of CAPEX/year
Fuel cell (FHC, 2017)	
CAPEX fuel cell	15 000 SEK/kW
OPEX fuel cell	3 % of CAPEX/year
Other parameters	
Installation cost	1 000 000 SEK
Price H_2	40 SEK/kg H_2
Electricity prices for SE3	Spot price from Nordpool
	Up-regulating price from Nordpool
	Down-regulating price from Nordpool
Discount rate	5 %
System lifetime	20 years

5 Simulation results

In this section, the results the simulation of the model are presented for each scenario along with each respective sensitivity analysis.

5.1 Scenario 1: Power-to-gas

The results of the power-to-gas scenario show that for both examined years, hydrogen production is profitable during most hours at a retail price of 40 SEK/kg, with around 6 500 hours of operation in the 2018 case and 7 500 hours in the 2020 case . This is due to that the energy price of hydrogen is high relative to the revenue from selling electricity to the grid for hourly spot prices. Given the LHV of hydrogen at 33.4 MWh/kg, the price of energy corresponds to 1190 SEK/MWh$_{H2}$. With a total efficiency of the power-to-gas system at 62%, the breakpoint at which hydrogen production is more profitable than selling electricity to the grid is 720 SEK/MWh$_{el}$.

Hydrogen production & storage level as a function of electricity price

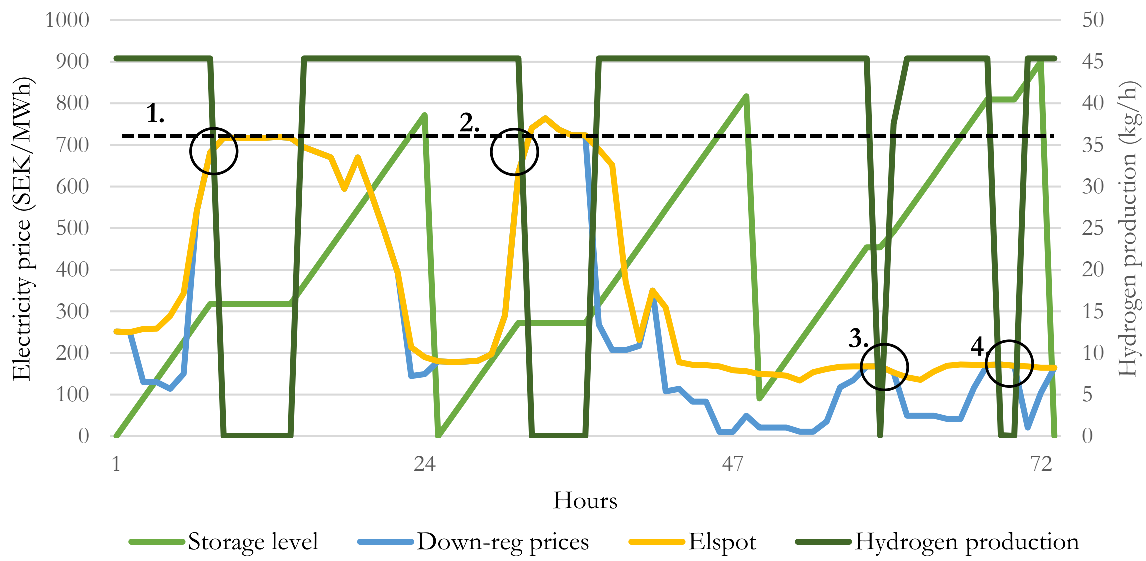

Figure 12 – Example of three days of power-to-gas operation as a function of electricity prices and storage capacity. At 1 and 2, the down-regulating price reaches the breakpoint of 720 SEK/MWh, and the electrolyser shuts down for the high-priced hours. At 3 and 4 the electrolyser pauses its production at the peak-priced hours to cost-optimally fill up the storage.

In figure 12, three days of operation are displayed and show how the production of hydrogen is driven by the price of electricity and the availability of storage. Since the storage is emptied every 24 hours, the optimization will favour hydrogen production as long as the down-regulating price is below 720 SEK/MWh or as long as there is enough capacity in the storage tanks. In point 1 and 2 on the graph, the electricity price is above the breakpoint of which hydrogen production is profitable and the electrolyser is therefore shut down even though the storage is not filled. In point 3 and 4 however, the electricity price is far below the breakpoint, but the electrolyser is still shut down due to lack of storage capacity that day. The optimization then choses to shut it down during the hours of peaking electricity prices and thus fill the storage tanks at the lowest possible cost.

The highest hydrogen yield was as mentioned found in the 2020 case, with an annual production of 340 tonnes. This would cover approximately 3% of the demand from the Swedish mobility sector in 2030, estimated by FHC (2020). From a market demand perspective, the yield can therefore be said to be realistic.

5.1.1 Economic impact

As mentioned, the main objective of IKV is to produce district heat at the lowest possible cost. To illustrate how the implementation of power-to-gas affects this objective, table 10 provides the average seasonal production costs of IKV for the two scenarios described above with the addition of a baseline scenario, where power-to-gas has not been applied. Table 10 also displays the annual production cost reduction which is the difference in the accumulated production cost of IKV between the baseline and the power-to-gas scenario. It can be seen that the annual cost reduction is significantly larger in the 2020 case. This is due to that the generally low spot prices of 2020 makes hydrogen production more profitable compared to the 2018 case and therefore generate larger savings in production costs.

Table 10 - Average production costs of IKV for three evaluated scenarios

Scenario	**Average production cost (SEK/MWh heat)**	**Accumulated net cost reduction compared to baseline (SEK)**
Baseline – 2020 (no PtG)	127 SEK/MWh heat	-
PtG – 2020	118 SEK/MWh heat	9 800 000 SEK
Baseline – 2018 (no PtG)	49 SEK/MWh heat	-
PtG (2018)	46 SEK/MWh heat	5 200 000 SEK

The payback period of the power-to-gas system for the two different cases is displayed in figure 13, where it can be seen that for the 2018 case, the break-even point of the investment is 10 years, including two electrolyser stack replacements which are made after 40 000 hours of operation. For the 2020 case the payback period is calculated to 4 years.

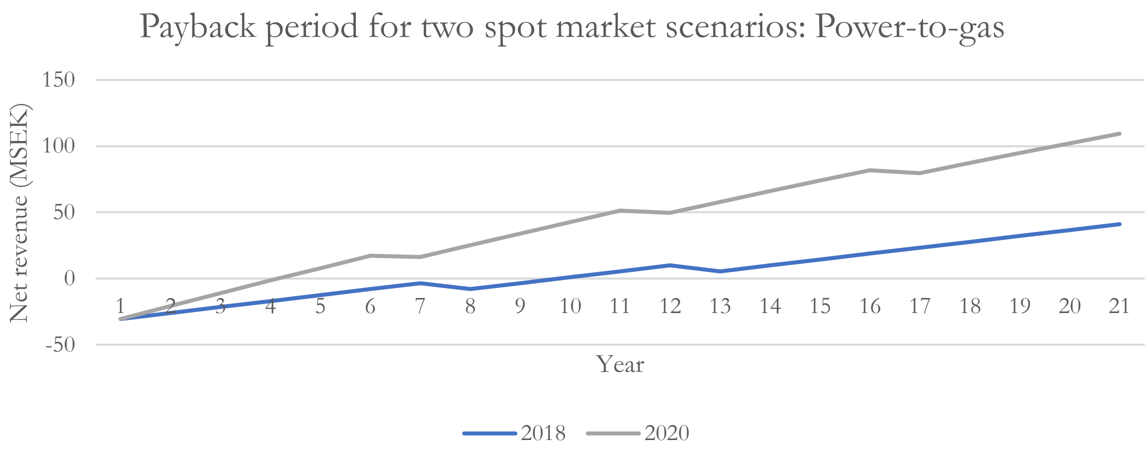

Figure 13 - Payback period of the power-to-gas system

5.1.2 Environmental impact

In the 2020 case, the produced hydrogen was calculated to reach 337 tonnes per year. If this replaces diesel, the total amount of avoided GHG-emissions is 2800 tonnes of CO_2-equivalents. If the electricity used in the power-to-gas process would instead be used to replace Swedish grid electricity as it is today, the reduction amounts to 300 tonnes of CO_2-equivalents. Therefore, the net emission impact of the implementation of power-to-gas is estimated at 2500 tonnes for the 2020 case. Similarly calculated, the net impact is 2100 tonnes in the 2018 case.

5.1.3 Cost of hydrogen production

The cost of producing hydrogen is in a lifetime perspective dominated by the cost of electricity and the investment costs for the components. Figure 14 displays the breakdown of the life cycle costs of the analysed power-to-gas system. It is clear that that the price of electricity is a major influence on the total life cycle cost in both examined years, but that it in the 2020 case is matched by the cost of equipment. The LCOH was calculated for a lifetime of 20 years, at a discount rate of 5%, and was found to be 38 SEK/kg H_2 and 24 SEK/kg H_2 for 2018 and 2020, respectively. The values are based on using the current CAPEX of electrolysers at 10 million SEK per MW in order to keep a conservative position. This parameter is examined further in the sensitivity analysis, as the CAPEX of electrolysers are forecasted to drop significantly in the coming years.

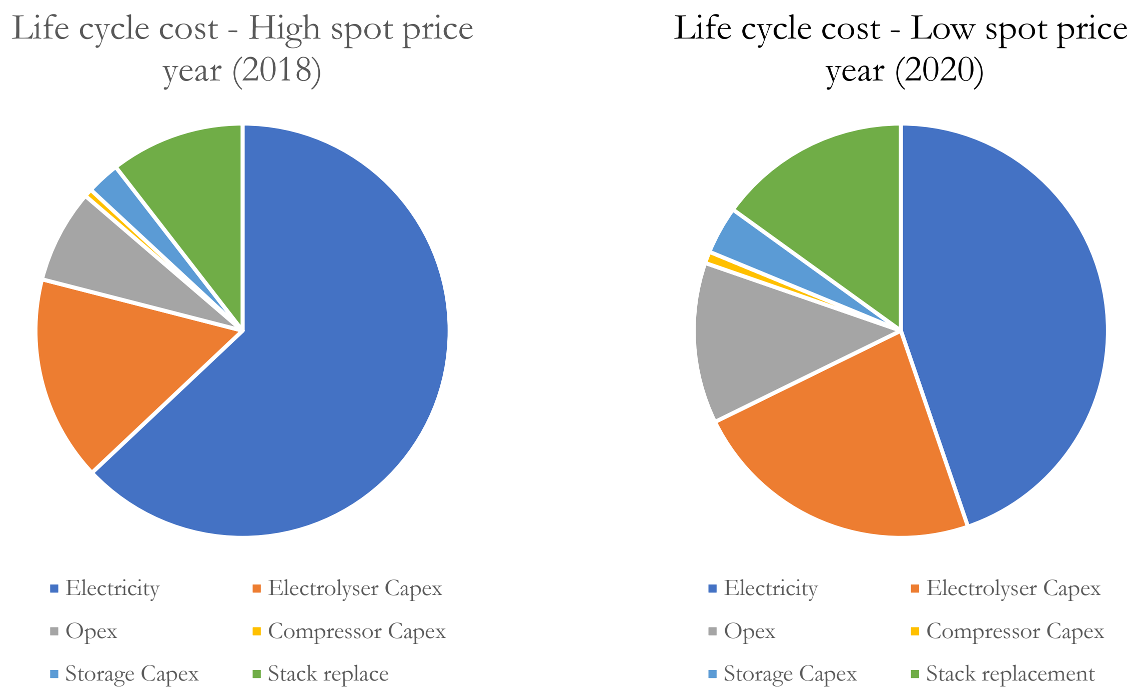

Figure 14 - Life cycle cost of the power-to-gas system for two different years at an electrolyser CAPEX of 10 MSEK/MW.

Another parameter that has a substantial impact on the LCOH is the capacity factor of the electrolyser, that is, how many hours of full load the electrolyser is operating. Figure 15 shows how the LCOH depends on the annual hours of operation of the power-to-gas system analysed in this case study. Using electricity prices of 2020 and 2018, one can see that the LCOH increases exponentially as the capacity factor decreases. This is due to that the high investment cost is distributed over less volumes of hydrogen, making each kilogram more expensive.

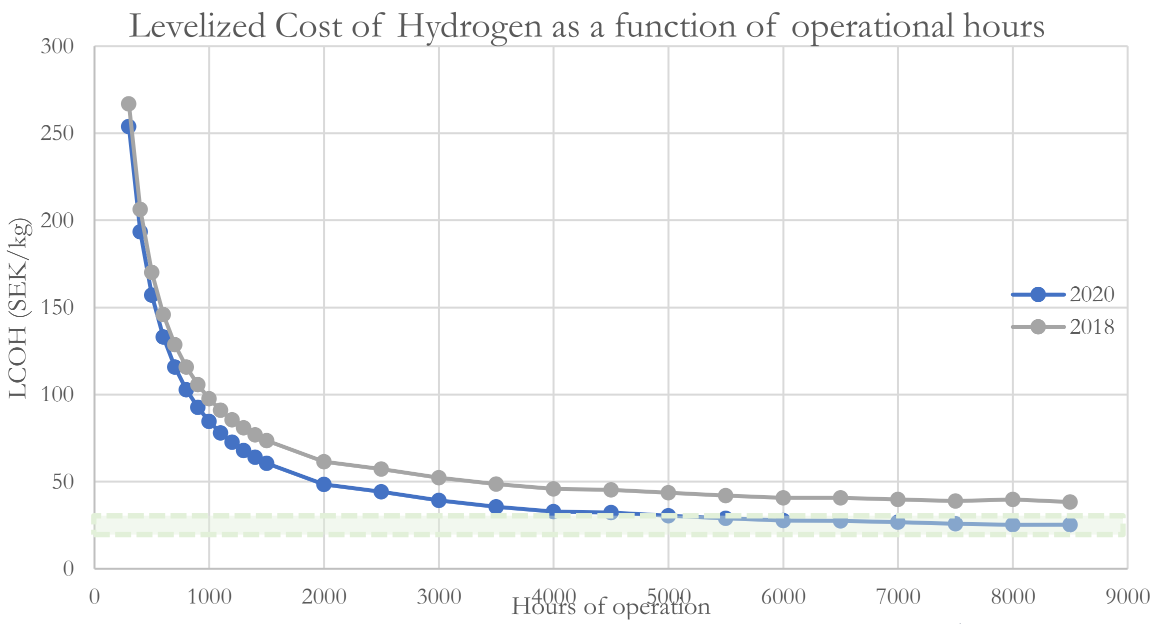

Figure 15 - LCOH as a function of operational hours. Values are based on a electrolyser CAPEX of 10 MSEK/MW. The green area represents the cost range of SMR-produced hydrogen, which is estimated at 15-30 SEK/kg.

5.1.4 Net present value

As presented in table 9, the annual economic benefit to Söderenergi in the power-to-gas scenario was calculated to be 4.5 MSEK in the 2018 case and 9.8 MSEK in the 2020 case. With an expected lifetime of the system of 20 years and a discount rate at 5%, the NPV of the investment was found at 14 MSEK and 60 MSEK for the 2018 and 2020 case, respectively.

5.1.5 Summarized results: Scenario 1: Power-to-gas

Table 11 - Results Power-to-gas scenario

Performance parameters	2018 – High spot price scenario @ 40 SEK/kg H_2	2020 – Low spot price scenario @ 40 SEK/kg H_2
Produced hydrogen	282 tonne H_2	337 tonne H_2
Electrolyser operational hours	6 490 hours	7 580 hours
Saved CO_2 emissions	2100 tonne CO_2	2 500 tonne CO_2
Economic benefit	4 MSEK/year	10 MSEK/year
NPV	14 MSEK	60 MSEK
LCOH (SEK/kg)	38 SEK/kg H_2	24 SEK/kg H_2

5.1.6 Sensitivity analysis – Power-to-gas

In the sensitivity analysis, the impact of hydrogen retail price and CAPEX of the electrolyser were investigated further. These were considered to be of significant economic importance but also of much uncertainty and were thus investigated further. Table 12 and 13 show how the NPV of an investment in a power-to-gas system in the two examined years differs when the retail price of hydrogen and CAPEX change.

In the 2018 case, hydrogen production will not be profitable at a retail price of 20 SEK/kg, which is what was assumed to be a competitive price for replacing SMR-hydrogen. The high price of electricity makes the revenue higher from selling the generated power on the spot market instead, even if the CAPEX of the electrolyser drops to 50% of today.

However, at hydrogen retail prices at 40 SEK/kg and higher, the analysis shows that power-to-gas is a viable investment. At such prices, hydrogen is competitive with other sorts of transportation fuels, like diesel and gasoline and could therefore be marketed to the mobility sector.

Table 12 - Sensitivity analysis of Power-to-gas scenario - High spot price year

2018 – High spot price year			
Hydrogen retail price / CAPEX	**20 SEK/kg (-50%)**	**40 SEK/kg (0%)**	**60 SEK/kg (+50%)**
10 MSEK/MW (0%)	LCOH: 60 SEK/kg NPV: -39 200 000 SEK	LCOH: 37 SEK/kg NPV: 11 700 000 SEK	LCOH: 35 NPV: 86 800 000 SEK
7.5 MSEK/MW (-25%)	LCOH: 51.7 SEK/kg NPV: - 30 100 000 SEK	LCOH: 34 SEK/kg NPV: 21 000 000	LCOH: 32.5 NPV: 96 000 000 SEK
5 MSEK/MW (-50%)	LCOH: 43.65 SEK/kg NPV: - 22 800 000	LCOH: 32 SEK/kg NPV: 32 000 000 SEK	LCOH: 30.2 NPV: 105 100 000 SEK

When analysing the same parameters for 2020 year's electricity prices in table 13, one finds that power-to-gas can be profitable compared to the baseline scenario if the electrolyser costs drop to 5 MSEK/MW which is a 50% reduction compared to todays' costs. As with the 2018 case, the power-to-gas system generates more revenue than the baseline scenario but with significantly higher margins.

Table 13- Sensitivity analysis of Power-to-gas scenario - Low spot price year

2020 – Low spot price year			
Hydrogen retail price / CAPEX Reduction	**20 SEK/kg (-50%)**	**40 SEK/kg (0%)**	**60 SEK/kg (+50%)**
10 MSEK/MW (0%)	LCOH: 21 SEK/kg NPV: -12 200 000	LCOH: 24 SEK/kg NPV: 64 800 000 SEK	LCOH: 22.5 SEK/kg NPV: 141 700 000 SEK
7.5 MSEK/MW (-25%)	LCOH: 20.5 SEK/kg NPV: -1 600 000 SEK	LCOH: 20.5 SEK/kg NPV: 75 300 000 SEK	LCOH: 20 SEK/kg NPV: 152 000 000 SEK
5 MSEK/MW (-50%)	LCOH: 19.6 SEK/kg NPV: 4 600 000	LCOH: 17.8 SEK/kg NPV: 85 500 000 SEK	LCOH: 17 SEK/kg NPV: 162 000 000 SEK

5.2 Scenario 2: Power-to-Power

In the power-to-power scenario, where the hydrogen is used to provide back-up power and contribute to the frequency restoration reserve, the results were again analysed for electricity prices from 2018 and 2020. The results from both years show that this operational mode of the system yields significantly less operational hours than in the power-to-gas scenario. In the 2018 case, the fuel cell is active only 140 hours, generating a total output of 260 MWh electrical power. For 2020, the fuel cell yields an output 1750 MWh during a total 930 hours of operation. The difference between the two years can be explained by the large fluctuations in electricity prices in 2020. This results in more hours where hydrogen production can be done inexpensively and stored for hours where it is profitable sell extra power to the grid for up-regulating prices.

Figure 16 below shows an example of two days of operation of power-to-power system. In point 1, the optimizer activates the electrolyser due to a local minimum of the down-regulating price at which the power for the hydrogen production is paid. The yellow line that follows depicts at which hours the electrolyser is operating and fills up the hydrogen storage. Point 2 shows when the fuel cell is triggered due to a spike in up-regulating price. Its operation is showed by the blue line that follows and it can be seen that over a breakpoint price of 1 200 SEK/MWh, the optimizer prioritizes power production from the fuel cell.

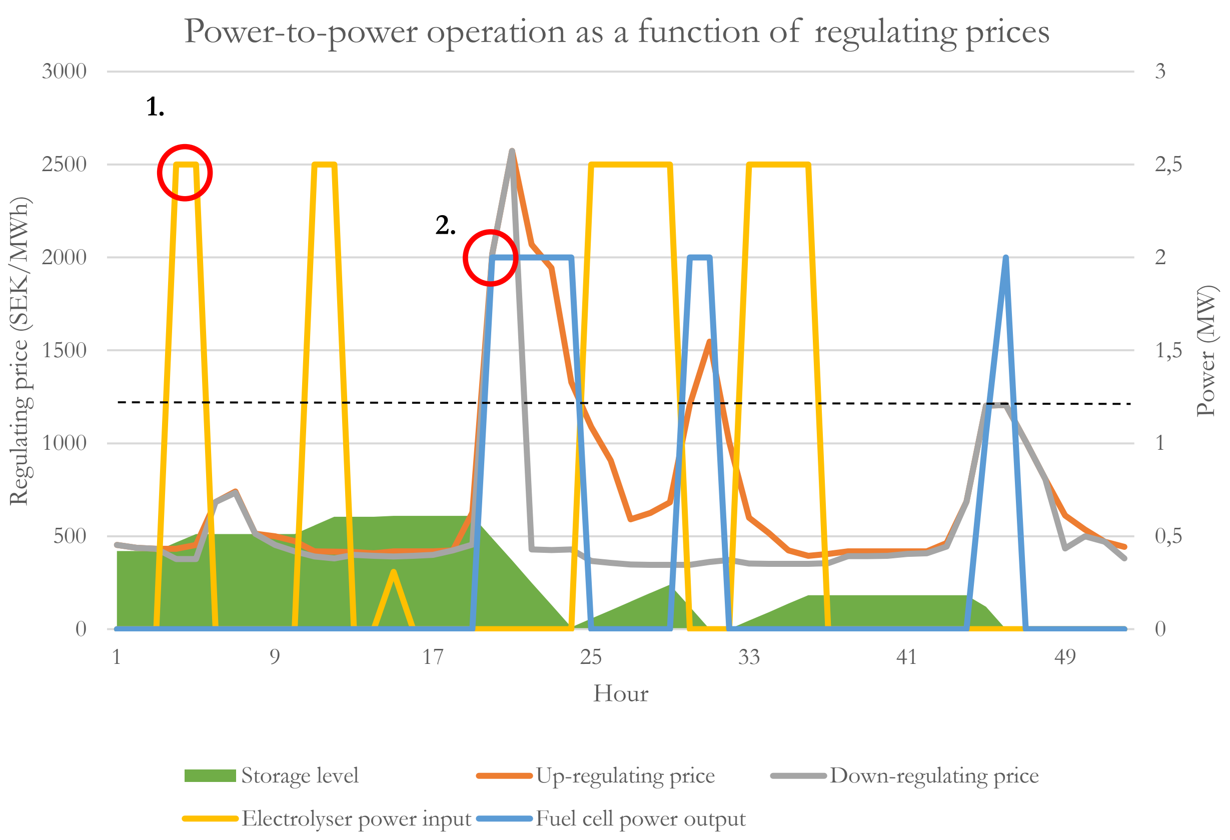

Figure 16 - Example of how the power-to-power system is operating as a function of regulating prices. In point 1, along the yellow line shows the operation of the electrolyser, which activates when down-regulating prices drop. Point 2 along with the blue line depicts the fuel cell activity, which is operational at up-regulating prices over 1200 SEK/MWh.

5.2.1 Economic impact

The revenue and cost streams in the power-to-power scenario differs considerably from the 2018 case the 2020 case, which is as mentioned a result of the regulating prices of the two years. As can be seen in table 14, the revenue streams from the 2020 case are larger due to more hours of operation combined with lower down-regulating prices and higher up-regulating prices. This makes it more economic to store electricity as hydrogen during down-regulating hours and convert it back during up-regulating hours. The analysis also considers the loss of revenue that would in the baseline scenario be generated by selling generated electricity on the spot market, as it is done today. In both cases, this loss of revenue is smaller than the net revenue from the Power-to-Power system, which results in a net positive economic impact compared to the baseline scenario. For the 2018 case, the net impact is 21 000 SEK and 158 000 SEK for the 2020 case.

Table 14 - Yearly revenue and cost streams of the PtP-system

Cash flows	PtP - 2018	PtP - 2020
Revenue from FC output (SEK)	297 000	1 437 000
Cost of electricity input (SEK)	47 000	360 000
O&M costs PtP-system (SEK)	49 000	330 000
Loss of spot market revenue compared to baseline (SEK)	180 000	520 000
Net economic impact of PtP (SEK)	**21 000**	**158 000**

5.2.2 Cost of Power-to-Power

In this scenario, the total costs of a power-to-power system are dominated by the investment costs of the equipment, where of the fuel cell and electrolyser makes up the main share. This can be explained by the few operational hours of the system, which makes the O&M costs small in comparison to the power-to-gas scenario where the electricity used for the hydrogen production was the main contributor to the life cycle cost. The analysis is based on the CAPEX costs of today, which amount to 15 MSEK/MW for a fuel cell and 10 MSEK/MW for a PEM electrolyser. These parameters are further examined in the sensitivity analysis, as they are expected to decrease in the coming years.

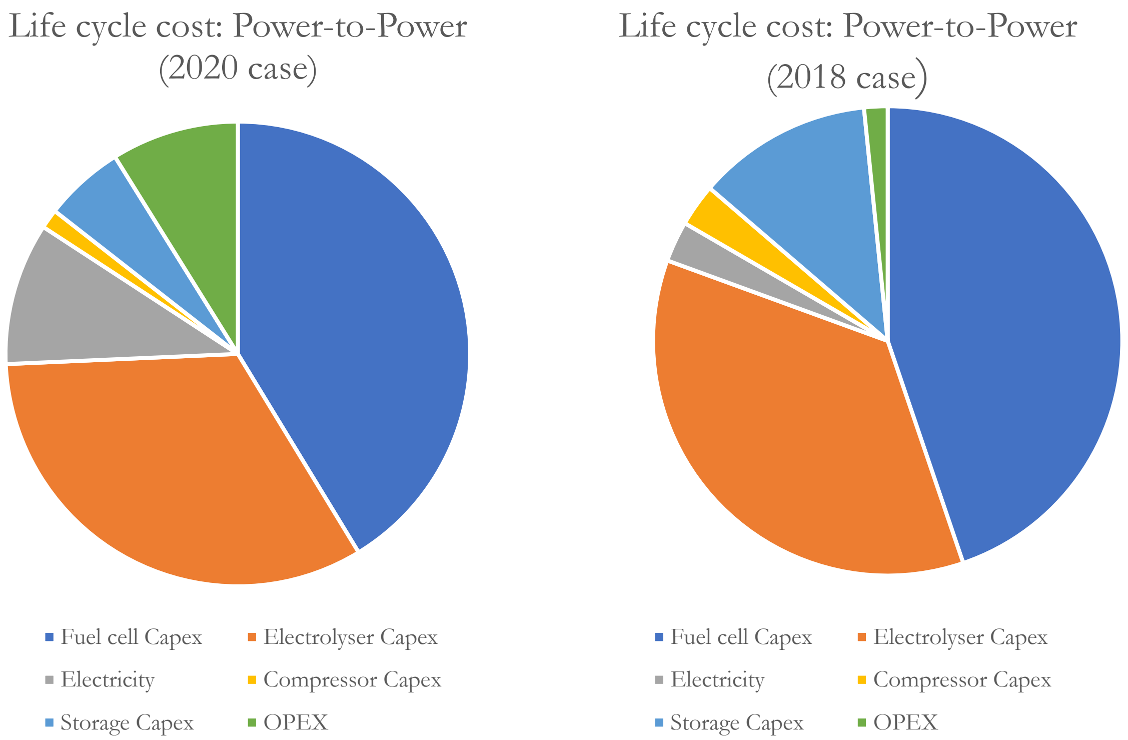

Figure 17 – Breakdown of life cycle costs of the PtP-system at for two examined years. Values are based on fuel cell CAPEX of 15 MSEK/MW and electrolyser CAPEX of 10 MSEK/MW.

5.2.3 Net present value

The results show that the investment will not be profitable for any of the studied years. With an annual economic benefit of 21 000 SEK for 2018 and 150 000 SEK for 2020, the investment cost of almost 60 MSEK will not be paid back during the 20 years lifetime of the system. With a discount rate at 5%, the NPV for the 2018 and 2020 case is -57 MSEK and -58 MSEK, respectively. The LCOE generated by the power-to-power system is calculated at 19 500 SEK/MWh for the 2018 case and 3 100 SEK/MWh for 2020.

5.2.4 Environmental impact

The reduction of GHG-emissions due to the Power-to-power system is calculated at 72 tonne CO_2-equivalents for the 2018 case and 419 tonne for the 2020 case. This is based on the assumption that the power generated by the fuel cell replaces marginal power during peak hours, when the carbon footprint of the electricity is high.

5.2.5 Summarized results: Scenario 1: Power-to-Power

Table 15 - Results - Power-to-Power scenario

Performance parameters	2018 – High price scenario	2020 – Low price scenario
Produced hydrogen	15.5 tonne H_2	104 tonne H_2
Fuel Cell output	260 MWh	1 750 MWh
Electrolyser operational hours	349 hours	2402 hours
Fuel cell operational hours	141 hours	929 hours
Saved CO_2 emissions	72 tonne CO_2	419 tonne CO_2
LCOE	19 500 SEK/MWh	3 100 SEK/MWh
Economic benefit	21 000 SEK/year	158 000 SEK/year
NPV	-59 MSEK	-57 MSEK

5.2.6 Sensitivity analysis – Power-to-Power

The sensitivity analysis for the PtP-scenario examines how the NPV and LCOE is affected by a reduction of capital costs of the most expensive components in the system – The electrolyser and the fuel cell. In the main analysis, the CAPEX used for the electrolyser and fuel cell was 10 MSEK/MW and 15 MSEK/MW. As mentioned in section 3.8, these costs are expected to decrease significantly in the coming years as the manufacturing rates ramp us along with the economics of scale that follows.

Table 16 show how the LCOE and the NPV change with a decrease in investment costs. It can be seen that even with CAPEX costs falling 50%, the power-to-power does not generate enough revenue to be economically justifiable.

Table 16: Sensitivity analysis of how the NPV and LCOE of the Power-to-power scenario change with CAPEX reductions of electrolysers and fuel cells for both examined years.

CAPEX (%) / **Year**	**-50%** Electrolyser: 5 MSEK/MW Fuel cell: 7.5 MSEK/MW	**-25%** Electrolyser: 7.5 MSEK/MW Fuel cell: 12.5 MSEK/MW	**0%** Electrolyser: 10 MSEK/MW Fuel cell: 15 MSEK/MW
2018 (high spot price)	LCOE: 10 600 SEK/MWh NPV: -29 MSEK	LCOE: 15 000 SEK/MWh NPV: -43 MSEK	LCOE: 19 500 SEK/MWh NPV: - 56 MSEK
2020 (low spot price)	LCOE: 1780 SEK/MWh NPV: -22 MSEK	LCOE: 2 2400 SEK/MWh NPV: -36 MSEK	LCOE: 3 100 SEK/MWh NPV: -50 MSEK

6 Discussion

In this section, the obtained results will be discussed and analysed against the background of the literature study. Lastly, a conclusion will be made of how the study's objective is met.

6.1 Validation of results

The results of the study show that a power-to-gas concept, where hydrogen is produced from an electrical power source and sold as a product, can be profitable option for a power plant operator. When the capacity factor of the power-to-gas system is high, as it is in the simulated cases, a levelized cost of hydrogen production can reach as low 20 SEK/kg. With retail prices of 40 SEK/kg and upwards, this yields a significant net margin in economic benefit. In such cases, the major cost parameter is the price of electricity which can be seen in the large difference between the LCOH calculated for 2020's and 2018's electricity prices. These results are in line with previous work by IRENA presented in section 3.8, who also conclude that the price of electricity is by far the most dominating factor for systems with more than 4 500 operational hours per year. IRENA also estimates a LCOH in the range of 20 to 30 SEK/kg at an average electricity price of 200 SEK/MWh.

Results from the power-to-power scenario also align with previous literature presented in section 3, where most reports agree on that the high investment costs required for power-to-power system outweigh the economic benefit of only supplying grid services. The lowest LCOE obtained in this study was found in the 2020 case, with just over 3 000 SEK/MWh. This is line with other reported LCOE from similar setups, reaching from 4000 – 6000 SEK/MWh.

6.2 Assumptions and model limitations

When examining the results of the simulation, one should take into consideration that several assumptions have been made due to either lack of proper data or to simplify the model. One of the main assumptions of the model is that it does not account for the dynamics of the district heating network, which is modelled as a fixed and resembles the production cost of the next facility in the merit order. In reality, this variable is varying depending on factors like heat load and fuel prices and was regarded too complex to model in the time-frame of the project.

Other assumptions that could have an effect on the optimization results were the efficiencies of the components which were modelled as constant. To build a more precise model, these should be modelled as load-dependent. Similarly, cost parameters like fuel for IKV were set as fixed, although they might vary over the year.

6.3 Implications for Söderenergi

Operational impact

The results from this study show that hydrogen production for a future hydrogen market is an option that could secure revenue on a market that is more stable than selling all power to the electricity market. This would in turn lower the production cost of district heat. The scale of the power-to-gas or power-to-power system presented in this study did however not have a significant effect on the operational mode of IKV in terms of heat production. With a hydrogen retail price of 40 SEK/kg, the optimization will choose to prioritize electricity for hydrogen production as long as the electricity price is below the breakpoint of 720 SEK/MWh, which is the majority of the hours of the year in both presented cases examined in this report. However, because of the small size of the electrolyser in comparison to the turbine and the condensers of IKV, it will not have the influence to favour back-pressure mode due to a minimum load of the turbine of 20 MW.

Profitability

It is clear that the price of electricity heavily influences the final cost of hydrogen production in a power-to-gas process. This indicates that the development of the electricity market should be studied and evaluated closely by Söderenergi. By current estimates, the electricity market is expected to become more volatile in the future along with lower average costs due to the expansion of intermittent power supply. With such development, the option of power-to-gas could become a promising alternative for an actor like Söderenergi. The business model could also increase Söderenergi's opportunities to provide balancing services by down-regulating the power production in times of high frequency in the grid. In this way, Söderenergi could generate additional revenue by delivering grid services while producing hydrogen for the market.

When it comes to the power-to-power business model, it is clear that the high investment cost does not pay off due to the low capacity factor even in a fluctuating year like 2020. This study has however only considered part-taking in the mFRR-market. Since both PEM electrolysers and fuel cells have been shown to regulate the in-and output within seconds, other regulating markets that require shorter response time than mFRR could be considered.

Storge & distribution

One issue that showed to be a limiting factor when dimensioning the power-to-gas system was available storage capacity. Hydrogen in gaseous form have relatively low density even at high pressures, which requires large storage tanks or a continuous or frequent distribution. In this project, a containerized tube-trailer solution was chosen to be a feasible option due to its flexibility and infrastructural advantages. This storage system does however take up a significant area which was found to be limited at the IKV facility. Since no other storage method was economically or physically viable, this put a limit to how much hydrogen could be produced on a daily basis. In a future where the hydrogen infrastructure is more built up, other forms of distribution could be considered, such as pipelines to closely located fuelling stations or industries. This would reduce both transport costs and the physical limitations of storage.

Environmental impact

Even though the electricity generated in IKV has a small carbon footprint due to the large amount of renewable fuel that is used, it does not reduce the overall GHG-emissions in the power system significantly as Swedish electricity already has a low carbon footprint. Hydrogen on the other hand has the potential of replacing fossil fuels in applications where electricity is not a viable option, such as maritime transport, long-range trucks or steel manufacturing. Söderenergi could therefore make a significant contribution in the reduction of GHG-emissions by producing hydrogen of the low-carbon electricity generated in IKV.

Waste heat

The utilisation of waste heat from the electrolyser and fuel cells is an interesting prospect that should be investigated further. In the components analysed in this study, the temperature of the cooling water is not high enough to be used directly in the district heating network. There are however other potential applications of this heat, for example by preheating the return water. The development of low-temperature district heat networks could however provide an opportunity of injecting into the network which would increase the efficiency of the system.

Green hydrogen market

One factor of uncertainty in this study is of course the development of the hydrogen market in Sweden. To successfully apply a power-to-gas model, a sufficient demand for hydrogen is a critical issue. Today, the demand cannot be said to be enough to justify a large investment like the one proposed in this thesis. But given the development of hydrogen-fuelled transport in several sectors, the demand of green hydrogen will grow fast in the coming years. Söderenergi should follow this trend closely and if possible identify consumers of hydrogen in the Södertälje area. Another important aspect is the certification system that guarantees the origin of green hydrogen. If Söderenergi will market the produced hydrogen as green, a collaboration with the CertifHY organisation could be important.

6.4 Conclusion

This study concludes that the concept of power-to-gas is technically feasible at IKV and could already be profitable given the electricity prices and investment costs of today. Also, the predicted development in the electricity market and CAPEX of electrolysers indicates an even more solid revenue stream from hydrogen production. This does however depend on a strong demand from the hydrogen market which is not readily available today. In the future, hydrogen used in the transportation sector is expected to grow in a fast pace and could generate enough demand by 2025.

Power-to-power is not a viable investment for Söderenergi today and will most likely not be in a near future, as the investment costs far outweigh the potential revenues. Even with volatile electricity prices as seen in 2020 the investment does not pay off. This indicates that with an increasingly volatile electricity market, power-to-power is not economically viable on its own.

Finally, green hydrogen production at IKV could replace a substantial amount of fossil fuels in sectors like transportation and industry and therefore help to decarbonize the society as a whole.

6.5 Future work and recommendations

Sweden, just like many places in the world is going through an energy transition that will transform many of the current systems of today. Therefore, it is important for an energy company like Söderenergi to follow the development of the various energy markets closely. In this project, the potential of hydrogen production at Söderenergi has been investigated party by developing a mathematical model that simulates the optimal performance of IKV. Due to constraints in time and limited access to standardized optimization tools like BoFiT, the model was built from scratch using the programming language Python. This does lead to certain limitations in terms of precision. The results should therefore be seen as indicators and recommendations of which areas to keep investigating. In the case of Söderenergi, following topics should be studied further:

- Develop a more complete model of IKV by for example by using BoFiT.
- Follow the hydrogen market closely and identify business partners for the selling and distribution of hydrogen, if possible in the Södertälje area.
- Collaborate with instances like the EU and Energimyndigheten for potential financial support.
- Keep investigating the potential of grid balancing by using electrolysers to restore over frequency.
- Investigate other technologies for hydrogen production and re-electrification than the components used in this study.
- Examine how the revenue from hydrogen affects the district heat production planning of IKV and establish methods to proactively decide the pricing.

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Appendix A

Model

Decision variable	Explanation	Unit
Q_{DC}	Heat from direct condenser	MW
Q_{BP}	Heat from back pressure condenser	MW
Q_{FGC}	Heat from flue gas condenser	MW
Q_{Fuel}	Fuel input	MW
$Q_{marginal}$	Heat from other plant in DH network	MW
P_{gen}	Electricity generated in IKV	MW
$P_{sell,grid}$	Electricity sold to grid	MW
$P_{Buy,grid}$	Electricity imported from grid	MW
$P_{electrolyser}$	Electrolyser power input	MW
$P_{fuel\ cell}$	Fuel cell power output	MW
$m_{H2,prod}$	H2 produced in electrolyser	kg/h
$m_{H2,cons}$	H2 consumed in fuel cell	kg/h
$m_{storage}$	H2 stored in storage	kg
$U_{fuel\ cell}$	Integer variable (on/off)	(0,1)
$U_{electrolyser}$	Integer variable (on/off)	(0,1)
U_{sell}	Integer variable (on/off)	(0,1)
U_{buy}	Integer variable (on/off)	(0,1)

Power-to-Gas

Objective of the DH-network: supply enough heat to always cover the demand.

$$Q_{DC}(t) + Q_{BP}(t) + Q_{FGC}(t) + Q_{marginal}(t) \geq Q_{demand}(t)$$

Production limitations

$$Q_{heat,min} \leq Q_{DC}(t), Q_{BP}(t) \leq Q_{heat,max}$$

$$Q_{FGC,min} \leq Q_{FGC}(t) \leq Q_{FGC,max}$$

$$P_{gen,min} \leq P_{gen}(t) \leq P_{gen,max}$$

Power generation

$$P_{gen}(t) = \alpha * Q_{BP}(t)$$

Energy balance

$$Q_{fuel}(t) = \frac{P_{gen}(t) + Q_{BP}(t) + Q_{DC}(t)}{\eta_{boiler}}$$

$$P_{gen}(t) + Q_{BP}(t) + Q_{DC}(t) \leq Q_{fuel}(t)$$

Power balance

$$P_{gen}(t) + P_{buy,grid}(t) = P_{sell,grid}(t) + P_{electrolyser}(t)$$

$$P_{buy,grid}(t) \leq P_{buy,max} * U_{buy}(t)$$

$$P_{sell,grid}(t) \leq P_{sell,max} * U_{sell}(t)$$

$$U_{buy}(t) + U_{sell}(t) \leq 1$$

Electrolyser

$$P_{electrolyser,min} \leq P_{electrolyser}(t) \leq P_{electrolyser,max}$$

$$m_{H2,prod}(t) = P_{electrolyser}(t) * \eta_{system} * unitconversion_{H2}$$

Storage

$$m_{storage}(t) \leq m_{storage,max}$$

$$m_{storage}(t) = m_{storage}(t-1) + m_{H2,prod}(t)$$

$$m_{storage}(t) = m_{storage}(t-1)$$

The storage is emptied every 24 hours.

$$m_{storage}(t) = 0$$

If spot price falls below the breakpoint of when FGC-production is the cheapest option, turn on the FGC. The heat extracted is proportional to the heat generated in the boiler.

$$Q_{FGC}(t) = Q_{fuel} * 0.22$$

If the spot price rises above the breakpoint, the FGC is not operational.

$$Q_{FGC}(t) = 0$$

The objective function minimizes the total cost of the system in the rolling horizon of T hours with a timestep of t hours.

$$\min \sum_{t=0}^{T} Q_{DC}(t) * cost_{DC}(t) + Q_{BP}(t) * cost_{BP}(t) + P_{gen}(t) * \left(cost_{gen}(t) - el_{revenue}\right)$$
$$+ P_{buy,grid}(t) * cost_{grid} + P_{electrolyser}\left((t) * cost_{PtG}(t) + el_{price}(t)\right)$$
$$- m_{H2,prod}(t) * H2_{revenue} + Q_{marginal}(t) * cost_{marginal}$$

Power-to-Power

Objective of the DH-network: supply enough heat to always cover the demand.

$$Q_{DC}(t) + Q_{BP}(t) + Q_{FGC}(t) + Q_{marginal}(t) \geq Q_{demand}(t)$$

Production limitations

$$Q_{heat,min} \leq Q_{DC}(t), Q_{BP}(t) \leq Q_{heat,max}$$
$$Q_{FGC,min} \leq Q_{FGC}(t) \leq Q_{FGC,max}$$
$$P_{gen,min} \leq P_{gen}(t) \leq P_{gen,max}$$

Power generation

$$P_{gen}(t) = \alpha * Q_{BP}(t)$$

Energy balance

$$Q_{fuel}(t) = \frac{P_{gen}(t) + Q_{BP}(t) + Q_{DC}(t)}{\eta_{boiler}}$$
$$P_{gen}(t) + Q_{BP}(t) + Q_{DC}(t) \leq Q_{fuel}(t)$$

Power balance

$$P_{gen}(t) + P_{buy,grid}(t) = P_{sell,grid}(t) + P_{electrolyser}(t)$$
$$P_{buy,grid}(t) \leq P_{buy,max} * U_{buy}(t)$$
$$P_{sell,grid}(t) \leq P_{sell,max} * U_{sell}(t)$$
$$U_{buy}(t) + U_{sell}(t) \leq 1$$

Electrolyser and fuel cell

$$P_{electrolyser}(t) \leq P_{electrolyser,max} * U_{electrolyser}(t)$$

$$P_{fuel\ cell}(t) \leq P_{fuel\ cell,max} * U_{fuel\ cell}(t)$$

$$U_{electrolyser}(t) + U_{fuel\ cell}(t) \leq 1$$

$$m_{H2,prod}(t) = P_{electrolyser}(t) * \eta_{system} * unitconversion_{H2}$$

$$P_{fuel\ cell}(t) = m_{H2,cons}(t) * \eta_{fuel\ cell} * \frac{1}{unitconversion_{H2}}$$

Storage

$$m_{storage}(t) \leq m_{storage,max}$$

$$m_{storage}(t) = m_{storage}(t-1) + m_{H2,prod}(t) - m_{H2,cons}$$

$$m_{storage}(t) = m_{storage}(t-1)$$

The storage is emptied every 24 hours.

$$m_{storage}(t) = 0$$

If spot price falls below the breakpoint of when FGC-production is the cheapest option, turn on the FGC. The heat extracted is proportional to the heat generated in the boiler.

$$Q_{FGC}(t) = Q_{fuel} * 0.22$$

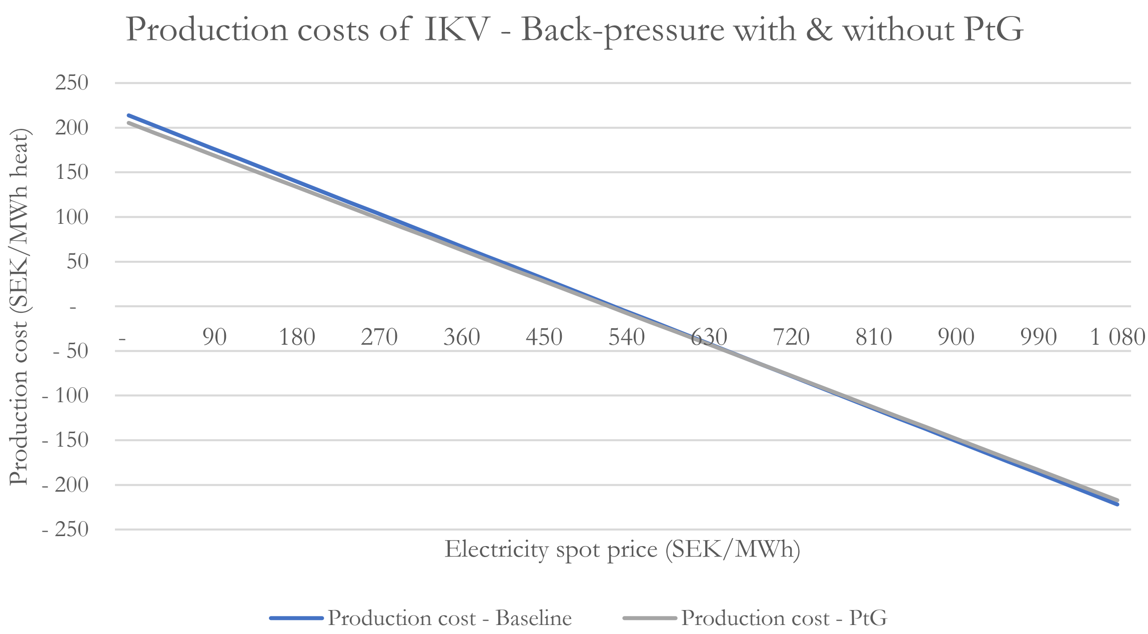
If the spot price rises above the breakpoint, the FGC is not operational.

$$Q_{FGC}(t) = 0$$

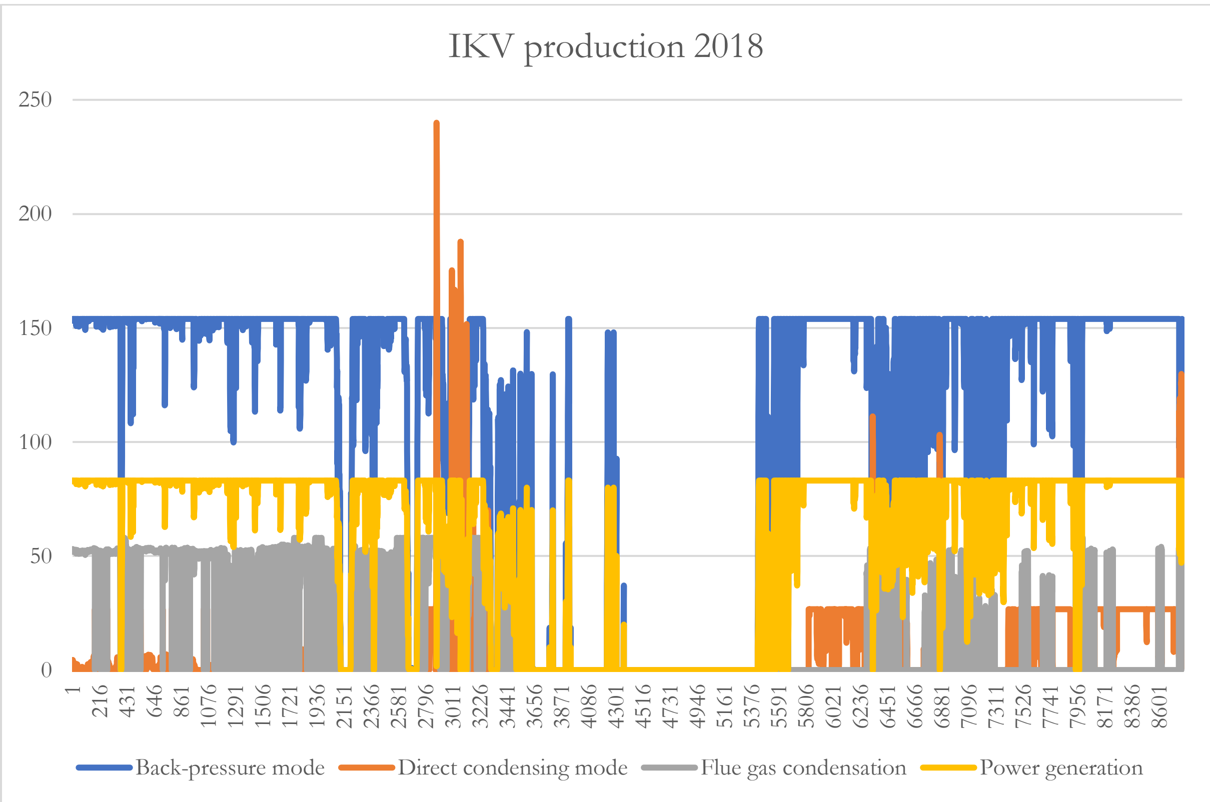
The objective function minimizes the total cost of the system in the rolling horizon of T hours with a timestep of t hours.

$$\begin{aligned} min \sum_{t=0}^{T} Q_{DC}(t) * OPEX_{DC}(t) + Q_{BP}(t) * OPEX_{BP}(t) + P_{gen}(t) * \left(OPEX_{gen}(t) - el_{revenue}\right) + P_{buy,grid}(t) \\ * OPEX_{grid} + P_{electrolyser}\left((t) * OPEX_{PtG}(t) + el_{price,down-reg}(t)\right) - m_{H2,prod}(t) * H2_{revenue} \\ + P_{fuel\ cell}(t) * (OPEX_{fuel\ cell} - el_{revenue,up-reg}) + Q_{marginal}(t) * OPEX_{marginal} \end{aligned}$$

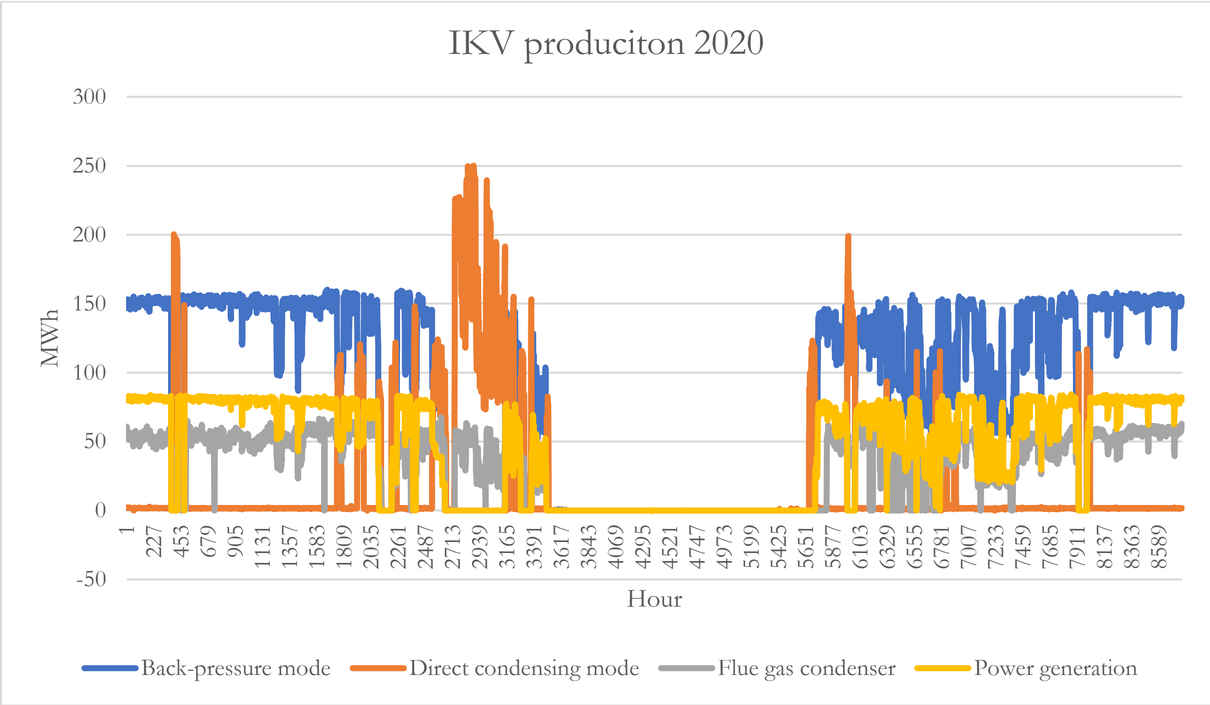
Appendix B



Production costs of IKV - Back-pressure with & without PtG
Production cost (SEK/MWh heat)
250
200
150
100
50
-
- 50
- 100
- 150
- 200
- 250
-
90
180
270
360
450
540
630
720
810
900
990
1 080
Electricity spot price (SEK/MWh)
Production cost - Baseline
Production cost - PtG



IKV production 2018
250
200
150
100
50
0
1
216
431
646
861
1076
1291
1506
1721
1936
2151
2366
2581
2796
3011
3226
3441
3656
3871
4086
4301
4516
4731
4946
5161
5376
5591
5806
6021
6236
6451
6666
6881
7096
7311
7526
7741
7956
8171
8386
8601
Back-pressure mode
Direct condensing mode
Flue gas condensation
Power generation


IKV produciton 2020
300
250
200
150
100
50
0
-50
MWh
1
227
453
679
905
1131
1357
1583
1809
2035
2261
2487
2713
2939
3165
3391
3617
3843
4069
4295
4521
4747
4973
5199
5425
5651
5877
6103
6329
6555
6781
7007
7233
7459
7685
7911
8137
8363
8589
Hour
Back-pressure mode
Direct condensing mode
Flue gas condenser
Power generation

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