Ole Einar Sætermo

The Value of DHN Heat Recovery for Hydrogen Energy Storage and Production

Case Studies of Grid-Level Energy Storage in the UK, and a Potential Hydrogen Fuel Production Facility for Express Boats in Norway.

Master's thesis in MIPROD
Supervisor: Håkon Jarand Dugstad Johnsen
Co-supervisor: Pedro Crespo del Granado, Wouter Koks
February 2024

Master's thesis

NTNU
Norwegian University of Science and Technology
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Preface

This is a master thesis for the Department of Mechanical and Industrial Engineering at NTNU, concluding a 2-year MSc. Engineering programme in product development and production.

My field of study as far as specialization subjects has been “the integrity of products” focusing on mechanical construction. However, the overall study program is very diverse in what it can encompass. This ranges from traditional mechanical engineering subjects to mechatronics to product development. The latter could be seen as quite an open-ended subject and would be what this thesis falls within. The thesis takes a basis in technical review and considerations and evaluates heat-recovery for H_2 energy through mathematical optimization.

In this case, heat recovery on Hydrogen technology is the technology/product to be reviewed. This was done on the basis of an interest about more potential frontiers with which to tackle the transition to renewable and inexhaustible energy sources. A thought from the beginning was to tackle this subject from a more technical/mechanical perspective, however, the focus ended up leaning towards a more economic point of view, while still retaining a technological component through technology review and energy-calculations.

I would like to thank my main supervisor Assoc. Prof. Håkon J. D. Johnsen for supporting me with positive, constructive, and encouraging feedback throughout both the specialization project and the master thesis. These two projects ended up being about different things, somewhat unusually for students at my department. Yet not outside of regulations. For advice regarding the areas around my chosen topic, I would like to thank Assoc. Prof. Pedro Crespo del. Granado. In addition to thanks for help with setting up fitting case studies and providing data (and methods of acquiring data) to run the mathematical optimization models on. The latter was also helped with by Research Assistant Wouter Koks, whom I would also like to thank for support with optimization modelling as well as various subjects regarding energy markets and the investigated (and envisioned) case studies.

For the thesis material, my hope is that the results can be informant towards decisions about future research (either academically or industrially) on Hydrogen technologies. Specifically, through highlighting the potential for improvement that including heat recovery can introduce in various scenarios.

Lastly, I would like to thank my family and close ones for patience and support through these years of studying.

Abstract

Hydrogen technology is often quoted as part of the solution when talking about the transition to renewable energy sources. However, as of now it has major downsides that hinders its adoption and its competitiveness. Mainly, this is its low associated efficiencies, and expensive hardware.

Major improvements are however expected in the coming decades, both in cost and efficiency. This thesis investigates the contribution that heat recovery (HR) can bring through district heating networks (DHNs), and to what degree this can increase performance for H_2 technology in two different contexts: Grid-level energy storage, and a fuel production facility.

The first: Large scale grid-level energy storage, will be necessary in the future along with the transition to non-dispatchable energy sources. While Li-ion batteries will likely dominate this space, it is still interesting to look into alternative methods, as filling the large global need for energy storage with batteries only raises questions regarding sustainability.

It was found that an H_2 energy storage and CHP (combined heat and power) facility would likely not be feasible around 2030. Component costs would have to drop considerably more than what is predicted to do by that time. However, if the circumstances does arise where it is economically profitable, it was found that adding heat recovery can increase performance by about 25%. This was found for a pessimistic heat price based on the equivalent cost of producing the heat with heat pumps. Which means that this 25% increase can be considered an absolute lower-end estimate. This could be a "make or break" addition for this potential application for H_2 technology, even if DHN heat-pricing is heavily reduced by policies.

For the transportation sector on the other hand, IEA reports that H_2 will stand for a sizeable share of aerospace and shipping energy, and batteries are not predicted to enter this space (except for a couple percents of total energy use). Here, it was interesting to investigate if recuperating energy costs through HR on fuel production could increase its competitiveness.

It was found, that for Joule-based heat pricing, the recuperated cost was slightly lower than the heat output share of total system energy-input including DHN losses. Ending up at 11% to 18%. However, for COP-based heat pricing, the case study found that the earnings were reduced to about 4 - 7% (depending on system efficiency). Although the latter scenario is quite pessimistic in regard to heat pricing, it was concluded that HR from electrolysis will likely not be a very decisive economic factor regarding H_2 fuel production. But it was found that it would likely warrant its own cost of implementation by a comfortable margin, both from economical and societal perspectives.

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Terms and abbreviations

Abbreviation	Meaning
HR	Heat Recovery
HESS	Hydrogen Energy Storage System
RES	Renewable energy sources
Supply-demand operations	Measures taken to balance energy supply and demand
VRF Batteries / VRFBs	Vanadium Redox Flow Batteries
SSB	Solid State Batteries
DHN	District Heating Network
DH5.0	5^{th} Generation District Heating
CHP	Combined Heating and Power
DHW	Domestic Hot Water
LP	Linear Program
OR	Operations Research
FC	Fuel Cell
HP	Heat pump
COP	Coefficient of performance
BOP	Balance of Plant (Everything required to run the system excluding the generation unit)
CAPEX	Capital Expenditures (Initial investment)
OPEX	Operating Expenditures (Energy, maintenance etc.)

1 Introduction

1.1 Fundamental background

As measures will be taken to mitigate climate change, there will be a large “energy transition” from fossil fuels to renewable energy sources. These energy sources are non-dispatchable. We cannot release their energy at the time of consumption (as with coal, gas, and hydropower etc.).

Figure 1-1 below shows Shells prognosis for the future global energy need by power source. It indicates that eventually solar and wind will constitute roughly half of produced energy world-wide. Naturally, this will vary by country, and the share of non-dispatchable energy sources will be higher in some countries, and lower in others (w. examples/details in section 2.1).

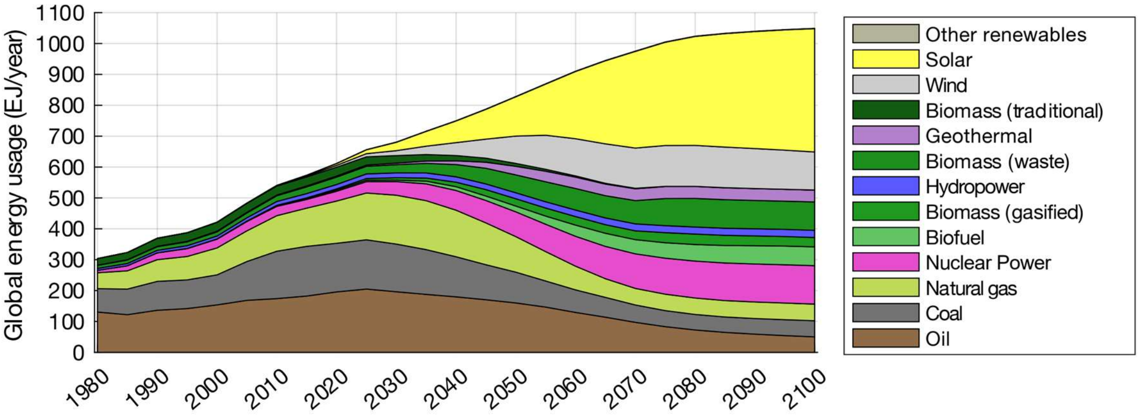


Figure 1-1: Shells prognosis for global energy need. Data aggregated from Shell's Sky Scenario. Image Credit: Lecture by Håvard Karoliussen for the course "TFNE3007 Renewable Energy" at NTNU. [1]

Once non-dispatchable energy sources (e.g., solar and wind) becomes dominant in the power generation sector, this will bring with it a need for large scale energy storage, in order to balance supply and demand. Supply equalling demand at all times, is a requirement for a functioning power grid. The exercise of ensuring this, is called “supply-demand operations”. The IEA (the International Energy Agency) states that a rapid scale-up of energy storage is critical in a decarbonized electricity system” [2].

As of today, pumped hydropower is the most widely used method for grid-level energy storage. However, its potential is limited and geographically restricted. IEA state that (electrochemical) “batteries are the most scalable type of grid scale storage and has seen strong growth in recent years”, and, they are “catching up to pumped hydro” [2]. They mention that other technologies include gravitational and compressed air, but that they “play a small role in current power systems”. Hydrogen is mentioned as an emerging technology with “potential for seasonal storage”. As for the state of progress, they say:

> *“While progress is being made, projected growth in grid-scale storage capacity is not currently on track with the Net Zero Scenario and requires greater efforts [2].”* *“While progress is being made, projected growth in grid-scale storage capacity is not currently on track with the Net Zero Scenario and requires greater efforts [2].”*

In addition to a transition in energy sources, one of the more challenging frontiers for a decarbonized energy sector, is the transportation sector. Here, development is happening rapidly, for example by li-ion battery-based passenger vehicles. However, in some areas of transportation, they are not technologically suitable (See section 2.2 for details and sources).

Both when it comes to energy storage and transportation, li-ion batteries will be a large/dominant part of the solution [2]. However, as will be discussed, some issues arise in certain scenarios regarding sustainability regarding energy storage. And for transportation, they will not be technologically feasible for the most energy-intensive applications.

The idea for this thesis, stems from a desire to look into alternative solutions to solve these problems. In particular, hydrogen will be considered. However, a downside of H_2 technology is its low efficiency compared to batteries. A way to partly remedy this, would be to utilize the significant heat by-product.

This thesis will study the effects recovering and utilizing the heat by-product from hydrogen production and consumption, in order to assess its impact. The central question of the thesis, becomes:

To what degree can recovery of the heat by-product remedy the low efficiency of hydrogen technology?

This will be investigated in an economical sense. The efficiencies themselves are well researched and published. But to what degree they affect system performance economically, less so. In this thesis, the measure for the contribution of HR is defined as:

$$\Delta K_{energy.HR} = K_{energy.no.HR} - K_{energy.w.HR} \qquad (1\text{-}1)$$

Where $\Delta K_{energy.HR}$ is the change in money spent on energy, by implementing heat recovery (HR) on the system. The right-hand side K values being the expenditures on electrical energy without and with HR respectively. The "contribution of HR", is the difference between the total energy cost for a system without HR, and one with HR.

This must however not be mixed up with overall "system performance", which in the case of energy storage, is the profits from selling energy for more than it was bought for. How much this value is changed by adding HR, is treated as the "contribution" of heat recovery, or the "value" of HR.

This will be investigated for two types of applications. The first being energy storage, and the other being hydrogen production for the transportation sector. Each described further in sections 1.2 and 1.3.

For each of these applications, three representative years of pricing variations will be examined, to establish effect this has for each application. The two applications are however different in this regard. Low pricing variation is for example detrimental to an energy storage system, but not as directly important for the value of HR in fuel production.

The hydrogen technology also will be examined in two different states. "Predicted peak 2030 efficiencies" will be used in one case, but "peak 2023 efficiencies" will also be examined. The latter both represents how today's technology would perform and gives a more conservative outlook on achievable efficiencies. It is also simultaneously meant to give an impression of how 2030 hardware will perform after years of service when its components has degraded. H_2 tech, much like batteries, degrade based on throughput and cycling over the years. Which increases the importance of HR towards their end of life.

1.2 Background on energy storage, and H_2 storage and CHP introduction

While batteries are predicted to be the dominant technology in this space, it also has some drawbacks. Lithium-ion batteries are the preferred battery type for grid-level storage at the time of writing [2]. However, a very large increase in demand for these batteries will put a strain on supply chains and bring with it challenges when it comes to the sustainability of their production, as well as their inevitable recycling or disposal. The mining of battery raw materials have large sustainability/climate impacts, and recycling them is difficult [3], [4], [5].

This provides a motivation to explore alternative technologies that may off-load the amount of li-ion batteries needed to be produced in the future.

One future option for this is flow batteries. A potentially promising option among these is VFR (Vanadium Redox Flow) batteries. Reasons include their ability to de-couple power and storage capacity, potentially higher cycles lives and potentially advantageous in sustainability and cost-efficiency for certain applications [6]. They are however yet on a research stage, so how well they can achieve such characteristics is to be seen in the future.

A weakness they have is lower round-trip efficiencies than Li-ion (Lithium-ion) batteries. Li-ion batteries usually have round-trip efficiencies around or above 90% (at beginning of life, before degradation) [7], [8, p. 5]. The efficiencies of VFR batteries vary greatly according to different sources, but kW-class systems are stated to achieve a round-trip efficiency of 57 – 75% [6].

Another potential option is H_2 storage. This option has an even lower round-trip electrical efficiency (ref. section 4.2.6). However, H_2 has a better potential for heat recovery. H_2 components have higher operating temperatures, for example around 80°C. Whereas a VFRBs operate effectively at temperatures of 10 to 40°C [9].

What this thesis will focus on, is to what degree heat recovery for an H_2 energy storage and CHP system can compensate for its low electrical round-trip efficiency. How much it will increase its performance, so that this may be taken into account when comparing it to VFRBs and Li-ion in the future. This is not as straightforward as finding out the round-trip efficiency. It will be a study where the economic performance of the system will be evaluated across different example years of electricity pricing, and also considering the value at which the recovered heat is sold. More on this below after presenting the layout of the system.

An H_2 Energy Storage System, would consist of an electrolyser (splitting water into hydrogen and oxygen), a compressor (optionally, but likely necessary, to avoid oversized tanks), hydrogen storage tanks, and a hydrogen fuel cell (producing electricity from the stored hydrogen). In this case, both the electrolyser and fuel cell would have a significant loss of energy to heat.

Research demonstrates that a large portion of this heat energy can be recovered using water as a medium [10], [11]. The energy flow of such a system is shown in Figure 1-2 below. This is what will be referred to as a “Hydrogen storage and CHP system”. It may also be referred to as a HESS (“Hydrogen Energy Storage System”) throughout this text.

The most promising hydrogen technology on the market today, revolves around proton exchange membrane (PEM) technology. With PEMEL (PEM electrolysers) and PEMFC (PEM fuel cell) devices respectively. As of the time of writing, examples of these technologies demonstrate electrochemical and electrical efficiencies of 63% and 56% respectively.

The round-trip electrical efficiency of an energy storage system based on these components could be as low as 31% with 2023 components (ref. section 4.2.6). However, with heat recovery, sources claim it could be increased again to around 95% one-way efficiencies for the electrolysers and fuel cells respectively [10], [11]. While most sources mentioned figures in this area, this does however not paint the full picture. As case study results will present, the true RTE (round trip efficiency) is considerably lower. It includes additional losses such as BOP (Balance of Plant: Everything required to run the system excluding the generation unit) for the electrolyser, compression energy and DHN (district heating network) losses. More so, the 95% efficiency with HR that is quoted for fuel cells, is for the LHV (lower heating value) energy contents of H_2. Which are 15% lower than the HHV (higher heating value) H_2 output of the electrolyser.

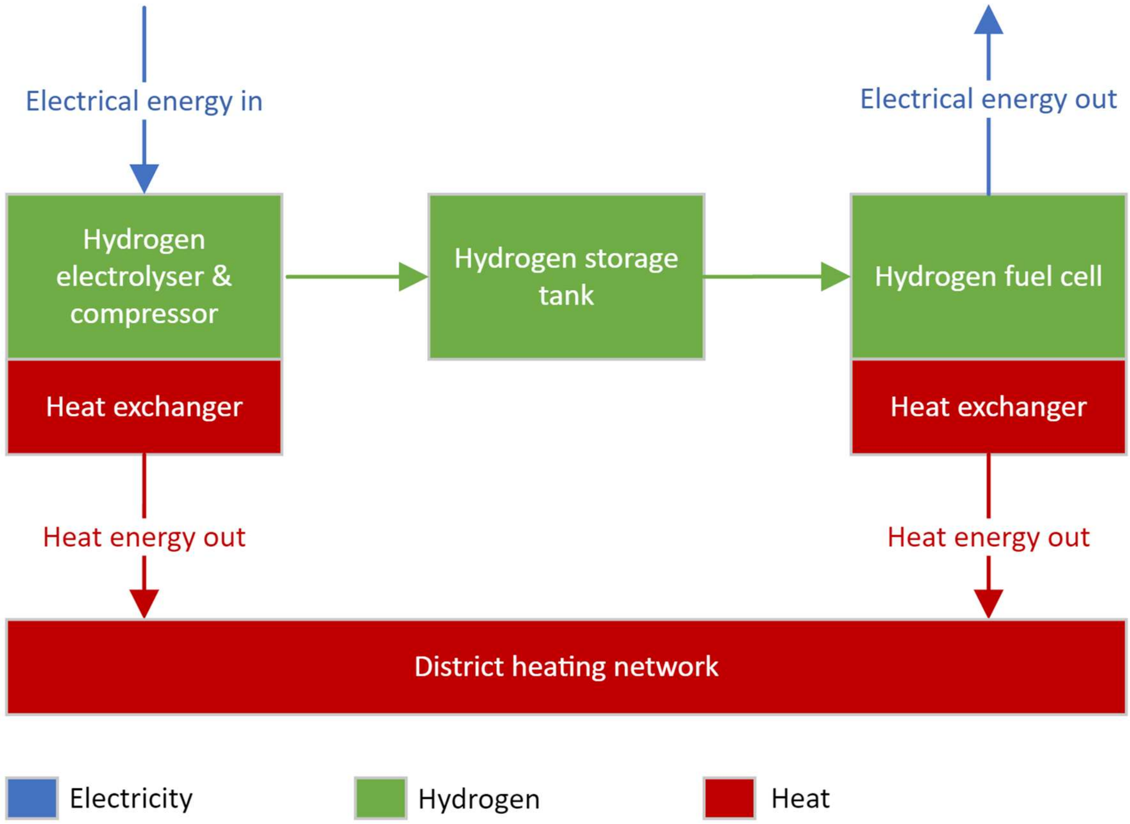


Figure 1-2: Hydrogen energy storage and CHP. (Simplified/basic layout)

The electrical round-trip efficiency itself of H_2 components is however predicted to increase significantly. (Section 2.5-2.8 contains a detailed review of H_2 tech. with sources). Electrolysers increasing their already high efficiency by 11%, and fuel cells increasing theirs by 20%. (Sources and calculations on efficiencies are found throughput, in section 2.5 - 2.7, 4.2 and Appendix B.)

Many countries have a majority of energy demand going towards heat (e.g. the UK with 80% of domestic energy usage being heat) [12]. This means there is ample room for utilization of this heat by-product, with the notable exception of summer months.

However, even if an H_2 system can greatly increase its round-trip efficiency through HR, a major set-back for the value of this heat by-product, is that heat can be acquired more efficiently or "inexpensively" if the energy is in the electrical form (e.g., with batteries). This is through the use of heat pumps, for which one can put e.g., 1 kWh electrical in, and get 3 kWh of heat out. This has major implications of the value of recovered heat and is something that will be investigated, on the basis of suggested pricing policies for DHN heat.

To what degree the heat recovery can remedy the low efficiency of hydrogen technology, then becomes a complex question depending on several factors. Such as heat pricing (linked to the varying COP of heat pumps), the available heat uptake potential, what capacities can be afforded for a certain CAPEX (initial capital expenditure on components), and how well these capacities can be adapted towards the available price-fluctuations on electricity.

Adapting system capacities to an optimal configuration is relevant to the system's ability to achieve good performance, as well towards how high the contribution of HR will be. The effect of the latter is not necessarily large, but it is noticeable, and its extent is varying.

As mentioned, the single, simple measure of the systems performance will be the profits, or the "money saved". Earnings from selling energy, minus the expenditure of storing energy. It can also be viewed as the "money saved" in terms of the total energy expenditure of the district itself. Since the H_2 system is connected to a certain district through a DHN, the usefulness of the system can be presented as the profits, divided by the total would-be energy costs for that districts without any storage.

This thesis will however not lay out any market considerations around how such a system might work. The goal here is to find the performance potential of the H_2 technology in this application, and how much HR increases it. Whether it is viewed as "money saved" or "profits" is arbitrary for this purpose, but due to how things were imagined around this in the early stages of the projects, performance might be referred to as both "money saved" or "profits" throughout this paper.

The performance by this measure is a proxy for how useful the system is, when it comes to future needed supply-demand operations. This is an interpretation from that variations in electricity-prices themselves are a proxy for supply vs. demand.

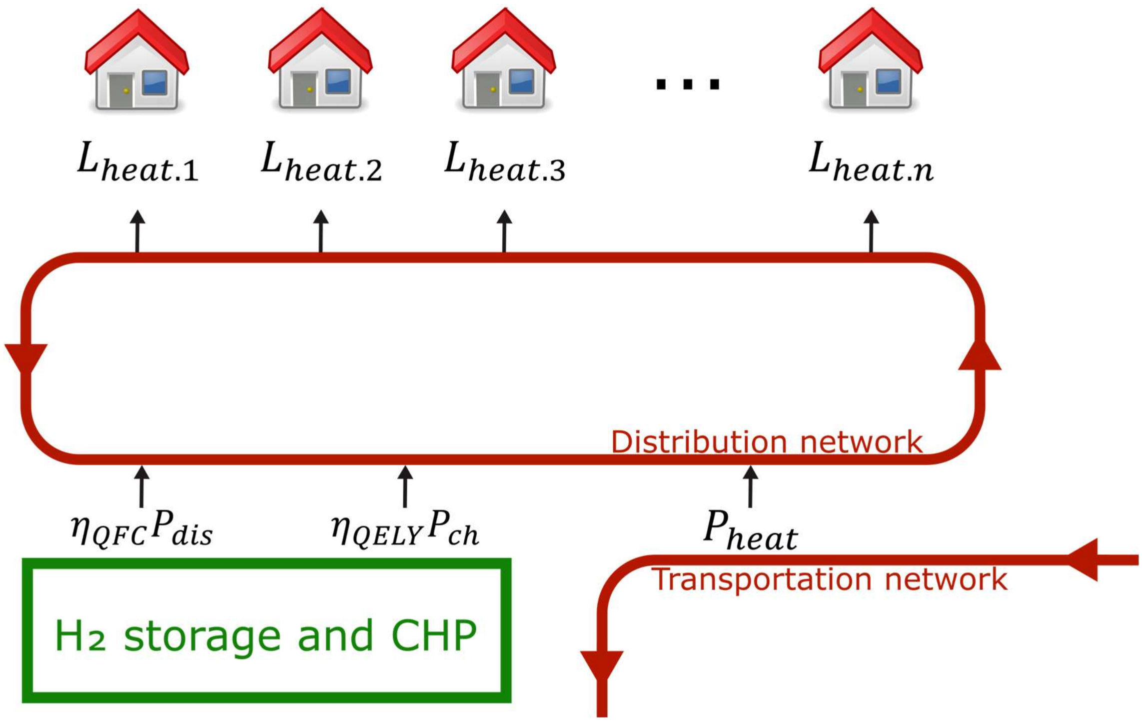


Figure 1-3: DHN layout for case 1. Credit for "House icon" SVG-file: OpenClipart [13].

The way the model will quantify this performance, is by setting up a case study where the system serves a district, which it is connected to by a district heating network. Specifically, a "distribution network", which is a sub-network of the full city-scale network. This will be the first case-study of this thesis. The "money saved" will be found for the HESS, and the results with and without HR being implemented will be used to determine the "value of HR" or "HR contribution".

What will be modelled to obtain these results, is the "distribution network" visualized in Figure 1-3 above. Noting, that the figure is only showing the DHN/heat part. Electricity is also included, but now shown in the figure to keep things un-cluttered. The optimization model will consider the energy flows to the houses, from the HESS as well as the electricity grid and DHN transportation network.

The envisioned scenario for this case, is a future setting in the UK as the nation goes towards a zero-carbon by 2050 goal. Reasons for this include its expected high future share of non-dispatchable energy generation, and thus high variability in electricity prices, coupled with its high heating demand and good prospects for DHN adoption. (See section 2.1.1 for details including sources). This makes it a highly relevant location for such a system.

1.3 Background for H_2 in the transportation sector and intro to second case study

One part of the energy sector that will be a challenge to decarbonize, is the transportation sector. Batteries will also be dominant in certain parts of this sector, and are starting to show success for example in electric passenger vehicles [14]. However, for some of the more energy intensive transportation applications, batteries are not capable of delivering the required performance in the foreseeable future. IEA presents in their "Net Zero Roadmap" that H_2 and H_2-based fuels (e.g. Ammonia) will stand for 63% of shipping energy and 37% of aviation energy in 2050, while they anticipate "electricity" standing for 3% of energy use in this space [15].

Solid state batteries can however potentially change the prospects for batteries in some select high-energy applications. This includes the application considered in the second case study of this thesis, which is passenger express-boats. SSBs does however have a very long expected way towards being ready for mass market adoption, and to what degree they will allow batteries to become capable for various energy-intensive applications remains to be seen. Due to their possible interference with the relevance of case 2 though, they will be discussed in detail in section 2.3.2.

In general, however, batteries struggle to keep up in highly energy intensive tasks. These applications, include various forms of shipping, aerospace, and long/heavy haul cargo trucks [16], [17], [18], [19]. In general: Transportation types that have high sustained power requirements, where high weight is a large disadvantage, and especially where frequent charging or switching of batteries is unfeasible or undesirable.

Hydrogen on the other hand, provides very high energy densities, making it suitable for these applications. It is thus mentioned as a leading option for their decarbonization [16], [17], [18]. However, H_2 as fuel lags far behind in market adoption compared to batteries. Reasons include pricing of hardware, and in some cases possibly safety considerations too. But a major reason, is the inefficiency associated with hydrogen components. A relatively small part of the energy put into H_2 can be utilized, compared to batteries. This raises the cost of fuel production, and the total energy amount that is needed.

As mentioned, both cost and efficiency performance for H_2 are expected to improve. Fuel cells will have the highest relative improvements, making H_2 powered vehicles more efficient. Electrolyser on the other hand are quite efficient, but their efficiency also drops with degradation over their lifetime. It is thought, based on later findings (Ref. sections 2.5 - 2.8, 3.3 and Appendix B) that HR will remain relevant for them for the foreseeable future.

On the background of this, this thesis will look at the role heat recovery can have in reducing the cost of hydrogen production. The motivation for this, is that it might contribute to lowering the adoption threshold for hydrogen production.

This will be done through a case study, regarding a express boat route in Norway for which H_2 boats were considered (as the only zero-carbon alternative) in 2024. The H_2 options were however not chosen. It was found interesting to examine what degree HR could lower fuel production costs towards for the next express boat contract in about a decade (or longer).

Figure 1-4: Aero. Hydrogen fast ferry concept by "Brødrene Aa" in 2019. Image Credit: Braa.no [20].

Norway can also be seen as a likely place for early H_2 adoption in general, due to historically cheap and clean electricity, and political forces that are likely to emphasize the decarbonization of the transportation sector. Which is one of the country's energy sectors with a high share of non-renewable energy. In contrast to their very low carbon electricity production and domestic energy sectors [21], [22].

The case study will look at how heat recovery of H_2 production could contribute to the potential decarbonization of passenger express-boats in central Norway. It will quantify the energy expenditure of a potential large-scale hydrogen production facility, and to what degree heat recovery can decrease this.

Hydrogen boats (Figure 1-4) were considered for the express-boat route in a 2019 proposal for the 2024 contract. But diesel-electric hybrids that still retain a pollution rate per passenger-km higher than flying were chosen. Reasons H_2 was still not chosen despite being the only zero-carbon option, may include considerations around H_2 production.

This thesis aims to quantify the contribution of heat recovery, in case it may be a relevant consideration towards the announcement of the next speed boat contract in about a decade (or more). At which point, transitioning to using H_2 as fuel might be a more valid option than it was in 2019. The energy flow in a fuel production facility with HR is illustrated in Figure 1-5 below.

An early idea in the project, was to consider the combination of a HESS and a fuel production site into a combined facility. This would be an interesting combination, regarding only the fuel cell with HR and optionally some more storage would need to be added onto the already existing H_2 production facility. While this is an interesting proposal, it was however chosen to look at either application by their own for this thesis.

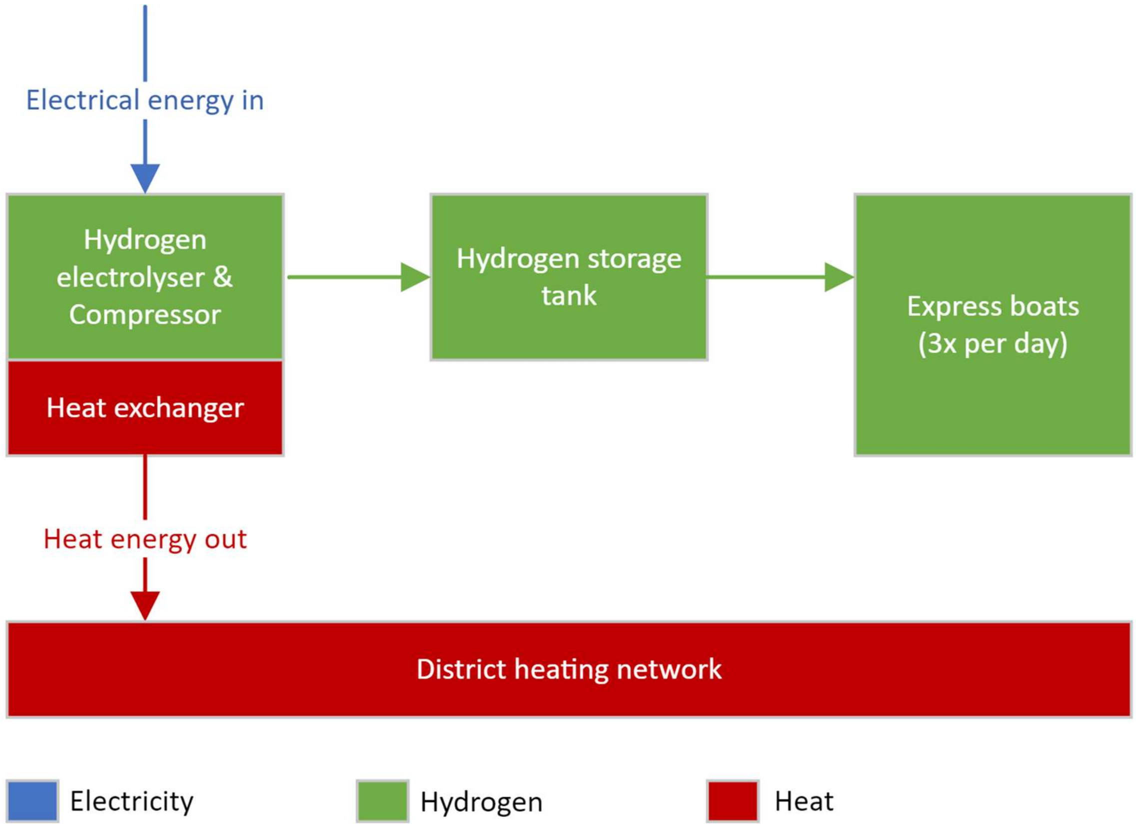


Figure 1-5: Energy flow for case study 2

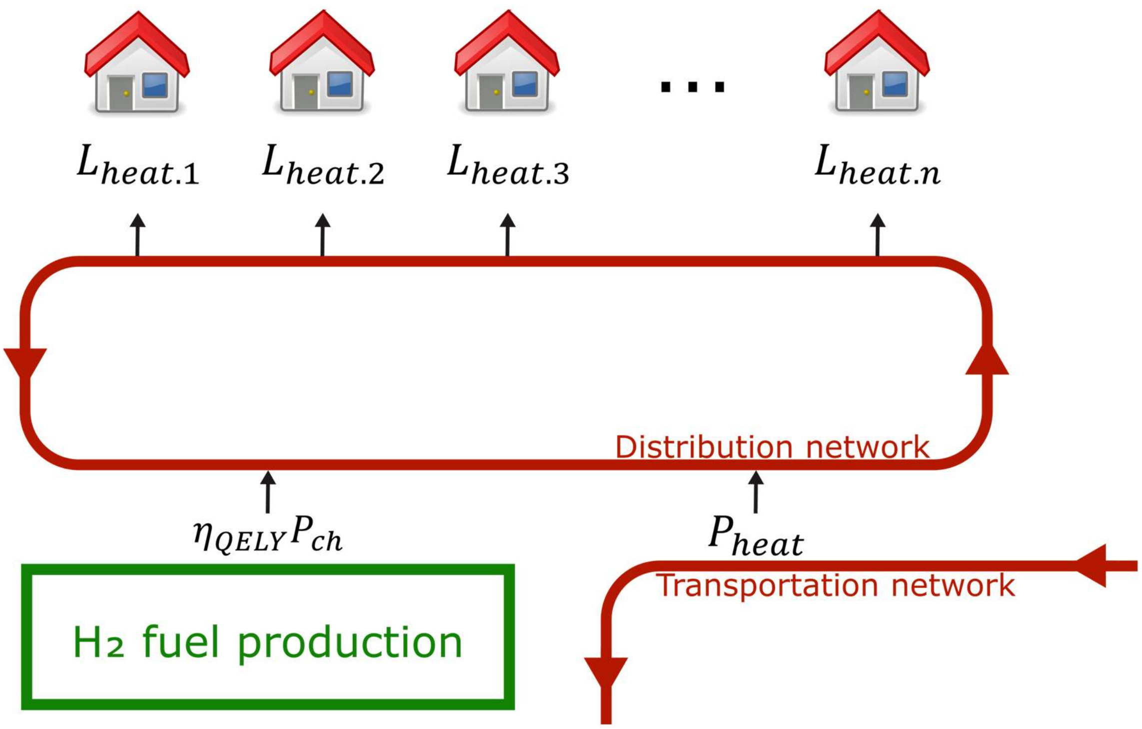


Figure 1-6: DHN of Case 2.Credit for "House icon" SVG-file: OpenClipart [13].

1.4 Scope of the thesis and the case studies

As mentioned, the scope is to find the contribution of HR, for the two different H_2 applications.

The underlying motivation for the thesis, is the question whether H_2 technology can possibly be competitive economically, or in terms of sustainability, compared to batteries. And thus, whether they can be a valuable contribution towards implementing a zero-carbon energy sector.

However, this would a very large area of work, including in depth technological analysis, LCA studies and much more, over a large span of technologies and fields. In order to narrow down the thesis, it was chosen to focus on the "value of HR" alone. In short, the thesis will provide performance results for the H_2 systems, with emphasis on "difference in performance by adding heat recovery".

Importantly, it is hard to judge this as future heat pricing schemes for DHN is hard to predict. Thus, the thesis will provide the above in two scenarios on this front. There will be a worst-case scenario, where heat pricing is heat pump based. I.e., based on the cheapest alternative method of acquiring heat. Then there will be a best-case scenario, where heat pricing is based on resistive heating.

Neither of these are however completely realistic. Resistive heating-based heat-cost (which for example is used in Norway today) is likely to be rendered un-competitive by heat pumps. But heat cost reduced to the equivalent of acquisition by heat pump, is also not seen as fair by DHN providers, as the cost of acquiring a heat pump itself should be taken into account, for example with some kind of DHN grid tariff [23].

The thesis will not answer these market questions (which is up to policymakers). But the worst case and best-case scenario will be presented in order to give an overview of the impact that heat costs lowered by heat pump COP would have to the value of heat recovery.

In addition to finding the HR contribution for different heat prices, the results will also be presented for different electricity-prices, and for different states of H_2 technology, in order to give a complete picture for the value of HR, depending on varying factors.

This will be done for both a HESS (Hydrogen Energy Storage System), and for a hydrogen production and fuelling facility. This will be case-study 1 and 2 respectively. Lastly, a conclusion will be made regarding the importance of HR in each scenario.

The scopes of the individual case studies are stated below.

1.4.1 Scope of the first case study

The scope of the first case study is as follows:

- Establish what H_2 component tech. that is likely to be used for this application.
- Establish and calculate efficiency levels and heat recovery ratios for H_2 components, including compression energy and BOP-losses. For both 2023 and 2030 states of tech.
- Implement a linear optimization model for the charging/discharging behaviour of such a system, that returns the "money saved" of the system. And find realistic parameters (data) and circumstances around which to set up the model.
- Establish cost estimates/functions for all throughput-related components (electrolyser, compressors, storage tanks and fuel cells).
- Implement a method/algorithm to automatically find an optimal combination of system capacities, based on which capacity configuration performs best for a given (constant) CAPEX. This optimal configuration is considered a "realistic/relevant" one to find the HR contribution for.

- Use the model and capacity optimization algorithm to find the theoretical performance roof for the H_2 system, with and without HR.
- Present the results (with emphasis on the delta between HR and no HR), for a range of relevant scenarios.

The above will be done for a range of scenarios. The multitude of which may be a bit overwhelming to keep track of. But in short, the following will be considered:

- Two different pricing regulations for DHN heating. Joule-based and COP based. These will be presented separately. Within each of these, the following will be presented.
- Three pricing years. 2019, 2022 and 2023. Relative to each other, these represent low, high, and medium price-volatility.
- Two states of H_2 technology. Peak 2030 efficiencies, and peak 2023 efficiencies. The latter also representing what a degraded 2030 system can look like.

One thing to point out here, is that *all scenarios* will have *their own* optimized set of *system capacities*. Each result for case 1, will represent the optimal H_2 system for that specific scenario. This is because the scenarios are thought to represent different future energy market states. 2019 is represents relatively stable pricing. 2022 represents high seasonal variation. And 2023 has high monthly/daily variation while somewhat frequently dipping below zero.

The scope is also limited when it comes to the actual degradation of the H_2 system. Degradation of batteries is well researched, but H_2 components less so (especially in the type of operation that it does here). Their component lifespans are quite high but start/stop cycling poses negative effects (ref. sections 2.5-2.7). However, it was considered “too large a scope” to include modelling that here. Instead, two reference points (2023 and 2030 efficiencies) were examined instead.

A direct comparison to Li-ion systems in the results will not be or emphasized, as it was not found feasible to do an in-depth “apples to apples” comparison with the time and resources at hand. But comparable Li-ion systems will be introduced in the theory chapter, and their results (in the optimization model) will be shortly mentioned.

1.4.2 Scope of the second case study

The scope of the second case study differs somewhat. It goes as follows:

- Establish an updated fuel requirement of the express boats for ~2035.
- Establish the technology to be used in the H_2 production and fuelling station and find/calculate the heat by product ratio.
- Implement a version of the linear optimization model for this case, find suitable parameters for it, and establish reasonable parameters and assumptions around the case.
- Establish a realistic set of system capacities for the H_2 facility.
- Find the savings on energy costs for fuel production that sale of heat energy can recover.
- Do this for the same range of scenarios as case 1: Two heat-price policies. Three pricing years, and for 2030 to 2023-levels of efficiency.

Early in the thesis, a more in-depth analysis of the mechanical side of things, was also considered. This included analysing the heat flow in an electrolyser (of which there would be several types to analyse, for some of which there was little research/information to go from). And, using the optimization model charge-state results as a basis for a FEA fatigue life analysis on the tanks etc.

However, it became clear that all of this would make the thesis scope too large/wide, and also be a bit off-topic, with the main focus of the thesis being HR. So, this fell out of the scope and into further work.

1.5 Limitations

The somewhat dual nature of the thesis (H_2 technology review + optimization modelling), to some degree hampered the depth gone into each area.

If the thesis was more purely optimization modelling, a more advanced implementation of the DHN efficiency could for example have been attempted. If the thesis was more focused on the mechanical side of things, then maybe a more in-depth physical approach to the analysis of energy flows for components, including looking at more types of electrolysers (such as SOEL) could be done. However, a compromise had to be done to make the scope achievable.

Another thing that was somewhat limiting, was not yet available information around some relevant subjects. For example, sparse literature on SOEL with HR. This prevented looking into higher DHN temperatures. However, this was likely not that relevant after all. Another example was unreliable predictions on the cost of EHC (electrochemical hydrogen compression).

Due both of the paragraphs above, quite a few estimates had to be done around technological and economical aspects, that could have been more well founded if it was not for these limitations. But they were backed up as well as found possible at the time of writing. And the possible inaccuracies were mostly found to likely not be very crucial regarding the accuracy of the final HR-related results. If the cost of EHC was miss-judged however, the results could possibly be skewed somewhat by this. This also holds for the assumptions regarding heat pricing. However, it is stated that the COP-based pricing is considered a “pessimistic scenario” for HR.

A lot of assumptions also had to be made regarding the setup of the case studies in order to set them up at all. This was seen as acceptable, because the goal was to find the “potential of HR” in future set scenarios. This did not require using exact modelling of existing buildings or DHN infrastructure etc. A more generalized approach was taken. However, if such detailed data were more readily available, this would have opened up for more exact modelling of the DHN part for example. Making things less limited in that sense. That being said, the data that was used was seen as suitable, and not limiting accuracy when taking the goal and scope at hand into account.

All in all, to do this study down to the most fine detail as possible, would have required a large team of engineers and years of time. But time and personnel (in this case just 1) were limited. This thesis is an attempt at a good compromise between resources (e.g., literature, available research, and data), time, and accuracy.

2 Theory

This chapter presents information regarding several areas relevant to the thesis, including:

- Elaborating on thesis background (w. extensive sources) and relevant energy markets
- H_2 components. Electrolysers, compression, storage, and fuel-cells.
- DHNs, batteries, and heat pumps
- Concepts around stored energy for a HESS, from a mathematical point of view.

2.1 Case study energy markets

First, a discussion on energy markets related to the two case studies. This includes the presented pricing years, which are highly relevant for interpreting the results of the coming case-studies.

2.1.1 The energy market and the price volatility of electricity in the UK

Electricity pricing varies due to many factors, and when non-dispatchable renewable sources take over (as discussed in the introduction), the volatility in pricing is expected to increase. In the UK there is as of now an ongoing "energy crisis" which increases the volatility. It started in 2020, and is predicted to last beyond 2030 at least [24].

Beyond 2030 is also when renewable power generation and large scale energy storage should become widespread, according to the nations sustainability targets towards 2030 and zero-carbon goal towards 2050 [25], [26]. Thus, prices might become even more volatile. This space is however seen as quite unpredictable.

The UK has an "expected high future share of non-dispatchable energy generation" and will thus have a large need for energy storage and high price volatility once fossil fuel powered electricity-generation is phased out.

The dispatchable zero-carbon sources in work in the UK today, are nuclear and a very small amount of hydropower. Contributing 15% and 2% of the electricity generation respectively [12]. The potential for increasing hydropower is however low, and nuclear power is quoted as likely to decline in the short to medium term [27].

Once fossil fuels are to be phased out, this leaves a large gap in the power generation demand, that will likely be filled by a combination of solar, wind, and possibly to some degree biofuels (as per section 1.1).

The above constitutes the background for the UK being chosen as the location for the case study about energy storage. It is also the background for running the case study on three different sets of electricity prices. Hourly data for 2019, 2022 and 2023 are used. See Figure 2-1 below.

2022 represents a year of extreme price volatility, even compared to other years in the "energy crisis". 2019, represents low price volatility from before the energy crisis. Noting that information in the preceding paragraphs, may be seen as indication that this will not be representative for actual future scenarios. It is however included for reference. The 2023 electricity prices are somewhat of a middle ground, with higher prices, with similar ratios to 2019 in periods. However, with sporadic dips down towards or even below zero. (See Figure 2-1 below).

How price volatility will look in the future is hard to predict. 2019 and 2022 is in this thesis used as lower and higher extremes. However, whether the volatility will be in between them, or potentially above that of 2022 in the future energy market, is uncertain.

It is largely the ratio between lower and higher pricing is paramount for an energy storage system. Notably, the 2022 set has large seasonal variation. Which one might postulate to be the case in a future where the majority of power comes from wind and solar.

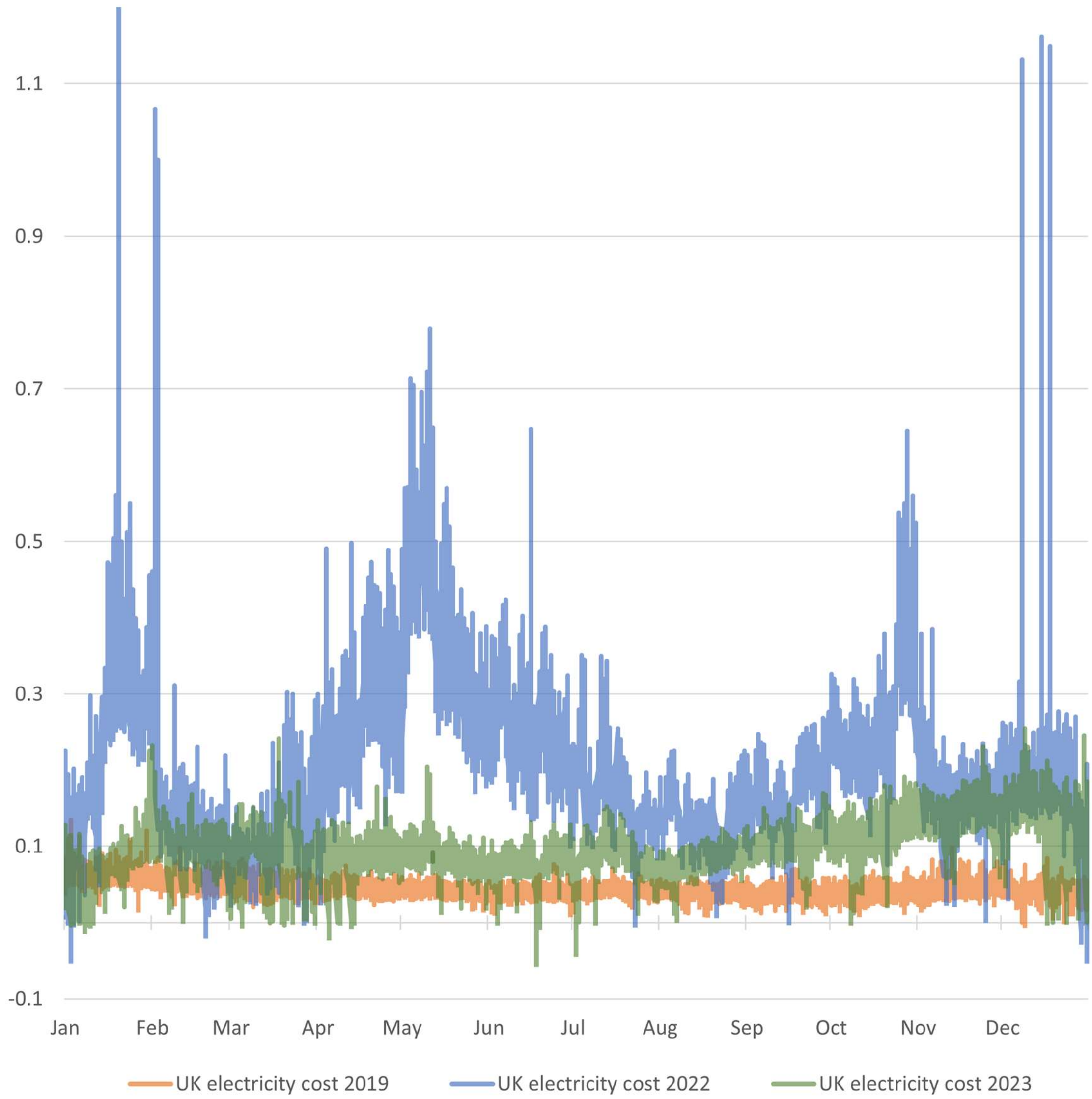


Figure 2-1: Electricity Prices for the UK in 2019, 2022 and 2023 [GBP/kWh] [28], [29]

An assumption done for the first case study, is that natural gas is phased out for heating in the UK, when and where the H_2 energy storage and CHP system is implemented. Acquiring heating energy from gas is not considered. It is in such a scenario that energy storage (including that of the seasonal type) would needed the most as well.

This is done on the basis of assuming that H_2 technology may (at the soonest) become economically feasible (due to economies of scales emerging to a greater degree), towards the time gas boilers are phased out. The phasing out of gas boilers for heating in the UK, is targeted for 2035 (with possible exempts for poorer house-holds, covering about a fifth of homes) [26]. This timeframe also aligns with potential major decreases in H_2 component prices as economies of scale emerge (ref. sections 2.5 - 2.7).

2.1.2 The energy market and price volatility of electricity in Norway

Norway has a RES (Renewable Energy Sources) dominated power grid already today. Yet, it at the same time has a very high degree of dispatchability. This is due to its unusually high share of hydropower, which stands for 88% of its electricity generation [21]. In total, 98% of electricity is from renewable sources, with wind-power standing for the 10% on top of the hydropower and solar being relatively insignificant.

The nation will however have an increase in its energy demand. To meet this demand while keeping a high degree of dispatchability in power generation, one alternative is to decrease the current demand. There's a large potential for this through implementing energy efficient buildings. Lowering the nations very large need for heating which is actually mostly done with electrical power [30]. Another opportunity is for the highly established hydropower sector to upgrade the capabilities and efficiency of some of their most aging facilities. Expanding with new hydropower however isn't easy, as most remaining waterways with high energy potential are protected in the name of nature conservation [31].

To the degree upgrading existing hydropower can't fulfil the increased demand, other renewable sources that will have to fill the gap is mainly wind and solar. Wind power has a large opposition in the local population, also due to nature preservation. Some wind parks are being built, but getting concessions for them isn't straightforward [32].

The nation isn't particularly suited to solar power due to its climate and northern position. However, the nation has a storage capacity in hydropower reservoirs amounting to 70% of its energy. Thus, solar power produced during the nations long summer days can reduce the load on hydropower, which then can be saved for short winter days when solar production will be very low.

Based on the above, Norway's power generation capabilities provides a foundation for stable electricity-prices. However, this has been affected by the country being integrated into EU power markets in recent years (from 2021), and the nation has since seen historically unprecedented price volatility [33]. This is also seen through the country having a somewhat similar trend to the UK for energy pricing in 2019, 2022 and 2023. See Figure 2-2 below.

The development of price volatility in Norway is more uncertain and "policy based" than for the UK. The "power mix" can allow for Norway to retain low pricing variations despite adding more non-dispatchable RES. However, it can also be affected by common power-markets and oversea cables to Europe or he UK.

The former is why it wasn't chosen for the energy storage and CHP case. Because energy storage will not be a necessity to the same degree as it will in the UK. It was however chosen for the H_2 fuel production case, partly because of its low-carbon and historically cheap electricity, together with political forces that presenting a relevant case study opportunity with the express-boats in Trondheim.

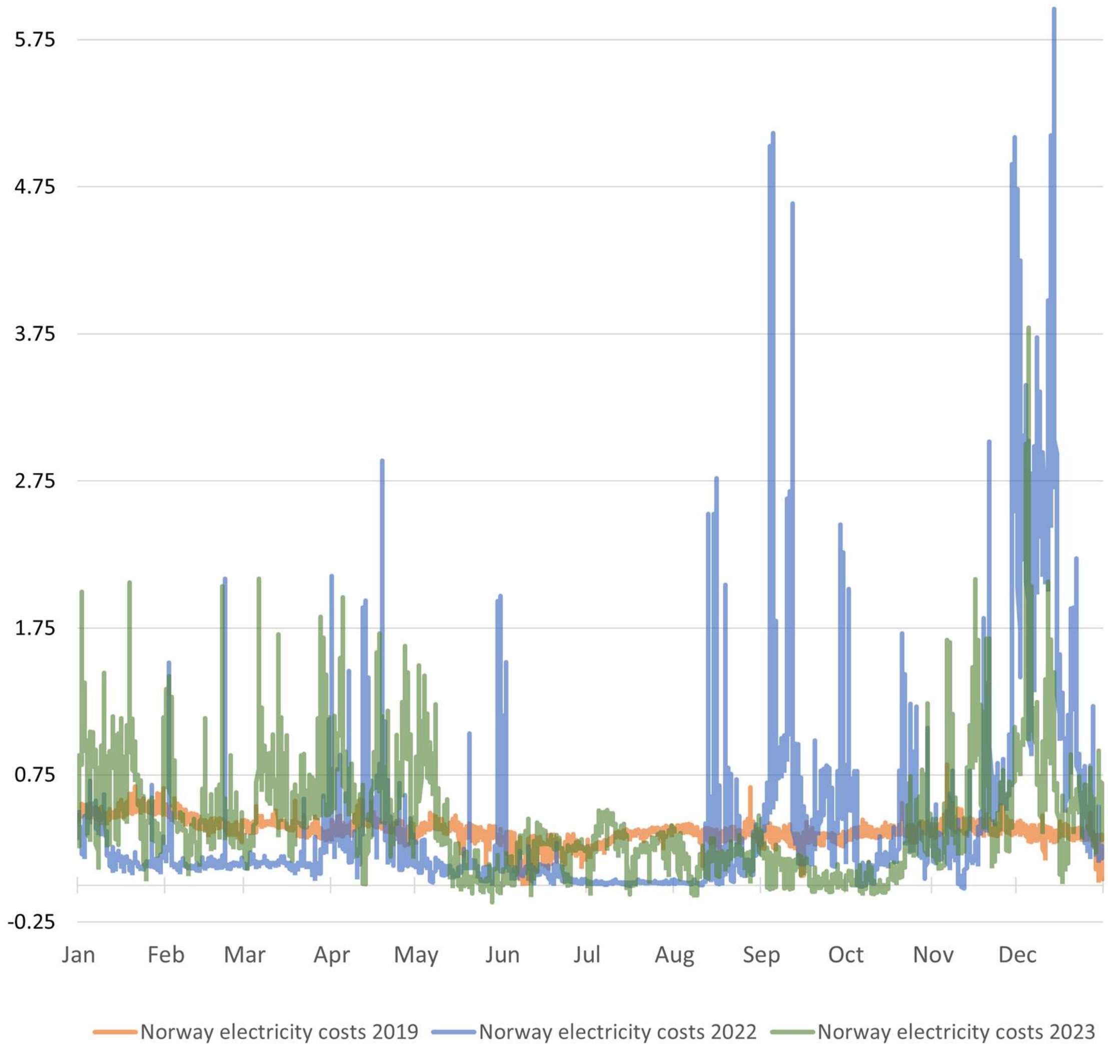


Figure 2-2: Electricity prices for Norway in 2019, 2022 and 2023 [NOK/kWh] [29].

2.2 Battery technology for grid-scale energy storage

While a direct comparison to batteries will not be made, it is still highly relevant to be aware of their characteristics when talking about grid-level energy storage. The following battery-systems will not be presented in the case studies, but their results in the optimization model may be included, for reference.

2.2.1 Lithium-ion batteries

Lithium-ion batteries, or Li-ion batteries, are the leading electrochemical batteries for many applications today. From EVs to energy storage [2], [5].

In the case of energy storage, they are gaining market share due to their high round-trip efficiencies. As well as a large economy of scale emerging due to the EV industry, having caused prices to drop significantly [34].

The preferred li-ion battery chemistry for large scale stationary energy storage, is the lithium-iron-phosphate (LFP) type, due to its low cost per capacity and low degradation [35, p. 6], [36]. This is compared to the NMC (nickel-manganese-cobalt) and NMA (nickel-manganese-aluminium) variants, that are often found in EVs due to their higher energy densities, but these also in stationary storage applications like home batteries [37, p. 8].

Two examples of stationary home batteries are the Tesla Powerwall 2 (PW2) and Tesla Powerwall 3 (PW3). The first of which use an NMC chemistry, and the second of which is unspecified as of now. (Various unreliable sources were ambiguous between LNMC and LFP, and the battery chemistry is not officially specified by Tesla.) At the time of writing, detailed enough specifications for the PW3 are not available, and the PW2 will be presented as an example "home battery" or "distributed storage".

Tesla Powerwall 2

The Powerwall 2 is shown in Figure 2-3, and the Powerwall+ including the auxiliary solar connection components are shown in Figure 2-4 below.

Figure 2-3: Tesla Powerwall 2 - Home Battery (LNMC battery chemistry). Image Credit: Tesla.com [38]

Figure 2-4: Tesla Powerwall +. Image Credit: Tesla.com [39]

Each Powerwall 2 has the following specifications

Energy capacity	13.5 kWh
Maximum power	5 kW

Round-trip efficiency at start of life	0.90
Round-trip efficiency after 10 years[1]	0.70
Default power for charge/discharge power[2]	3.3 kW
UK cost per unit (2023/2024)	Approx. 6 000 GBP
UK cost per unit with installation (2023/2024)	Approx. 10 000 GBP

Table 2-1: Tesla Powerwall 2 Specifications

[1]When it comes to the degradation, the statement by the manufacturer is shown in Figure 2-5 below. Noting, that the 70% figure is the “worst case scenario” against which the ten-year warranty protects. When charging from the grid, the Powerwall 2 is guaranteed to not fall below 70% of its original capacity if the aggregate throughput is less than 37.8 MWh. This corresponds for cycling 78% of the full 13.5 kWh capacity battery daily. This specification is likely related to the fact that NMC batteries is recommended not be charged 100% for regular cycles like this.

[2]As for the charge power, it is stated in the PW2 installation manual, that the 90% start of life round-trip efficiency (RTE) is valid for a 3.3 kW charging rate [8]. Considering that the operational heat for the battery will increase drastically with lower efficiency coupled with a 5kW output, the 3.3 number will be what is used in the model. This is also the only power for which the efficiency is stated.

Ten Year Limited Warranty

Tesla, Inc. warrants that:

(1) Your Powerwall will be free from defects for ten years following its initial installation date; and

(2) Your Powerwall will have an energy capacity of 13.5 kWh on its initial installation date, and will retain energy capacity as shown in the table below.

Application	Energy Retention[1]	Operating Limitation
Solar self-consumption/ backup only[2]	70% at 10 years following initial installation date	**Unlimited cycles**
Any other application or combination of applications	70% at 10 years following initial installation date	37.8 MWh of aggregate throughput[3]

Figure 2-5: Limited Warranty for the Powerwall 2. Image

Thus, the PW2 is assumed to operate with 80% of its 13.5 kWh capacity available for the daily cycling from the grid, and the charge/discharge limit to grid is set to 3.3 kW for its entry into the coming optimization model. The charge/discharge efficiency is assumed to be equal, and thus set to the square root of the round-trip efficiency.

$$\eta_{charge} = \eta_{discharge} = \sqrt{\eta_{RTE}} \quad (2\text{-}1)$$

A more complex operation algorithm could be attempted, by optimizing the battery operation weighing the gains of using higher power/capacity, against predicted degradation effects. However, the operation described above is assumed to be close to the most efficient form of operation in terms of performance per battery degradation for daily cycling from the grid.

Tesla Megapack

Another option for li-ion battery energy storage, is to have it centrally located. Not distributed as is the case with home-batteries like the PW2. An example of this would be the Tesla Megapack. It is a large container-sized battery pack:

Figure 2-6: Tesla Megapack Unit (3900 kWh). Image Credit: Tesla.com [40]

Figure 2-7: Tesla Megapack Grid Li-ion Battery in Western Australia. Image Credit: Tesla.com [41]

Specification	Megapack 2-hour	Megapack 4-hour
Energy capacity	3854 kWh	3878 kWh
Maximum power	1927 kW	970 kW
Round-trip efficiency at start of life	0.92	0.935

Default power for charge/discharge power[2]	Assumed same as maximum power	Assumed same as maximum power
Estimated international cost per unit (1 unit)[1]	2 081 100 USD	1 865 400 USD
Estimated international cost per unit (5 unit) [1]	1 952 000 USD	1 625 800 USD
Estimated international cost per unit (10 units) [1]	1 695 900 USD	1 477 800 USD
Estimated international cost for 2 units (in GBP) without installation[2]	1 915 829 GBP	1 915 829 GBP

Table 2-2: Tesla Megapack Specifications [40]

[1]Costs at the time of writing. Up for potentially large change.

[2]Cost without installation. Installation adding about 36% at the time of writing.

When it comes to the longevity of these systems, it is as explained earlier, highly dependent on the load type, and also the battery chemistry. "Comparison of Li-ion battery chemistries under grid duty cycles" describes capacity retentions for different types of li-ion batteries under different types of loads/grid duty cycles. LFP batteries are clearly most suited in terms of low degradation.

Third party sources mention that the newest version of the megapack moved from an NMC to an LFP battery chemistry, and this aligns with the weight increasing 64% while the capacity increased by less 50% [42], [43]. (LFP cells being less energy dense.) However, no official documents or sources with official references back this up.

If results are mentioned for the Tesla MP or the Powerwall, it will be for "the first year of operation", as taking degradation into account is outside the scope of this thesis. Having this in mind, any quoted MP-results can be interpreted as very optimistic. While the H_2 system also degrades, the decreased efficiency can be somewhat remedied by increased heat recovery output. This which it cannot for li-ion batteries. More so, one should also have in mind that the battery vs. the H_2 system can be very different in terms of their lifespans and rate of degradation depending on many factors.

Despite the above making a direct comparison not feasible within the scope of this thesis, the Megapack is still presented as a reference point, while having the above in mind. The H_2 system in case 1 will actually be dimensioned based on a component CAPEX equal to two megapacks without installation. This way, some comparisons can be made if wished.

2.3 Zero-carbon technologies for energy-intensive transportation

Hydrogen in transportation was introduced in section 1.3. Here, sources will be cited for the claims there. And the potential threat to the validity of the case study that is SSBs. Solid-state batteries. It was found important to establish that they would not render H_2 driven express-boats obsolete, before proceeding with using it as a foundation for the H_2 production case-study.

What is meant by "energy-intensive transportation", is forms of transportation that require using high and sustained levels of power. As mentioned, this becomes a problem for li-ion batteries, mainly due to their low energy density. For which typical values as of 2022, goes up to 0.3 kWh/kg, potentially increasing to 0.35 kWh/kg by 2030 [44, p. 66].

In comparison, petrol and diesel have energy densities of 12.2 kWh/kg and 12.7 kWh/kg, and H_2 has 39.4 kWh/kg. The weight of engines/fuel cell and fuel tanks are however more substantial (and constitutes the majority of the weight) for the latter ones, especially for H_2.

In simple terms, li-ion batteries run either out of charge too quickly, or becomes too heavy, for applications that require very high and sustained power. This is likely why IEA doesn't quote batteries as obtaining market share in aerospace, shipping and heavy freighting (cited in section 1.3). One example of such an energy-intensive application, would be the express-boats operating long-distance daily routes in central Norway. This is where the setup of case study 2 starts.

2.3.1 The case of express boats in Trondheim

The implementation of zero-carbon express boats in Trondheim is politically driven. A local newspaper article states that the six speed-boats in the county "Trøndelag" in central Norway pollute as much as a thousand buses, and has a climate impact per passenger which is over four times that of flying [45]. The CO_2 emission per passenger per kilometre, being as high as 904g, and flying being 198g according to the article. It must however be said that this was a 2019 newspaper article with poor explanation or specificity, and transparency around the figures. And also no citations.

After some additional research, it was found that the report from which those numbers were taken, was a 2014 report by the Norwegian Institute of Transport Economics [46]. In that, the numbers were based on even older data, from one to two decades before that again. Inspecting the report showed that the 904g/passenger-km figure better reflects the generation of express boats used from 2004 to 2014. Boats with aluminium hulls, as opposed to the carbon fibre vessels in operation from 2014 to 2024. In a different article, the same newspaper , as well as an article in "Teknisk Ukeblad" says that the boats introduced in 2014 had 40% lower emissions than their predecessors [47], [48].

Figure 2-8: MS Terningen. Currently (2023) used diesel-powered vessel with a light-weight carbon fibre hull, by "Brødrene Aa". Image credit: "Braa.no" [49].

For the sake of accuracy, using the above together with data for the average emissions per passenger-km for domestic flights in Norway (pre-covid, as it is seen as most representable), we can correct the statement about emissions per passenger km to "2.9 times that of flying" [50]. This is for the boats operating at the time of writing (2023).

De-carbonising this form of transport, would be a major contribution to lowering emissions in a nation that already has a very low footprint in the power generation sector, and is quickly transitioning to EVs for the passenger vehicle market [51], [52]. This is the background for the political initiative to implement low emission or zero-carbon express boats, which was launched in 2019.

Five entries were proposed in 2019 for the next express boat contract period from 2024. (Each period lasting about 10 or more years, based on the length of the previous two contracts). Out of the five entries, three used hydrogen propulsion systems. One was a flying hydrofoil that could use either batteries or H_2, and one was a diesel-electric hybrid which uses a robot-swappable battery pack on the roof of the boat (see Figure 2-10 below).

Figure 2-9: Aero. Hydrogen fast ferry concept by "Brødrene Aa" in 2019. Image Credit: Braa.no [20].

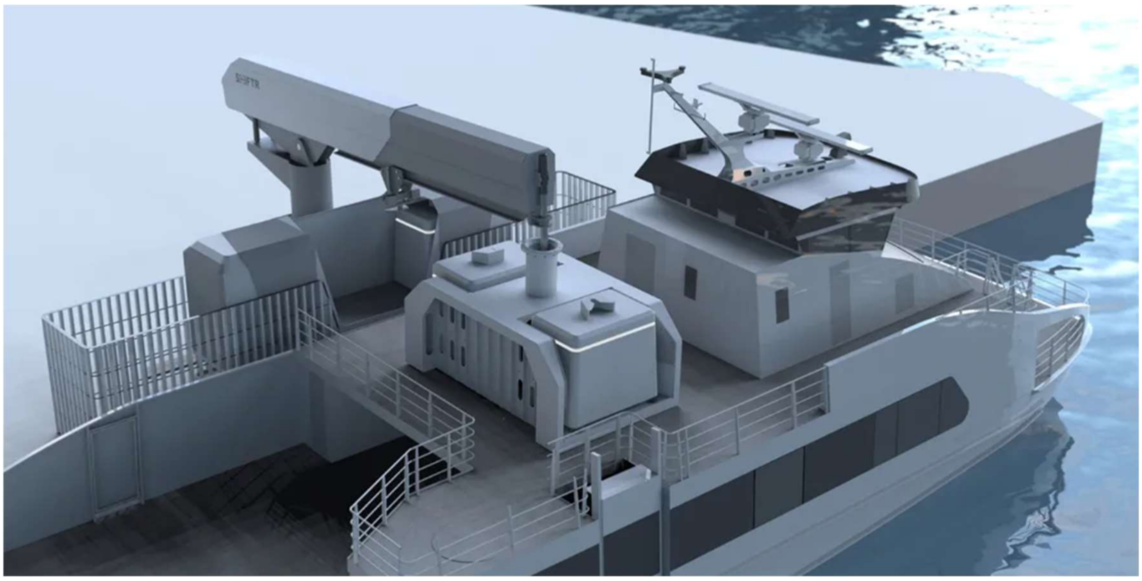


Figure 2-10: Norled Battery-Hybrid Ferry with SHIFTR autonomous battery change robot. Image Credit: Norled [53]

The diesel-hybrid was the one that won the contract, despite it showing that li-ion batteries are not up to the task of de-carbonizing the longest routes. Even if switching out the battery pack with a robot mid-way in the journey, the li-ion hybrid solution is estimated by the manufacturer

(Norled) to have reduced emissions to 30% and 20% of what they were, on the two longest routes respectively [53]. This is a great improvement, but still ends up retaining 85% of the emission footprint per passenger compared to domestic flight in the country. In other words: Still relatively significant emissions.

The fact that the diesel hybrid solution was chosen despite this, when there were three proposed H_2 solutions that would have had zero CO_2 emissions from propulsion, likely speaks to the difficulty or high costs of implementing a hydrogen solution.

However, a study done by SINTEF (a Norwegian industrial and technical research agency) in late 2017, concluded it was logistically, economically, and technologically feasible to use H_2 for the speedboats on the longest route (Trondheim-Kristiansund).

The reasons why a hydrogen-based solution was not chosen, isn't explicitly known. No official statement could be found about it. But major reasons could be the following: The as-of-now very high costs of components and infrastructure associated with H_2 boats and production facilities, safety, as well as the cost of producing H_2 itself.

For these three problems the following can be said:

- The costs of hydrogen components are expected to go down significantly. (See section 2.5 - 2.7, 3.3 for details, sources, and future predictions.)
- Hydrogen safety, is an active field of research, for example being emphasized by the MTP institute (for which this thesis is written for) amongst others at NTNU [54], [55], [56].
- Lastly, the cost of producing Hydrogen, is determined by electricity prices and electrolyser efficiency. As will be discussed (in section 2.5), electrolyser efficiency has a high potential to become very efficient but is commercially relevant systems are in this thesis assumed to retain significant recoverable heat outputs for the foreseeable future.

Recovering this heat by-product may bring the break-even point for H_2 a little closer towards the next express boat contract.

But, before this can be considered, a review of solid-state batteries (SSBs) will be done. As this is a technology that may allow the performance needed to run the Trondheim-Kristiansund route on batteries alone. Thus, it shall be reviewed here how they might make an H_2 solution potentially deprecated, and how this relates to the relevancy of the second case study.

The central questions when it comes to this, is whether SSB technology can potentially achieve the needed performance, and if so, whether it will do so in time for the next express boat contract period.

2.3.2 Solid state batteries vs. H_2 propulsion (for an express boat application)

Solid state batteries (SSBs) that are the "vision" beyond 2035 (as described in the "Solid-State Battery Roadmap 2035+" from 2022). They are not predicted to handle things like shipping and aerospace. But they can potentially fulfil the demands of the Trondheim-Kristiansund route for express-boats (on electric power only) at some point [44]. Making assumptions regarding this is difficult with the available information at the time of writing. Some assumptions and estimations can however be taken.

SSBs are envisioned to have an energy density of 0.5 kWh/kg "beyond 2035", as opposed to li-ion batteries of today which has 0.3 kWh/kg. The SSB thus being able to store 66% more energy.

For the full route, these assumptions can be extrapolated to the SSB-powered boats having 116.7% of the energy needed to make the crossing fully electric. For reference, the fuel capacity for H_2 boats in the SINTEF-study used a 12.5% buffer [57].

The planned route for the 2024 diesel-hybrid solution, switches the battery at “Brekstad”, marked by the northern-most star in Figure 2-11 below.

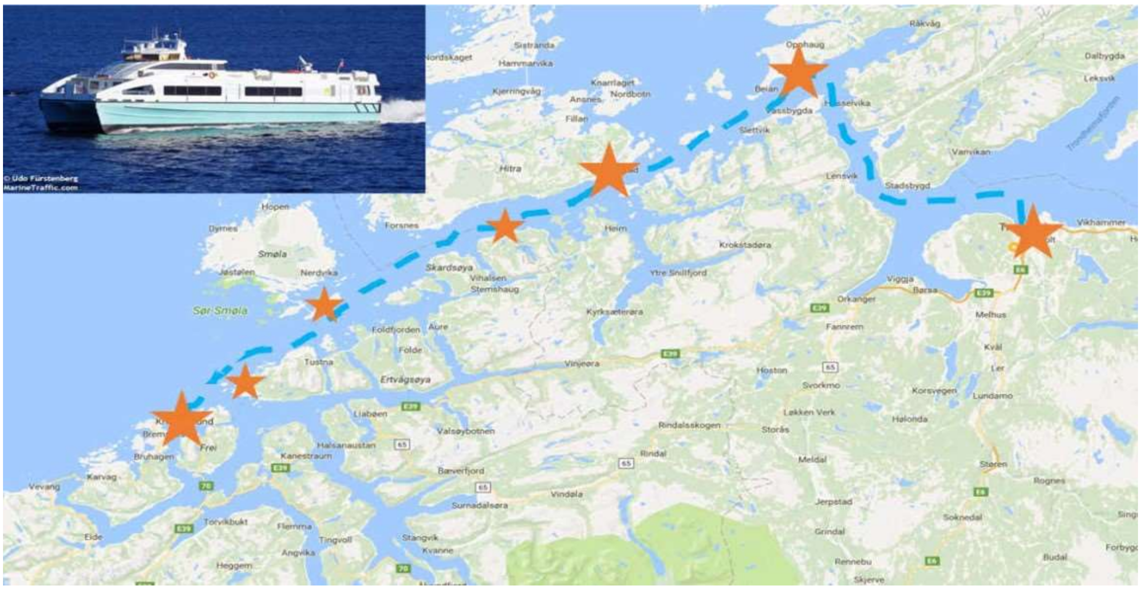


Figure 2-11: The Trondheim - Kristiansund express boat route: Image Credit: SINTEF [57].

The SINTEF study done on the feasibility of hydrogen propulsion for this route, estimated a quarter of the total energy being used for the Trondheim – Brekstad portion of the journey (the rightmost stretch between stars, Trondheim being the most eastern star). The stop at the island of Hitra (one stop southwest of Brekstad) on the other hand is quoted to be exactly mid-way in terms of the energy usage.

Why Brekstad was chosen as the battery switch location was not stated. But the port at Hitra should in theory comfortably be able to support a battery switch and charging facility. This is evident by the fact there are also plans for increasing the port size from 49 to 132 acres in 2025, in order to accommodate a hydrogen production facility [58, p. 10]. A facility meant for other forms of shipping in this area of the Norwegian coast. It is assumed that in the case of SSB-powered boats, the battery switch and charge station would be moved there too, in order to allow for fully electric operation.

At first glance, it then seems like SSB powered boats is the clearcut choice. This is due to the superior efficiency of the propulsion system. The round-trip efficiency of an SSB generally exceeds 90% [59, p. 8]. After all, an important consideration is that high efficiencies cause lower energy costs for operating the route.

Comparing SSB efficiency to that of an H_2 propulsion system, being the product of the significantly lower fuel cell and electrolyser efficiencies, SSB-powered boats seem like a apparent choice. But it is not as straightforward as comparing the propulsion systems efficiencies alone.

As mentioned, the emissions of the boats were cut by 40% when going from aluminium to carbon fibre hull constructions [47]. The cuts were quoted to come mainly from weight savings, as well as somewhat from newer engine technology to “Teknisk Ukeblad”. However, inspection of the official engine specifications for the boats show a similar fuel efficiency, indicating that the light-weight carbon fibre construction accounted for most of the difference [60], [61].

This indicates that a lighter boat, can to a large degree make up for the propulsion system being less efficient. The hydrodynamical efficiency of the craft, is just as important as the propulsion system efficiency. This, together with future developments in electrolyser and fuel cell efficiencies, makes the full picture not necessarily that clear cut.

In addition to increased efficiency for fuel cells, they will likely have a large increase in power density just as for PEM (proton exchange membrane) - based electrolysers (as discussed in detail in section 2.5.2). This will lower both the weight and cost of the H_2 propulsion system compared to what is possible today. This includes a reduction in storage tank weight, due to lower fuel consumption.

Improvements in fuel cell power density and service life, will also help regarding the sustainability of an H_2 boat. Compared to having a fleet of 9 very high capacity SSBs being cycled every day. This should also be a part of the equation if in in depth consideration of the two technologies was to be done. The point of going to zero-carbon propulsion is after all sustainability in the first place.

It should however also be mentioned that a countermeasure for the SSB regarding weight, would be adding more battery switching stations. Whereas this approach would not help the H_2 boat, for which the fuel capacity bears a relatively smaller impact on weight. More battery-changes could also allow for full electrification with batteries, even if a slightly lower value than the “envisioned” 0.5 kWh/kg energy density is reached in time.

In summary, the question of H_2 vs. SSBs is seen as an open question due to the following:

- Overall efficiency might not be as superior to the extent the RTE of the propulsion system alone suggests.
- Due to potential sustainability considerations that have not been taken into account or analysed here.
- Due to high uncertainty regarding the state of H_2 and SSB technology around the next express boat contract period.

In fact, sources are quite ambiguous about the readiness of SSBs around that time. They mention things like “2035 at the earliest”, or “gradual adoption into mass-market after 2035”, and the roadmap for SSBs puts energy densities that would comfortably allow for fully electric operation of the route (0.5kWh/kg) as “the vision beyond 2035” [44]. Meanwhile, the decision to use diesel-hybrids from 2024 indicate that H_2 technology needs to improve. Likely both in efficiency and possibly safety, and probably mainly in costs. Even if it is technically viable to run the route with emission-free propulsion with established technology already now.

Moreso, the time of the next speedboat contract is not set in stone. It will likely be a result of when political forces want a zero-carbon solution. It’s timing in relation to the readiness of each technology is not easily predictable. Thus, the second case study is thus seen as highly interesting, as it will produce a result that may affect the outcome of this question when the time comes.

2.4 District heating networks

2.4.1 DHN introduction

District heating networks (DHNs) are crucial if one wants to utilize the heat by-product from H_2 technology. They work by transporting heat by using water as a medium. A heat exchanger absorbs heat at one location, and then provides it for heating purposes elsewhere, using radiators or heat pumps to transfer the heat to air inside buildings.

The heat often comes from a heat central. Heat sources can include burning household or forestry waste, other bio-energy sources, recovered heat from industry, or other sources. Electric boilers or oil burners may also may also be used as a backup in the case of other available fuels not fulfilling the most demanding load peaks [62].

Figure 2-12 below shows a schematic of district heating.

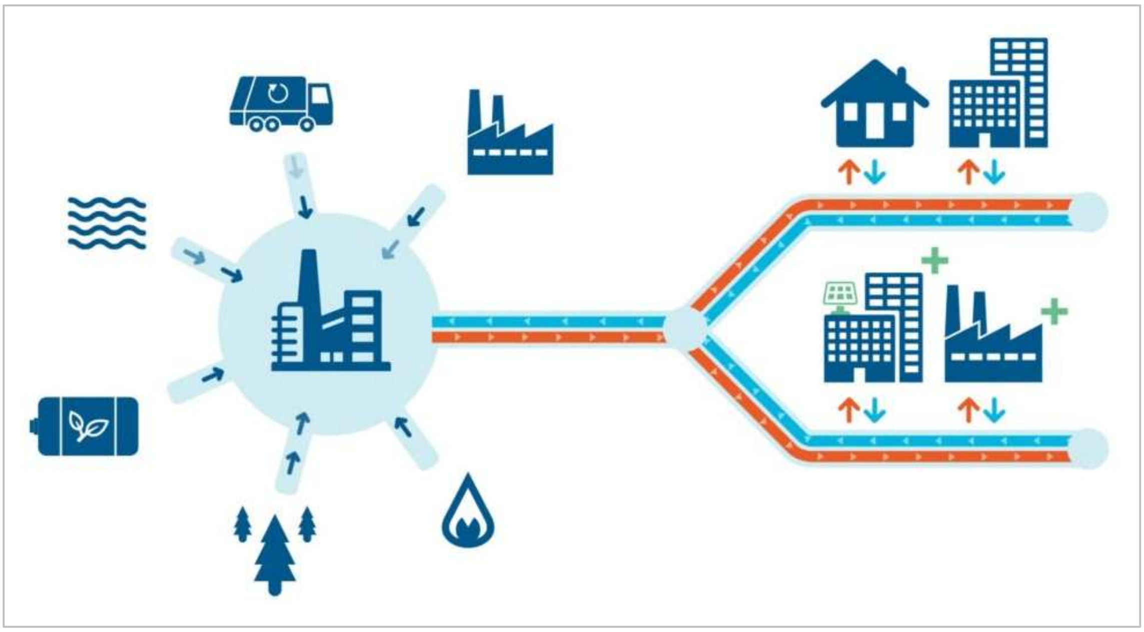


Figure 2-12: Schematic of a district heating network. Image credit: Energiognatur.no [63]

2.4.2 DHN market adoption for case study locations

District heating is also stated to be a central part of reaching London's "zero-carbon by 2050 target" [64], and there are plans for increasing the extent of it considerably by 2030 [64]. Government research indicate that the share of heating done by DHN could increase from 2% in the early 2020s, to as much as 43% by 2050 [10, p. 5]. This was a prerequisite for choosing London as the location for case study 1.

As for the case study in Trondheim (Norway), district heating is widespread, and has a 30% market share of the city's heating needs. The potential city-wide uptake is 666 GWh yearly [65].

Figure 2-13: Boiler room for 3rd gen. DHN in Trondheim (Heimdal facility). Image Credit: Statkraftvarme.no [66].

2.4.3 DHN "generations"

There are several "generations" of district heating, which differ in their types (and quality) of components, and importantly operating temperatures. One notable consideration here, is that the DHN operating temperature must be lower than traditional (3rd gen.) ones in order to utilize some potential low-temperature heat by-products [67].

Different sources state different operating temperatures for different network types, and in general they vary quite a bit between locations as well as between seasons. So instead of giving a simple table, a short paragraph or two will be used to describe each generation here.

Third generation networks (DHN 3.0)

Third generation networks are the current day standard. They are seen as "proficient" DHN systems, and they are the standard way to construct and operate a DHN system today [67]. Typical operating temperatures in summer are given as 65-80°C. Importantly, the systems usually have a minimum return temperature, and a maximum supply temperature.

Third generation networks is the type that is widespread in Norway today. In the location of our case study there, the distribution network pipes are dimensioned for output temperatures up to 100°C, and the transportation are dimensioned for pressurised water up to 115°C [68]. The return temperature there is set to "no higher than" 65°C. The temperature delta for the transportation layer is regulated to be at least 50°C in winter. This is however the transportation network. The parts that take heat into the city districts or building clusters is called the "distribution network" (or, secondary network). This operates at a lower temperature. Technical specifications for the network specified "up to 100°C" as the dimensioning criteria for the distribution network.

Fourth generation networks (DHN 4.0)

Fourth generation networks lower the operating temperatures considerably compared to 3rd gen. Typically 50-60°C. This is in order to increase the usability of low-temperature heat by-products, as well as to decrease losses in transfer. They require "high quality specification, design, construction & commissioning of networks, substations and consumer-side appliances" [67, p. 5].

Fifth generation networks (DHN 5.0)

In DHN 5.0, the operating temperature is taken down considerably again, allowing for more efficient use extraction of recoverable low temperature heat, and much lower transportation losses. This requires using heat pumps to efficiently extract the heat at the site of the consumer.

As well as adding high performance, both in heat extraction, transport, and delivery, this also opens up new possibilities for novel uses of district heating [67]. With adjustment of operating temperatures downwards on warmer days (neutral temperature networks), and running heat pumps in reverse, they can also be used for cooling purposes. With thermal storage, they could even be envisioned to store energy on a warm day, in order to use it again in the night.

It should be noted, that DHN5.0 requires very significant investments, both in water source to air heat pumps on the consumer side, as well as any potential large water source to water heat pumps on the supply-side.

2.4.4 The efficiency of DHNs

The efficiency of DHNs vary with several factors. Such as operating temperature, technical quality of the system components, the physical conditions in which pipes are placed, the outside temperature, and the heat load.

Decreasing operating temperatures have a positive impact on network losses, but also require better radiators to get the heat efficiently transferred to room-temperature air. Density of customers also have a positive impact, due to more heat transfer area being inside and comparatively less outside [69].

The efficiency of DHNs is dynamic, and generally is lower in the summer (when demand is low, causing the distribution net losses to be comparatively high). For example, if one were to run the network when there is very low load, most of the heat would be lost in the transmission pipes as the flow would circumvent the radiators (who's valves would be set to low or zero flow) and the heat would simply go on a round-trip through the distribution network, loosing energy there. Leading to a low efficiency.

In the winter however, operating temperatures would be upped (compared to summer) to deal with the higher load. Higher losses would occur in the transmission due to the greater ΔT for the piping. However, they would be comparatively low when taking into account the now fully opened radiator valves. And to some slight degree due to increased heat transfer from radiators as well, in the case that building temperature drops or due to radiators being placed beneath windows, where air is quite cold for some buildings on a winter's day.

However, modelling this dynamic efficiency will not be done in this thesis. The "handbook of low temperature district heating" says the following about accurate DHN models

> *"Due to the complex nature of DH systems, the development of physical models is a challenging and time-consuming task. Additionally, precise information of the buildings and the DH system infrastructure is not always available or reliable, and due to the detailed definition of the specific systems, the required computational times are significantly higher than for data driven models" [67, p. 120].*

Especially the part about “buildings and DHN system infrastructure is not always available or reliable” is true for the coming case studies, as they are set in envisioned futures. Due to the nature of the case studies this would in case not be obtainable with any degree of reliability.

Data driven models is another (more novel) approach that can be used to model DHN behaviour [67, p. 121]. It is however quoted that “Due to its dependency on existing data, this approach is not suitable for the design of new systems” [67]. Which makes it not applicable in this thesis for the same reason that physical models are not. Both it and the physical model method would involve an amount of guesswork and approximation that could largely cancel out the accuracy of the methods themselves.

A simplified approach will be taken, which is to simply use the average yearly efficiency of the DHN, as a constant across the year. Considering that this is a weighted average with respect to energy throughput, this should be fairly representative of how the efficiency affects the yearly results.

It will for example skew things somewhat between winter and summer though. The effects of this is assumed to be somewhat cancelled out. The lower efficiency in summer in any case affect times of low heat exports, and it can be thought of as being in some part made up for, by deviance in the other direction in winter. Results in this thesis are all given for a full year of operation.

The discrepancy between the real (dynamic) and (constant) average efficiency, will also induce some slight error in the behaviour that the optimization model determines for the system. But the effect of this are also considered likely to not be very decisive. Especially regarding that it is the electricity-components that largely decide the system behaviour. Especially for the case of COP-based heat pricing.

This approach is considered a fairly reasonable approximation. It was conferred with a DHN researcher at NTNU that doing it this way would be “fair enough” regarding the scope of the thesis and scenarios that was worked with.

Efficiency of a low-temperature network in London (Case 1)

The DHN which is to be assumed for the London case (the H_2 energy storage and CHP, or “case 1”) will be a low temperature one. Data wasn’t found on any London network, but more extensive efficiency examples were found on Danish networks. Copenhagen for example has an air- temperature ranging from an average low of 4°C to an average high of 16°C, whereas London has an average low of 7°C and an average high of 19°C. The following DHN-efficiencies were found for distribution networks in Denmark [69, pp. 83–91].

Rural	15%
Suburban	14%
City	5%
New Developments	18%
New developments with LT networks	10%

Table 2-3: Danish DHN Distribution line losses

Here, it can be seen, that City distribution networks have very low losses. However, curiously, new developments have comparatively high losses. This is likely because said developments are well isolated, and thus require less heating. If less heat is put into the buildings, comparatively more will be lost in the transmission-lines. However, LT (low temperature) networks are down back at 10% even for new well-isolated developments.

As mentioned, the efficiency of DHNs vary with many factors. Predicting a very accurate average efficiency for London based on data for Denmark will in any case be a very rough approximation. In general, a slightly warmer climate should make for smaller losses in distribution, but also lower heat demand. But the efficiency is also highly dependent on design/hardware and circumstances around the DHN itself. The envisioned London case will be assumed to have a 10% efficiency, using a low-temperature network.

$$\eta_{DHN.1} = 0.90 \tag{2-2}$$

Efficiency of the distribution network in Trondheim (Case 2)

National statistics for Norway report losses of 10% - 12% in distribution networks [70], [71]. This is largely however traditional DHN3.0 temperatures. Not low-temperature ones.

Conferring with Statkraft (the DHN provider in Trondheim) by e-mail, a 60/40 operating temperature was quoted as the distribution network output and return temperatures used in 2023 onwards. A new low temperature district is also in development in the adjacent borough/district of the one that the case study is set in. So, a low-temperature DHN is the basis.

The district in question will hold mainly new developments at the time of the case study, but also some older buildings. Including the country's largest indoor swimming hall with a yearly heat demand of 6 GWh directly adjacent to the H_2 fuelling station [72].

10% will be assumed as the average DHN efficiency for the connected distribution network in case 2 as well. This is assumed reasonable considering it is an LT network with a mix of building types. If the actual average DHN efficiency will end up above or below this depends on a large range of uncertain factors. In any case, an un-accuracy of +-0.05 for example, should be far from making a difference large enough to invalidate the results to come.

2.4.5 DHN heat pricing

Essential to the value of recovered heat, is the price at which DHN energy is sold. Each house, or each building, may have metering for the heat energy delivered. This was introduced with DHN3.0 [67]. This thesis will proceed as if this metering was "perfect", recognizing that this will not be the actual case.

Two heating policies will be implemented based on the current and proposed new pricing regulations for Norway. All-in-all, there are multitudes of regulations around the world. But considering that Norway is an anomaly when it comes to not using fossil fuels for domestic heating, it is considered as a good example for how DHN-pricing might look in a zero-carbon future elsewhere too. The foundational reasoning for the pricing roof in Norway, is:

"The price of DHN heat must not exceed the price for electric heating" [23].

This thesis continues on the assumption that this will be the natural policy for other countries once zero-carbon heating has to be implemented. However, what "electric heating" means in this context, is up for debate and impending change.

Joule-based heat pricing

The first heat pricing policy will be based on the current interpretation of "electric heating" in the Norwegian regulations as of now. Here, the pricing roof is set by the average cost of obtaining the heat through resistive heating. A traditional form of heating in the country. The current method for this, goes as follows:

- The monthly average electricity spot-price from Nordpool is a basis
- Consumption charge
- Energy-component of grid tariff
- Peak power component of grid tariff.

This constitutes the monthly average electricity price that the DHN pricing roof is set to. And, since DHN providers have natural monopolies, cost of DHN is in effect always set to this roof.

For the electricity-price parts of this thesis, spot-prices are used, which do not include grid-tariffs. Since grid-tariffs are looked away from when importing energy to either of the H_2 systems, it will also be looked away from when calculating what will be "earned back" through the sale of heat.

It may be that energy storage systems and such could be exempted from certain grid tariffs, as they will be vital (and encouraged) for a functional/healthy power-grid. This will not be delved into here. The systems will be judged on energy costs, and the economic effects that grid tariffs may have upon results, is up for being judged "on top" of this.

Joule-based heat pricing for HR, will be the average cost of electricity, times the amount of heat sold that month. This will however be measured as a weighted average depending on the heat output of the system. This is slightly different than for consumers as of now, for which simply the average monthly spot price is taken. Since the H_2 facilities are counted as "energy providers", it makes sense to not let them take advantage of a fixed heat price like this, and rather have the energy price fixed to the current electricity-price.

COP-based heat pricing

However, Joule-based pricing is thought to be outdated today, as electric heating is transitioning to heat pumps instead of resistive heating. On this basis, NVE (the Norwegian Water Resources and Energy Directorate) assigned two firms to evaluate over 70 inputs from relevant players regarding a regulation update. The new regulations will however not be established or published until some point in 2024, after this thesis is finished. The proposal from "Vista analysis" (analysis firm) and "Asplan Viak" (engineering consultancy firm) were as follows. Paraphrasing from Norwegian:

> *… "On the background of this, we propose a pricing roof that is based on the socially beneficial alternative cost, namely heat pumps" [73].*

What this would be compromised of, is a bit more complex than resistive heating. Firstly, one would have to establish a way to calculate the COP with which to divide the electricity prices. COP being the "coefficient of performance", a number that describes how many Joules of heat one gets per Joule of electricity put into a heat pump (see 2.9 for a short review of heat pumps). Measuring the exact COP for every location is not practical, so some compromise would have to be established regarding how to do this.

Secondly, DHN-providers state that basing the price on COP alone is unfair because it does not account for the significant cost of installing a heat pump [73]. A way to do this, could be to add a constant "DHN grid tariff" on top of the energy, which is supposed to equal the long term or average cost of installing and maintaining heat pumps.

Finding the exact solution to this is the job of NVE. However, it is highly interesting and relevant to look at what a COP-based price does to the value of heat recover in this thesis. The exact pricing scheme is however unpredictable at this point. It is chosen to look away from any grid tariff components in this thesis and look at it from an energy perspective only.

This means, that when the thesis presents results for COP-based components, this is considered an absolute "worst case scenario" for the value of heat recovery. One that can be expected to be to some degree worse than actual pricing policies.

A review on heat pumps and COP-data is in section 2.9. Section 2.10 after that, will review the value of stored energy for a system with heat recovery, including mathematical considerations around the detriment a pricing scheme like this will pose on an H_2 system operating as a "buy low, sell high" type energy storage.

How COP-based heat pricing is assumed to be calculated in this thesis

Simply taking the product of the average COP-estimation and average electricity price, multiplying them by the monthly heat demand, will not be fair relative to using heat pumps. It does not take into account the covariance of the factors, especially considering how all of them tend to be high simultaneously. High heat demand coincides with low COP (who's inverse is a factor), and also often higher electricity cost.

The net cost of heat with a heat pumps would be:

$$\sum C_{elec}^{i} L_{heat}^{i} \left(COP^{i}\right)^{-1} \quad \forall i = 1, \dots, n \tag{2-3}$$

Where the i superscript represent the half-hours or hours for which electricity prices are set, C_{elec} is electricity cost and L_{heat} is heat load.

The fair way to calculate the "heat pump equivalent cost" is to take the weighted average as done below, and then multiply that with the heat load.

$$C_{heat.cusomer} = \frac{\sum \left(C_{elec}^{i} L_{heat}^{i} \left(COP^{i}\right)^{-1} \right)}{\sum L_{heat}^{i}} \quad \forall i = 1, \dots, n \tag{2-4}$$

If this is done, then the end heat-cost is equivalent to paying in "real-time" every half-hour or hour. It is the latter that is implemented in the model.

While the heat isn't necessarily actually paid for in real-time in the actual market implementation it should however be as close as possible, to the degree the cost of heat is calculated accurately and fairly. This could be reasonable to implement for "one and one district", where the COP is estimated for the "area" of the DHN for use in cost calculation. From the systems point of view, the fair sale-price of heat would then be calculated as:

$$C_{heat.H_2export} = \frac{\sum \left(C_{elec}^{i} \eta_{DHN} P_{heat}^{i} \left(COP^{i}\right)^{-1} \right)}{\sum P_{heat}^{i}} \quad \forall i = 1, \dots, n \tag{2-5}$$

Where P_{heat} is the heat by-product, and η_{DHN} is the DHN efficiency. How one would actually implement the DHN efficiency in the calculation of the heat price, is however tricky. Metering at several places might be necessary, but this will not be delved into further here. The model treats it as if set to a constant yearly average.

Both case studies treat heat-cost as "real-time", which should fit into a market with a fairly calculated monthly C_{heat} for the district.

This estimation is seen as a reasonable lower estimate for the price of heat. It will in reality likely be higher than this level due to added tariffs.

2.5 Hydrogen Electrolysis

2.5.1 Introduction, and relevant types of electrolysis

In general, electrolysis is a chemical reaction that takes place due to an applied electric current. Hydrogen Electrolysers are devices that use electricity to split water into hydrogen gas (H_2) and oxygen gas (O_2). They have been an established technology since the 1970s.

There are several different types of them. Hydrogen Technologies (2023) quotes the most technologically relevant processes today as [74, p. 207]:

- "Alkaline electrolysis with a liquid basic electrolyte (AEL)"
- "Acidic electrolysis with a solid polymer electrolyte (PEMEL)"
- "High-temperature steam electrolysis with a solid oxide electrolyser cell (SOEL)".

These are the ones that will be considered for the envisioned hardware in the case studies.

Certain operating temperatures are required for each type, to ensure the ionic conductivity of their respective electrolytes [74, p. 208].

Procedure	Temperature (°C)
AEL	70 – 90
PEMEL	50 – 80
SOEL	650 – 850

Table 2-4: Operating temperatures of today's most relevant H_2 electrolysis technologies

Regarding heat recovery, it can be mentioned that all these systems already need heat exchangers for both electrolytes and gas streams. The latter likely being implemented to avoid excessive compression energy. (Ref. temperature T in equation (3-8).)

Figure 2-14 below shows architectures of established electrolysis technologies up until today. The current day PEMEL cell structure has been in use since the 2010s, and the modern Alkaline electrolyser cell has been around since the 1970s. An electrolyser is usually made up of "stacks" that consists of multiple cells, as well as "balance-of-plant" (BOP), which a term for all auxiliary components needed in addition to the cell stack itself.

Typical cell stack efficiencies for AEL and PEMEL is roughly around 78-80% in 2020 and 87% in 2030 according to one paper. This was based on higher heating value (HHV) of H_2. Different sources quote different numbers, and real electrolysers operate at higher pressures. More so, BOP-losses (including water/electrolyte-pumps, cooling system etc.) should be accounted for in the total unit efficiency.

Due to the large variance among sources and various device-sizes etc., a list of typical full system efficiencies will not be given for all electrolysis-types here. In general, their efficiencies are quite similar, although BOP-losses do for example tend to be relatively higher with smaller system sizes [75]. Full system efficiencies will be stated and/or established for the chosen electrolyser units in the case studies.

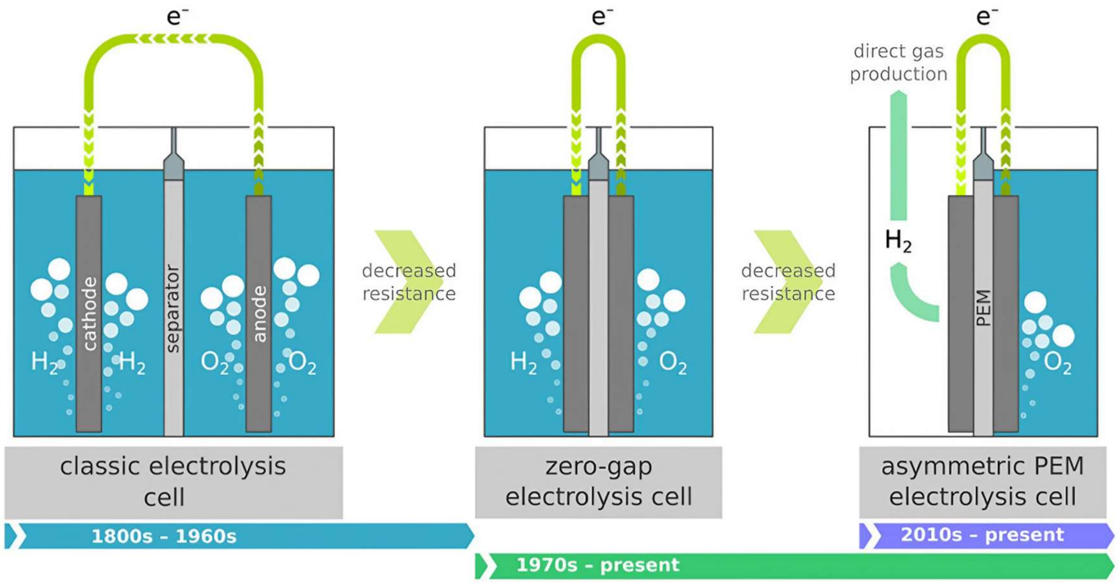


Figure 2-14: Electrolyser architecture. Image Credit: Hodges. et. al. 2022 [76]

2.5.2 Operational characteristics and future developments

Power Density and Efficiency

Besides operating temperature, two important characteristics of electrolysers are their cell voltages, and their current densities.

The cell voltage is related to efficiency. A lower cell voltage means that less energy is required to split the water. Depending on certain parameters, a theoretical minimum voltage is needed to split water. Approaching this voltage is analogous to approaching 100% efficiency. However, ideal cell voltages cannot be achieved during actual operation of an electrolyser [74, p. 210].

Firstly, the voltage is dependent on the relative concentrations of H_2O, O_2 and H_2. Moreso, when a current is applied, ohmic losses, kinetic losses, and losses due to mass transport limitations also occur. Nevertheless, a lower cell voltage remains a good indicator of higher efficiency.

The current density on the other hand relates the H_2 throughput, to the size (or electrochemically active surface area) of the electrolysis cell. Advancements on this front can either lead to higher production rates for the same size cell, or smaller and cheaper cells with the same production rate. Due to considerable material costs, achieving higher current densities will make electrolysis stacks less costly. In other words, the cost per kW of performance goes down, when current density goes up.

The book "Hydrogen Technologies" contained the plot in Figure 2-15 below that show the relationship between the operating cell voltage and current density for different fuel cell types, as well as predictions on their development towards 2030 [74, pp. 212–213].

A basic observation is that the cell voltage rises when the current density rises (as shown in Figure 2-15 below). This innate characteristic leads to the compromise, where one wants to run the electrolyser at a middle ground when it comes to current density. Running it at a high current density (throughput) means your electrolyser CAPEX can be much lower. Whereas running it at a low current density provides a low cell voltage, and thus higher efficiency (lower energy costs).

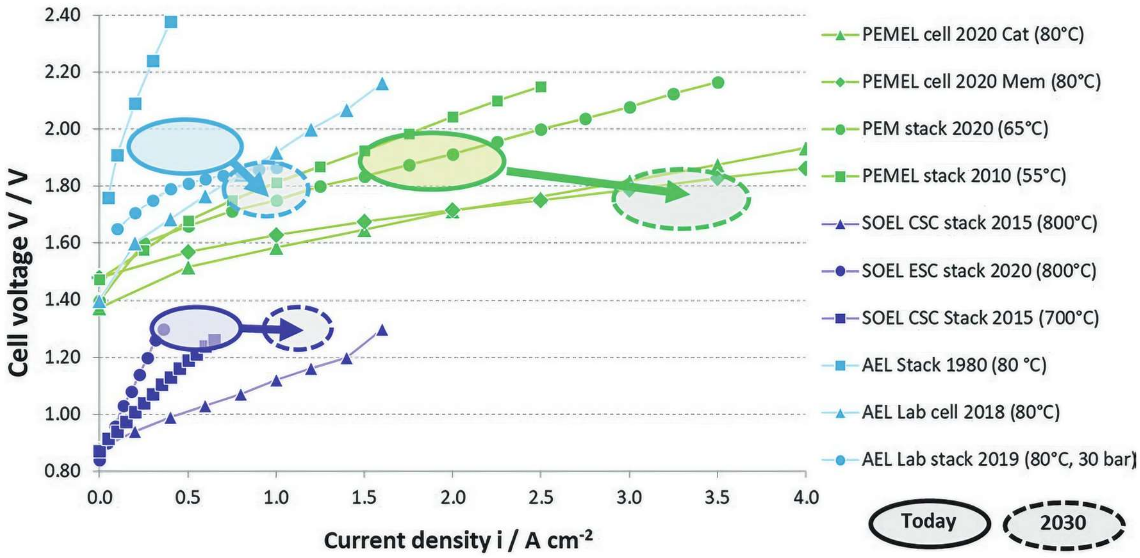


Figure 2-15: Cell voltage and current density projected development. Image Credit: Hydrogen Technologies [74]

Notably, the high-temperature electrolysis types have very low cell voltages. This is due to the operating temperatures of SOEL (also called "high-temperature steam electrolysis"). Here the electrical energy (and voltage) needed is lower, while the thermal energy supplied to the (endothermic) reaction rises with temperature. On top of this the theoretical minimum energy is lower when it is in a gaseous state [74, p. 210].

This is why the cell voltages should not be taken as an indication of performance between technologies. It is only an indication of performance when judged against the theoretical minimum cell voltage for the relevant process parameters. For reference, this is around 1.2V for AEL and PEMEL for example, but much lower for SOEL. Thus, the above figure should mainly be taken as an indication on the cell-voltage to current-density relationship and the expected technological development of each technology.

The cell voltage itself must be also judged together with the thermal input to the reaction. Electrolysis being endo-thermic (absorbing heat). This is around 20% for PEMEL and AEL [74, p. 210]. E.g., the cell voltage distance to the theoretical minimum being halved, would reduce the needed reaction energy by 40%. Halving the 80% that was supplied by electricity in the first place. (See Neugebauer's book for further details and formulas [74, pp. 209–210]. This was included here to allow interpretation of Figure 2-15).

The figure above estimates the typical operating points for the current (2023) and future (2030) state of these technologies. The ellipses moved by arrows represent the magnitude and direction of their cell voltage and current density developments.

Both PEMEL and AEL is projected to roughly have a doubling of their current densities, and a more modest reduction in their cell voltages. From this we can infer that they will go through a modest increase in efficiency (where ca. 1.2V is the baseline for 100% efficiency for these two processes). And, that they will go through a major improvement when it comes to compactness and material costs. SOEL on the other hand, is projected to only improve in current density. Also, roughly a doubling, which should lead to more compact and less costly devices.

Service life forecasts

Figure 2-16 below gives service life forecasts for the different technologies. The source notes, that even if "there are still significant differences in service life, over the coming decades, it is expected that individual cells or complete stacks will not have to be replaced in any of the three processes until over 80,000 hours of operation have passed" [74, p. 212]

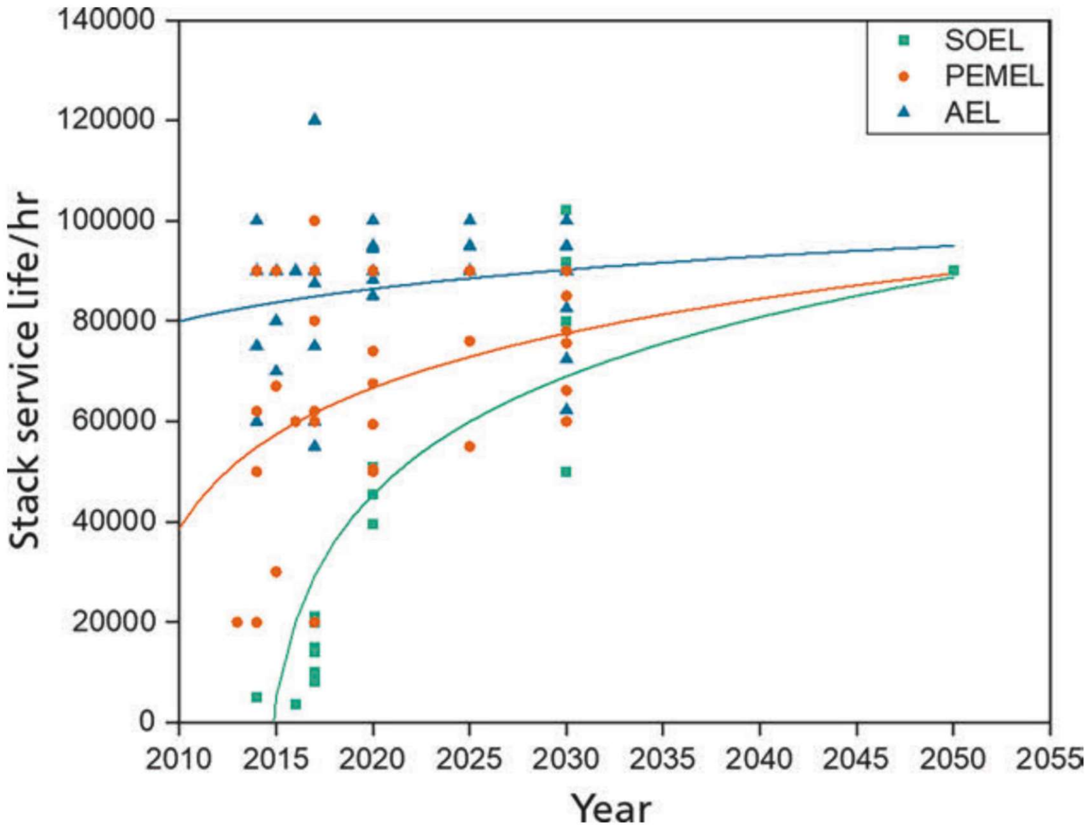


Figure 2-16: Service life forecasts for various electrolysis technologies. Image Credit: Hydrogen Technologies [74]

For reference, the Tesla Powerwall 2 (NMC) Li-ion battery falls out of its guarantee, if it charges more than about 11,500 hours in 10 years. However, the graph above does not mention the cycling patterns of the electrolyser. This will have a major effect on its service life. "Enapter" (an electrolyser manufacturer) recommend their customers to limit electrolyser operative on/off cycles to five per day, and one per hour [77].

The electrolyser will likely be safely within these parameters in the contexts of the coming case-studies. It seems to be so when looking at the results. Although, behavioural rules around things like this, this to account for degradation, is not implemented in the optimization model of this thesis. Neither for batteries, nor the H_2 system.

An in-depth scientific consideration of cycling and degradation is considered outside the scope here but deserved a mention. A potentially higher service life than batteries, is however a potential reason why H_2 is interesting despite its lower performance.

Capillary Action Electrolysers

A recent (2023) development in the design of electrolysis cells, which is not mentioned in the "Hydrogen Technologies" book, is to use capillary action to feed the water to the cathode and anode. This is a recent development at the lab stage, and when we can see devices in the hundred-kW or MW-class is for now not predictable, however their efficiency is revolutionary.

Figure 2-17 below shows the evolution of electrolysis cell structure from the 1970s (omitting the classic electrolysis cell existing from the 1800s) to today (2023).

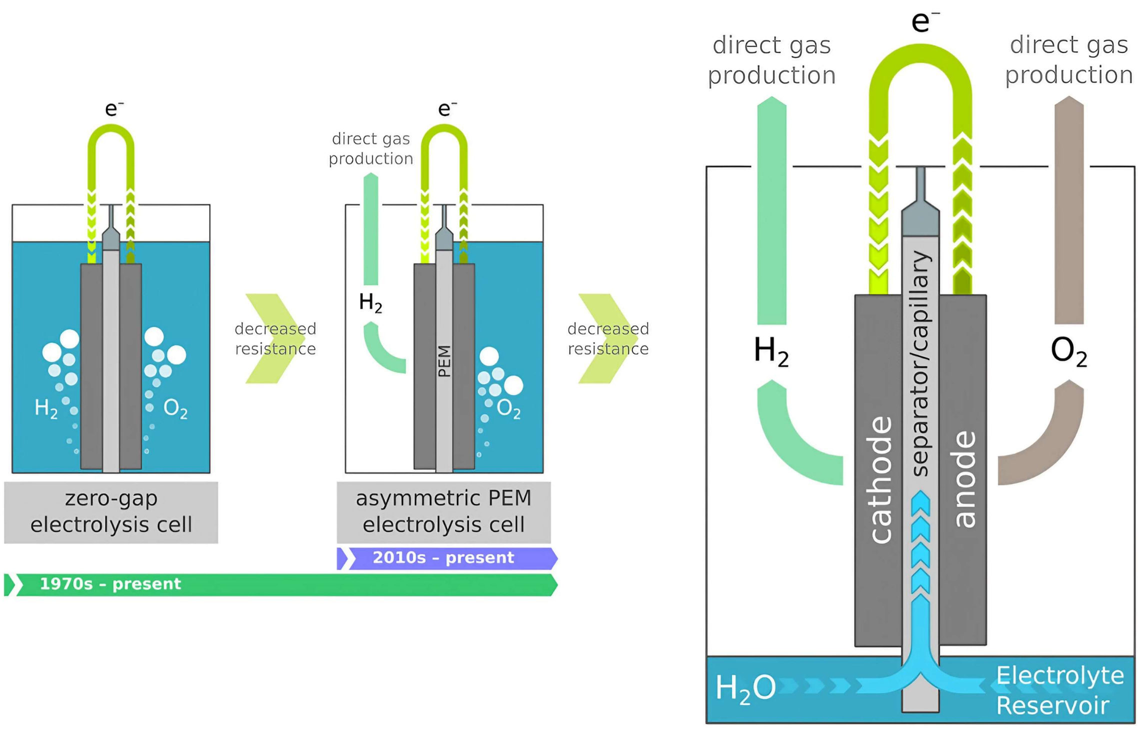


Figure 2-17: Evolution of electrolysis cell architecture. Credit: "A high-performance capillary-fed electrolysis cell promises more cost-competitive renewable hydrogen" by Hodges. et. al. 2022 [76]

Using this capillary action, researchers have shown cell stack efficiencies up to 98% with a 0.5 A/m^2 and 93% 1.0 A/ m^2. This is however for 1 atm. pressures, and for the cell stack only. Not including BOP losses. Figure 2-15 indicates that the latter, 1.0 A/m^2, will be the typical 2030 value for AEL, the technology that said efficiencies were demonstrated for.

Whether there will be a point in heat recovery with this high an efficiency is uncertain. It depends on what efficiencies will be achieved for large-scale (MW-class), mass-manufacturable devices including BOP-losses, and how adaptable their designs can be for efficient heat extraction. Then one has to add in the compression energy and possible HR from that. And furthermore, there is efficiency degradation over the lifetime of the electrolysis cell too.

When it comes to compression energy, it can be noted that compression from 1 atm to a typical pressure of 350 bar would require about 5.5kW (by the rough estimation method described in section 3.4). Considerably more than the 2.3 kW needed from the 30 bars from a typical PEMEL. Although, CAAEL efficiencies for a higher output pressure is not published at the time of writing.

If the calculation/estimation approach later presented in section 4.2.2 is used, the HR of a 98% efficient and 93% efficient CAAEL cell stack including the addition of BOP-losses and compression energy (from 1 atm to 350 bar) is 6.3% and 10% respectively, where 4.7% is HR from the compression device. (For reference, the most optimistic PEMEL system in this thesis has a HR share of 12.8%). So, whereas the value of HR would be diminished, there might still be a point of doing it if one starts at a current density corresponding to 93% efficiency at the units beginning of life.

Furthermore, it depends on whether it can compete with PEMEL in cost in the first place. For 1 – 10 MW units, AEL is predicted to be twice as expensive as PEMEL (looking at relevant AEL values Figure 3-6 in section 3.3). Even with a "discount" based on the purported simpler BOP of CAAEL, the higher capacity per CAPEX might not make it the optimal choice for an energy storage system (for which charging quickly in price valleys can outweigh efficiency). And, as discussed in section 2.10, the fuel cell has the majority of HR contribution in any case, as it is the only HR-component taking advantage of price-ratios in that context. Thus, it is seen as likely that CAAEL will not have a large or disruptive effect on the HR contribution for an energy storage and CHP system, compared to the 2030 PEMEL system presented later in this thesis.

For a fuel production system however, without any grid export taking advantage of pricing-ratios, the value of implementing HR would be much reduced for a CAAEL system. But one still has the consideration that a greater capacities per CAPEX could outweigh the efficiency, through greater capability for leveraging price-volatility. The results of case 2 regarding the performance of system configurations (section 5.4.1) indicate this.

Assuming a CAAEL system would cost 1.5 times more, the optimization model developed for case 2 showed that a PEMEL system with spending that money on increased capacities would perform slightly better than the CAAEL system economically, despite the efficiency discrepancy. No in-depth analysis was done of this, but it was concluded that CAAEL would not necessarily make HR for fuel production obsolete either. It depends on whether it can compete in cost per capacity.

CAAEL and its efficiency prospects was a worthy thing to include in the theory discussion on developments here. But due to all the uncertainties regarding CAAEL at this point it will not be focused on further in the thesis. This is to avoid too much discussion or results based around uncertainties, as well as avoiding clutter regarding the already large combination of "possible scenarios" for which results are to be presented.

2.5.3 Electrolyser market and CAPEX

The costs for electrolyser (and fuel cell) devices are given in currency per capacity (for example USD/kW) by most economic studies on them. This number varies with several factors, such as production volume, production year, and the system capacity itself.

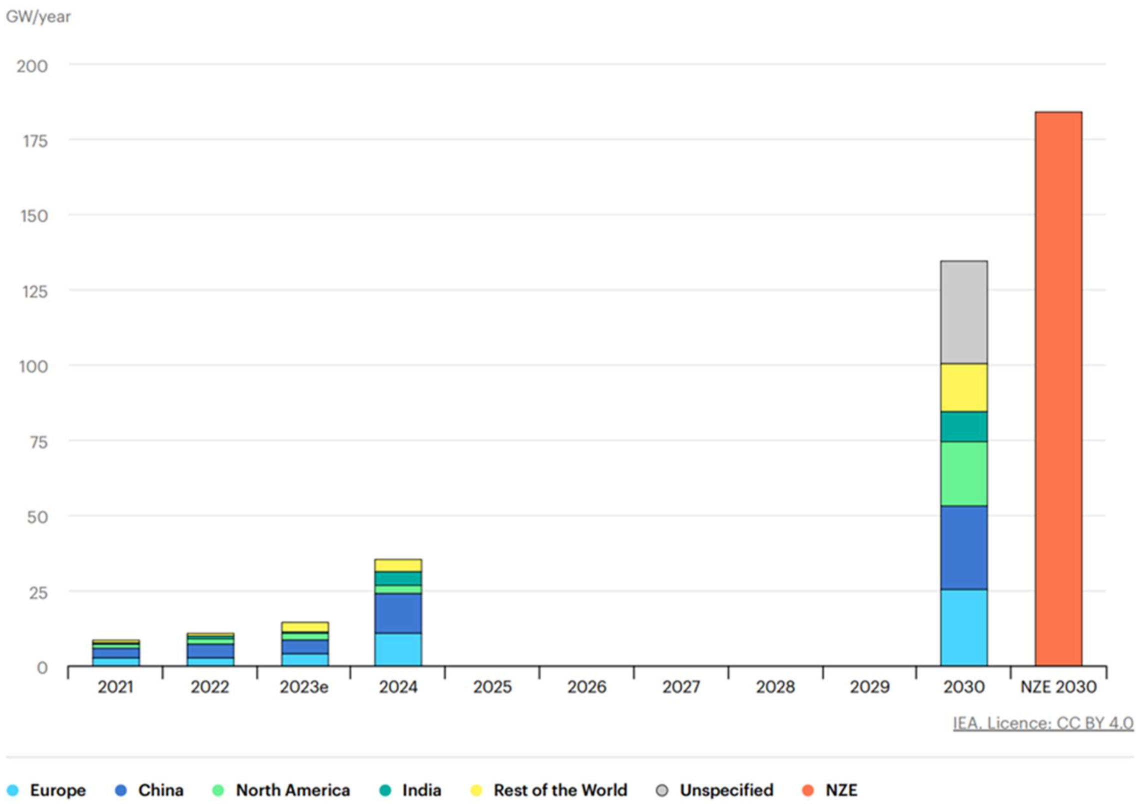


Figure 2-18: Announced electrolyser production capacity. Image Credit: Iea.org [78].

The assumptions for the case studies, is that the production year will be roughly 2030 (or later), and the volume of production is assumed to be increased enough for economies of scale to start lowering costs considerably from those seen today. Figure 2-18 above shows announced manufacturing capacity. Showing that it is purported to increase about an order of magnitude by 2030, while still not quite reaching the NZE 2030 (Net Zero Emission Scenario 2030).

An important and surprisingly significant metric is how the cost per capacity changes as a function of the system size. Reksten et al. proposes a cost trend-line as a function of system size, shown in Figure 2-19 below.

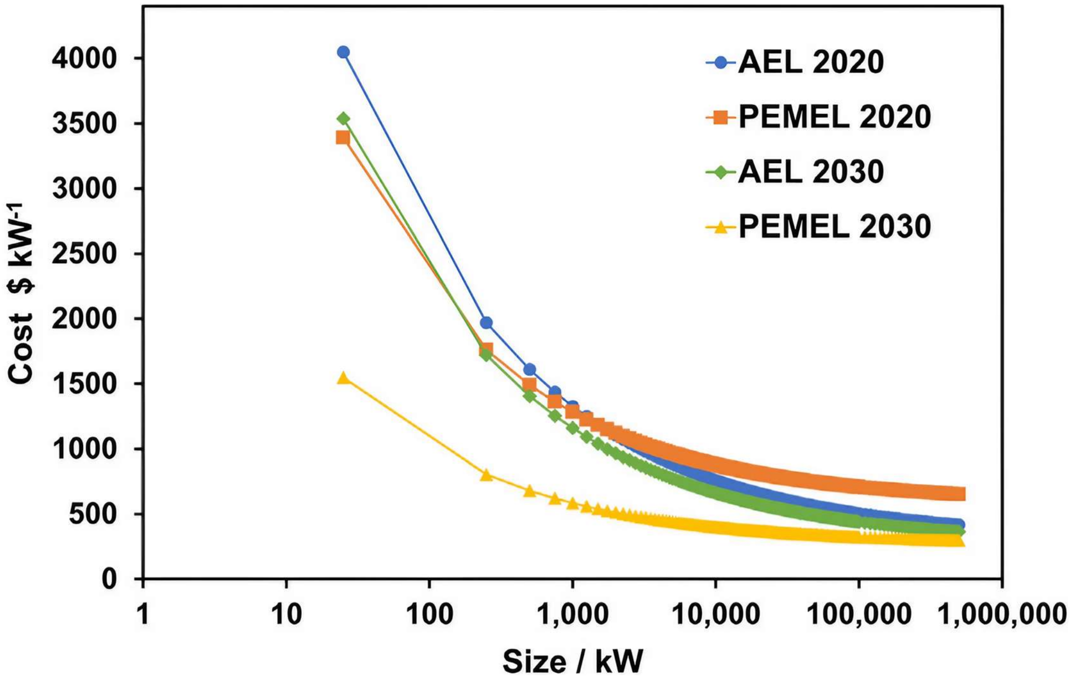


Figure 2-19: Cost per kW, depending on system capacity in kW. Image Credit: Reksten et. al. [79, p. 38110]

A goal for case study 1 (energy storage) is to establish a set of system capacities that are likely. The optimal combination of system capacities for such a system given the total system CAPEX. This is seen as relevant because the configuration of capacities (charge power, storage capacity and discharge power) effects the system operation and the heat recovery contribution that the system will obtain.

In order for it to be possible to establish such a realistic/optimal system configuration, the relative cost of components must be available. Looking at Figure 2-19 it becomes clear that using a fixed cost per capacity from literature would quickly lead to wrong results. Thus, cost functions will be developed for all system components, that approximate a typical cost per capacity for different component sizes. Methodology for this approach this is presented in section 3.3 of the Methods chapter.

Regarding this, it was important to establish for which electrolyser power measure the cost per kW was referring to. This is not very explicitly stated (technically) in the Reksten et al. paper. However, they mention "plant capacity", and several of their sources use H_2 production capacity. One of their sources (from 2003) mentions that out-LHV is the generally used measure for electrolyser capacity. To be certain regarding this critical measure, the authors were contacted by e-mail. They said that the paper referred to "plant input power". The methodology behind how they established plant input power relative to their data sources (many of which gave capacity both in kg H_2 out, out-LHV and stack-power) is not described in detail. But here, the cost function will be used with their parameters, using the system size in input-power as the function input.

2.6 Hydrogen Compression

2.6.1 Compression methods

Hydrogen needs to be stored at high pressures to avoid needing very large space-requirements. There are several methods for compression. A classical one has been mechanical compression. However, due to being large complex devices with high maintenance, and energy efficiency, they are best avoided if possible.

An emerging option is EHCs. Electrochemical hydrogen compressors. These are solid state devices, using a current and a membrane to compress, while also inherently purifying the hydrogen. Due to numerous advantages, it will be the component of choice if further compression beyond the electrolysis pressure is to be implemented.

EHC, uses a PEM (proton exchange membrane), just as PEM fuel cells and electrolysers. They have a superior efficiency, single stage compression ratios and size, and they also operate silently. Mechanical compression on the other hand, generates significant noise, and is also much more expensive and difficult when it comes to maintenance [80, pp. 71–72].

EHC devices also follow an isothermal compression process, which innately requires less energy than the adiabatic compression process of a mechanical compressor. Another advantage of EHC is that it also innately purifies the H_2 as hydrogen is transported through the membranes [80, p. 72]. From here on, the EHC will be the discussed form of compression.

An option for compression, however, is to store the hydrogen right from the electrolyser (for example at 50bar to 80 bar). However, storing it in a gaseous state is traditionally done between 350 to 700 bar in order to reduce tank size/space-requirements. Using an EHC also helps with purity, which is important to LT-PEMFC (low temperature PEM fuel cells) for example.

Section 3.4 in the Methods chapter will explain in detail the method that was used to find/estimate the compression energies for different situations in this thesis. In short, an energy needed per kg of H_2 compressed from a certain pressure to another will be added to the total H_2 production input.

Heat recovery from the EHC will also be implemented. The foundation for EHC compression is that it is isothermal. However, the inefficiency of the EHC will produce heat upon the energy that goes to isothermal compression. One source stated that 60% or above is usual for EHCs. However, the data given by HyET (an EHC manufacturer) contradicts this. Using their graphs (Figure 3-10) as a basis and solving for η_{EHC} by equation (3-9), roughly 50% efficiency or considerably lower can be found for the efficiency number. This figure changes drastically with current density, and with the pressure ratios. Especially compressing from low electrolyser output pressures (e.g., atmospheric) increases compression energy by a large amount.

2.6.2 Cost of EHC

When it comes to the cost of EHC, sources are sparse. A paper on recent progress and challenges by Marcius et. al. states that: "the capital investment for EHC varies from 143.72 €/kgH_2/day to 1437.18 €/kgH_2/day compared to the 1944.42 €/kgH_2/ day of a mechanical compressor" [81, p. 24180].

The unit that will be used for this in this paper, is the cost per kW equivalent (HHV) of electrolyser output. While kg H_2 is a tidier unit to reference, the kW figure is relevant here. Finding the energy flow of the full system being a final goal. To establish this, the following calculation was done.

$$C_{EHC} = \frac{C_{kg.day}}{24h/day} E_{HHV.kg} \quad [\$/kW] \tag{2-6}$$

Where $C_{kg.day}$ is the cost per kg per day, and $E_{HHV.kg}$ is the energy amount in 1 kg of H_2 (HHV). C_{EHC} is the cost per kW equivalent (HHV) of throughput. This needs to be equal to or greater than the electrolyser production capacity. For this thesis, the EHC capacity will always be set to equal the electrolyser HHV output capacity (in kW).

In GBP/kW of H_2 throughput equivalent), the lower and upper EHC numbers quoted above, becomes 88 and 880 respectively. In other words, the cost of EHC per throughput, has cost figures within a whole order of magnitude. Including it in a cost function, thus brings with it a high degree of uncertainty.

HyET (an EHC manufacturer) states the cost to be 300 USD/kg/day [82]. This corresponds to 170 GBP/(kW of HHV H_2), as per eq. (2-6). In the lack of more pieces of data and nuanced descriptions of EHC cost, HyET's number will be used in this thesis. It must however be stated that this is a rough assumption. It might be an optimistic one regarding the 2030+ scenario. For it, the EHC is also assumed to run at a low current density (meaning relatively higher CAPEX per capacity), whereas the conservative scenario has it running at a medium current density.

Then there is the question, if this cost should be assumed to for example have a power law trend, like the electrolyser. Or to be assumed more linear. It might be the case that EHC units will be more modular (as per HyETs current ones) and mass produced in smaller units. Or they could in the future be large units that will have their price per capacity go down with higher capacities. Data for this or any manufacturing economics analysis, is as of now yet available. An assumption has to be made.

It is assumed that they will take on a similar relationship as PEMEL in the future when larger devices likely will enter the market. In lack of available data/sources on this front, the EHC cost will be added as a factor onto the electrolyser cost.

Establishing EHC cost estimation function

The 170 GBP/(kW of H_2 throughput equivalent) found above, was derived from numbers that HyET based on a production rate of 300kg/day [82]. This equates to an electrolyser HHV output of 493 kW. Such an electrolyser unit would by the established electrolyser cost function for this case, have a cost per capacity of 537 GBP/(kW H_2 equivalent). The factor one would have to use on the electrolysis cost to include the EHC is 1.32. This is a very rough approximation, but it's seen as a reasonable one in lack of any data. However, since the required EHC capacity is that of the electrolyser output, not the input, the 0.32 component of this factor should be multiplied by η_{ELY}. The total cost of electrolyser plus EHC is approximated as:

$$C_{ELY}(1 + 0.32\eta_{ELY}) \tag{2-7}$$

Where η_{ELY} is the electrochemical efficiency (HHV) of the electrolyser.

This is however a simplification that may bring with it notable inaccuracy. An attempt was made to get as good an approximation as possible at the time of writing, whilst an in-depth analysis of EHC cost data or manufacturing economics was found not feasible at this point. A disclaimer is made, that this is a rough approximation, and in the case of better sources being available this estimation is subject for revision. However, as will be discussed later, in-accuracies in the cost functions are not predicted to have very large impacts on the thesis results about the value of HR. Unless they miss by a large margin. And basing things on a cost estimation will undoubtedly make the results more accurate and relevant than finding results for some arbitrary set of system capacities.

2.7 Hydrogen Fuel Cells

The book "Hydrogen technologies" by R. Neugebauer describes fuel cells as follows:

> *"Fuel cells are energy converters that transform the chemical energy of a fuel into electrical and thermal energy. As such, they enable cogeneration of heat and power" [74, p. 253].*

2.7.1 Fuel Cell Technologies

There are many different fuel cell technologies. The following table is taken from the R. Neugebauer book [74]:

Technology	Advantages	Disadvantages	TRL
LT-PEMFC	- High power density - Long service life - Good start-stop and cycle stability	- Low tolerance of contaminants - Complex water management system	9
DMFC	- Good start-stop and cycle stability - High energy density (methanol)	- Low efficiency - Low power density	9
SOFC	- High efficiency - High tolerance of contaminants - Long service life	- Medium power density - Low start-stop, and cycle stability - Long startup time	8
HT-PEMFC	High tolerance of contaminants Moderate startup time	- Medium start-stop and cycle stability - Medium power density	8
MCFC	- Wide range of capacity - CO2 management - High efficiency when used with CO2-based fuels - H_2 as a by-product	- Low power density - Low start-stop and cycle stability - Long startup time	8
AEMFC	- Precious-metal-free catalysts	- Low power density - Short service life to date	3

Table 2-5: Overview over various fuel cell technologies. Taken from "Hydrogen Technologies" [74, p. 255].

Here we may recognize the PEM, SO and AE beginnings of abbreviations, being the same as for the electrolysis technologies. These are also those out of the above that are relevant for use with Hydrogen (the book also talking about fuel cells using other fuels. A notable difference, is however that AEMFC in this case has a low technology readiness level (TRL), compared to AEL which has the highest technological maturity amongst electrolysers.

Since a low temperature PEM unit is chosen for the electrolyser already in this thesis, it is right away clear that this also will be the case for the fuel cell as well. Besides the fact that the other hydrogen options have long start-up times or low cycle stability, and AEMFC has a low TRL.

The above table also include the reasons that LT-PEMFC predictions are used for modifying the fuel amount calculations for the express boats in case study 2. PEMFC is one the fuel cell types suited to marine applications (together with SOFC) [83]. However, it is the only one that is quoted to have high power density, which is vital for applications in express boats where weight is paramount to overall craft efficiency.

2.7.2 Notable differences between fuel cells and electrolysers

Besides the obvious difference, that they work in opposite directions (fuel cells turning H_2 back into usable forms of energy), there are some major differences to take note of.

The first, is that fuel cells are significantly less efficient than electrolysers, both currently and when it comes to "future predicted potential". Secondly, they are significantly more expensive per capacity as well.

Whereas electrolyser efficiencies range from around 67% to 77% (full system incl. BOP), fuel cell efficiencies found in this thesis ranges from 47% to 58%. *This being for the units used in the coming case studies. (See section 4.2 for calculations and cited sources.)

When it comes to price, the cost estimation function for fuel cells (presented in 3.3) indicate them being about 2.5 times as expensive as electrolysers. This however is for the systems NET electrical output power in LHV, which is a very different measure than the system input power which was used for the electrolyser cost. The optimization model will however use the net input power: The kW equivalent of H_2 HHV as its measure of fuel cell power. To better keep track of energy flow.

This gives the following relationship between the fuel cell capacity of the model, and that of the cost function:

$$\eta_{FC.HHV} z = z_{output} \tag{2-8}$$

Where z is the models fuel cell capacity, the HHV input to the fuel cell. And z_{output} is the cost functions capacity, the electrical output power. And $\eta_{FC.HHV}$ is the HHV efficiency of the fuel cell. The cost function, is then:

$$K_{FC} = C_{FC} z_{output} \tag{2-9}$$

Where C_{FC} is cost function for cost per output capacity z_{output}. K_{FC} is the fuel cell CAPEX.

Notably, LHV efficiency is the standard measure by most literature and manufacturers. However, the HHV- efficiency is used in this paper, because HHV was the sensible measure to use when dealing with heat recovery for the electrolyser. The same measure of H_2 energy content must be used on each end, in order to rightly keep track of the H_2 used and produced.

HHV vs. LHV is an area of "major confusion" when talking about H_2 systems. To get HHV efficiency from LHV efficiency, a factor of (33.33 kWh/kg) / (39.39 kWh/kg) = 0.846 is applied. HHV efficiency is the energy output per HHV energy content (39.39 kWh/kg) of the fuel. LHV efficiency is the energy output per LHV (33.33 kWh/kg) energy content.

2.8 Hydrogen Storage

2.8.1 The energy content of hydrogen

As just mentioned, for hydrogen storage (like with other chemical fuels) one has two different energy content values. This has been quoted as “a topic that has given rise to much confusion in the literature” [84, p. 281]. HHV is used consistently throughout this thesis for mentioned reasons, including for the storage energy storage amounts. But be aware that these values are 18% higher than if the energy contents were given by LHV, which it might be elsewhere.

2.8.2 Hydrogen Storage Technologies

Hydrogen can be stored either at high pressure, or in liquid form at lower pressure but extremely low temperatures. For the stationary application we’re looking at, it can be noted that weight is not an issue outside of installation. Further, how relaxed the space or compactness requirements will be, is uncertain. The most important characteristics for the coming case studies, is however: Energy efficiency, cost of acquisition, and cycle-life/lifespan.

The volumetric energy density of H_2 is very low at atmospheric pressure (equating to just 3.3 kWh per cubic metre). This is why it normally compacted as much as feasible [85]. In vehicles 350-700 bars is common, but going for electrolysis-based pressure levels could possibly be acceptable for stationary applications on the expense of larger space requirement. This also improves efficiency slightly by avoiding losses associated with compression. However, as seen later in section 3.4, the energy requirement for compression if using an EHC can be said to be relatively low.

Liquid Hydrogen Storage

Liquid storage achieves superior energy density compared to storage of gaseous H_2, without very high pressures. But constant energy use is required for cooling, and boil-of rates are relatively high compared to compressed gas leakage. According to the US Department of Energy (US DOE), “Using today's technology, liquefaction consumes more than 30% of the energy content of the hydrogen and is expensive” [86]. In a storage and CHP system, much of the energy used for cooling the hydrogen could potentially be recovered through heat capture. However, this would lead to an overly large portion of the system energy being heat. NASA has performed research and demonstration of zero boil-off liquid Hydrogen [87]. However, energy-requirements for the refrigeration will naturally remain high even if boil-off rates can be achieved, considering the hydrogen’s phase transition temperature is -253°C [88].

While the overall efficiency of a system with heat recovery may easily match or even exceed that of other technologies through heat recovery, this is a misleading indication of performance in an economical energy storage context if one takes into account the lower cost that could be had for heat by using a heat pump. Too large losses to heat should thus be avoided when possible. Liquid storage will thus not be considered further in this thesis.

Figure 2-20: Five H_2 Tanks by Iberdrola. 237 MWh (HHV) capacity for each tank. Image Credit: Idesa.net [89]

Pressurized Hydrogen Storage

On the contrary to liquid storage, losses are very low in all types of pressure tanks. So low, that they can be considered insignificant. The maximum leak rate allowed by regulations is 1scc/hr/l [90]. For 350 bar this equates to 0.012% of each kg of stored hydrogen leaking out each hour, or 0.3% per day. For reference, this maximum allowable rate would amount to about "one full storage capacity" of H_2 leaking over a year. But this is for the maximum allowable rate during testing, and manufacturers are likely to stay well inside the safe side of this. If one assumes this, it should make for energy loss rates roughly around the same order of magnitude as li-ion batteries (<5% per month) or possibly quite a bit lower [91]. For the purpose of this project, leakage rates are considered negligible. They are not considered further, and loss of charge is not modelled for either technology.

There are four categories of pressure vessels. Types 1 to 4 (or often referred to as type I to IV). Listed, in Table 2-6 below.

Category	Construction
Type I	All-metal
Type II	Metal linear with composite cylinder
Type III	Metal liner with full composite overwrap
Type IV	Plastic liner with full composite overwrap

Table 2-6: Pressure vessel classifications

Type 1 Pressure Tanks

Type 1 pressure tanks are commonly found for H_2 in industrial applications today. They are made of metal only, and are the lowest cost and heaviest gas cylinder type [92].

An issue they face, is the Hydrogen embrittlement of steels. A common cause of failure for pressure vessels, is cracking by fatigue damage (cyclic loading). Steels (and metals in general) are much more susceptible to fatigue damage when they are brittle [93]. The stress required for cracks to initiate and propagate becomes lower when Hydrogen permeate the metal. Several techniques have been proposed to combat this effect. This includes selecting appropriate materials, dimensioning the tanks for a corrosive environment (thicker tank walls), thermo-mechanical treatment of steels, as well as using coatings or protective layers on the insides of the tanks [94].

The service life of standard type 1 tanks depend greatly on their design and there is no general "guideline". Their operating pressures usually in the range around 200 bars [95]. An advantage they have against the composite-based tanks, are that they are cheaper and easier to manufacture in large sizes, such as our application will require.

Two example MEHGC (Multiple Element Hydrogen Gas Containers) were found. However, figures were removed due to copyrighted webpages. See references if visuals are of interest [96], [97]. There were however both 20 ft containers (standard shipping-container size). One contained 6.9 MWh of (HHV) energy stored at 180 bar, and the other 11.8 MWh at 300 bar. This gives an idea of the storage capacity relative to storage size. For reference, a Tesla Megapack holds about 4 MWh and is of roughly the same size (keeping in mind that entire battery vs. storage tanks is far from a direct comparison).

Type 2 Pressure Tanks

Type 2 tanks use composite materials wrapped around the cylindrical section of the pressure vessel, to deal with the tangential stresses for which requirements are roughly double than the axial ones dealt with by the spherical tank ends [98, p. 786].

Type 3 and 4 Pressure Tanks

Are tanks with full carbon fibre constructions. In the case of type 3 with a metal inner liner, and for type 4, a plastic liner. The liner being the inner gas-impermeable barrier, which isn't necessarily load-bearing (responsible for resisting pressure).

These can generally operate at a higher pressure, or alternatively at a lower pressure with a higher cycle life, compared to type I containers [99]. MAHYTECH stating that their 60 bar lightweight containers can hold for 27 years worths of daily cycles, with a 20-year rated service life of the tanks. Their 350-bar tank were however rated for half that.

Composite tanks are considerably lighter, and thus on the forefront when it comes to research in this area regarding hydrogen as a fuel in vehicles. Developments motivated by this sector, that has effects on cost, will also make them more applicable for stationary storage. The cost of carbon fibre is the main reason why they are more expensive than type I tanks. The costs of carbon fibre was reported as 70% of costs for large scale production of 700 bar tanks by one source, and 80% for both 350 and 700 bar tanks by another [100, p. 7], [101, p. 3043]. One source can be quoted as saying: "It is expected that with additional cost reductions in carbon fibre and improved manufacturing methods these technologies (composite tanks) could ultimately cost less than the traditional metal Type I cylinders" [92].

Further notes about type IV tank specifications, is that in the case of automotive applications their empty pressure are quoted as 20 bars (2.5 – 5 % of storage capacity) and their cycle lives are given as 5500 cycles. However, these are off course performance indications, not general specifications.

Example MEGC (multiple element gas container) units (by NPROXX) was found, which had HHV storage capacities of about 20 MWh for a 20ft container or 40 MWh for a 40ft container (both at 500 bar). The former then holds about the HHV energy content of about 5 similarly sized Tesla

Megapacks, or roughly 2-3 Tesla Megapacks of useful energy (going from HHV to LHV, and accounting for a 2030 fuel cell efficiency).

2.8.3 A note on the cost estimation function for storage tanks

The cost function for the storage will be stated in the case study chapters, depending on what tank types are chosen. But notably it was decided to assume a linear relationship here, not a power trend-line as done for all the other components. This is thought of as reasonable considering the high material costs, coupled with the fact the storage will likely consist of very small pressure vessels, predicted to be mass produced in very large numbers. Example MEHG container units were seen to consist of anywhere from roughly 50 to 100 small tanks for a 20ft container [96], [97], [102], [103]. And the H_2 systems in the coming case studies will use several such units. Thus, the cost will be set to a linear function of the storage capacity. I.e. the cost function is simply a constant.

2.9 Heat Pumps

2.9.1 Heat pump introduction/fundamentals

A heat pump is a device that "transfers heat from a low-temperature medium to a high temperature one" [104, p. 285]. As illustrated by the figure below:

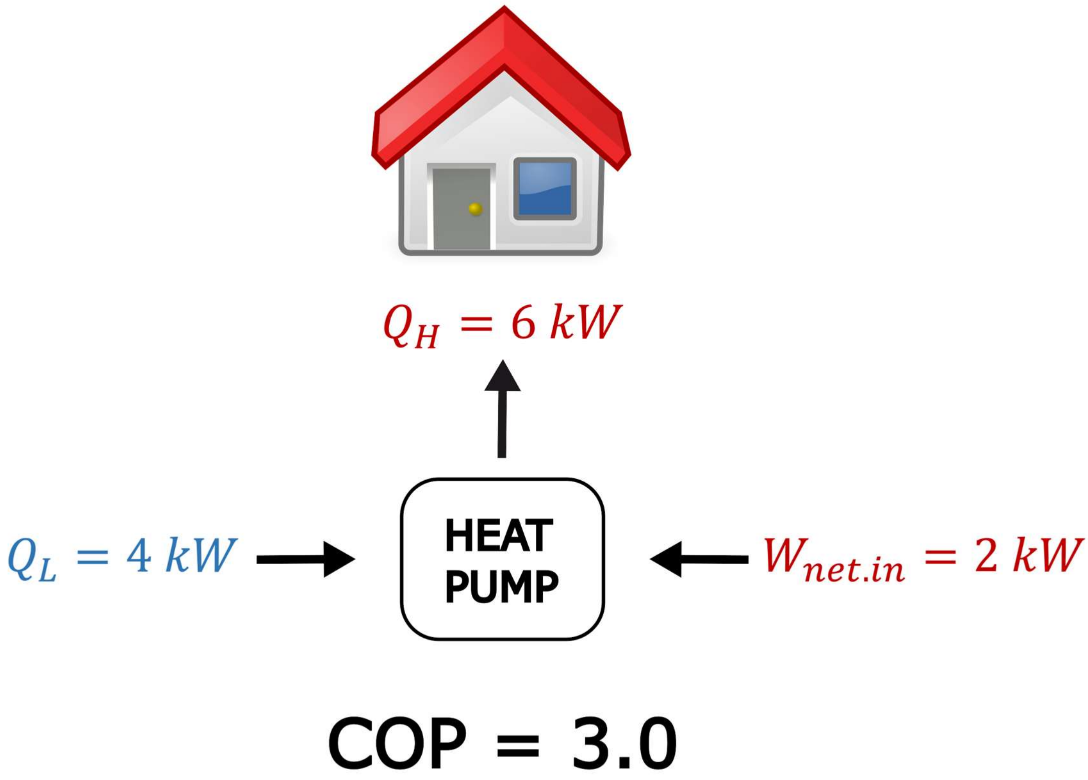


Figure 2-21: Heat pump principle diagram. Credit for "House Icon" SVG-file: OpenClipart [13]

Where $W_{net.in}$ is the energy put into the heat pump from the grid, Q_L is the energy that the heat pump draws in from (relatively) cold outside air, and Q_H is the heat which is delivered to the house. The heat put into the house, is 3 times as high as the energy that is put into the heat pump. This is the fundamental functionality: To "pump heat" from a cold medium, into a hotter one (hence its name).

In the figure we have $Q_H = Q_L + W_{net.in} = 2\ kW + 4\ kW = 6\ kW$. In reality though, some of the $W_{net,in}$ would be lost. (All of it going into the house in the figure, is a simplification.) But the principle remains as follows: The heat pump provides more heat energy than $W_{net.in}$, and the factor of which it does this is called the COP (Coefficient of performance). It is defined as such:

$$(COP) = \frac{Q_H}{W_{net,in}} \tag{2-10}$$

Where the COP will be in parentheses for use in equations in this text, to make it clear it is not a product of C, O and P.

This COP-value will depend on several factors. The quality of the heat pump, and its type of source (air, water, or ground) are design choices affecting this. And so is the output medium (or, the heat sink), and the design output temperature into that medium.

Beyond that, its coefficient of performance will vary depending on the source temperature, and the required heat output and temperature. The first varying with weather/climate conditions, and the second varying with heat demand.

2.9.2 COP-data

For use in this project, COP-data from the when2heat dataset was used. This is an open-source data set, which contain calculations (estimations) of the COP for 28 European countries, in an hourly resolution, from 2008 up through 2022.

Since the later described optimization models worked with a half-hourly time-period, the data was smoothed by every other half-hour being the average of the one before and after it.

Using this data is off course an approximation of what would have been. The data is linked to the heat demand, and so is indirectly the electricity pricing data. However, the two weren't in every case available for the same years. And more so, the COP data were based on nation-wide aggregates, which naturally differs from the exact locations and heat demands for our case studies [105]. But it is considered a fair enough approximation of actual varying COP-values for the coming case studies. The authors provided the following references to the data descriptor of their original data-set, and their working paper about recent updates or extensions of the dataset: [106], [107].

2.10 The Value of Stored Energy and Recovered Heat in a HESS.

Due to the fact that only the heat from the fuel-cell gets its value multiplied by a pricing-ratio, as well as COP-based pricing dividing the value of sold heat, the actual value of stored energy in a HESS (Hydrogen Energy Storage System) with heat recovery is different than it is for batteries. For batteries, the energy is lost according to the round-trip efficiency. But the picture is more complex for a H_2 storage and CHP. This section will present some concepts that can help understand this picture.

2.10.1 The Effect of Heat Pump COP on the Value of HR

When heat pumps are introduced, the value recovered through heat by-product utilization is essentially lowered by the COP, and effectively one gets "less back" from heat recovery. The heat pumps coefficient of performance divides the cost of heat with itself.

For the energy storage system, a concept arises of "value ratio", or "stored energy value ratio", as a function of COP-values, as well as the pricing ratio r_{price} that arises between the time charging and discharging. In the context of the simplified modelling used here, the variables discussed in this chapter are all considered between two discrete time-points in the model.

This "stored energy value ratio" mirrors the "economical energy-efficiency" of the system. If you put 1 unit of investment into charging the system, this is what you get out on the other side economically. Multiplying it with the energy throughput, gives the "profit".

Its value for the H_2 storage and CHP system, is derived from the energy efficiencies, pricing ratio and COP-values. The left-hand term is the return from selling electrolysis heat, and the right-hand term is from selling fuel cell output.

$$r_V = \eta_{DHN} \frac{\eta_{QELY}}{(COP)_{buy}} + r_{price}\eta_{ELY} \left(\eta_{FC} + \eta_{DHN} \frac{\eta_{QFC}}{(COP)_{sell}} \right) \tag{2-11}$$

Where r_V is the ratio of the stored energy value. (Input value vs. output value.) Where r_{price} is the pricing ratio between the half-hour the energy is bought, and the half-hour it is sold. Notably, it is only the fuel cell output (and not the electrolysers), that gets multiplied by this.

To visualize the effect that heat pump COP values has on the value of the stored energy Figure 2-22 and Figure 2-23 below show them plotted for a constant r_{price} of 2, for the conservative and optimistic system respectively. The height of the blue line relative to the red one, represents how the HR-contribution to the value of the stored energy. (For a single charge/discharge cycle.)

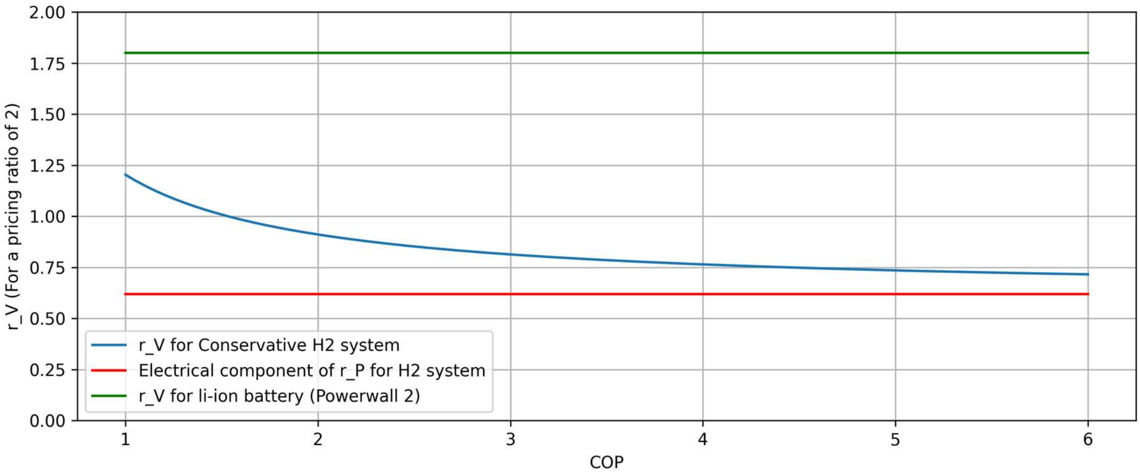


Figure 2-22: " Value Ratio" of conservative system, as a function of COP (for a pricing ratio of 2)

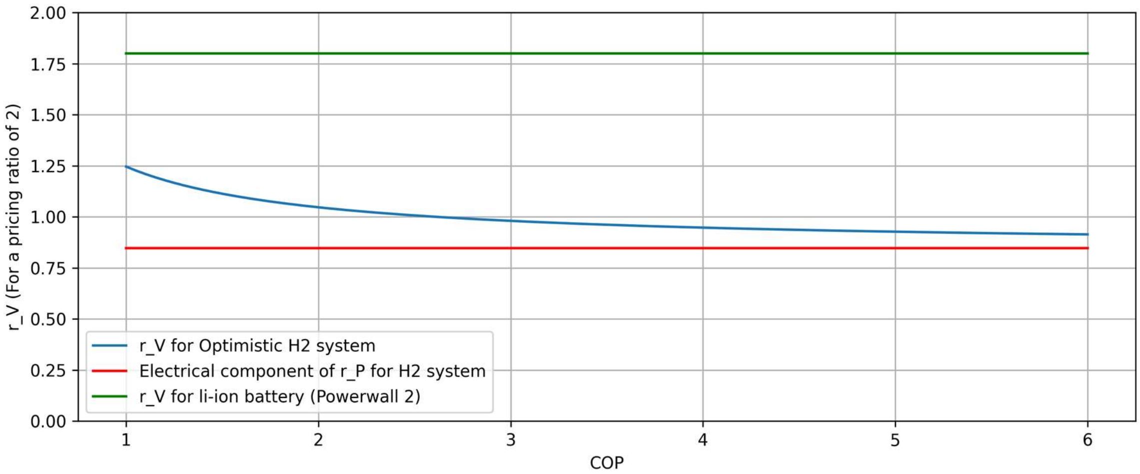


Figure 2-23: "Stored Energy Value Ratio " of futuristic system, depending on COP (for an example pricing ratio of 2)

The green line is for a li-ion battery, which can be seen to have an r_V equal to its RTE times the pricing ratio. For batteries, we have:

$$r_V = \eta_{RTE} r_{price} \qquad \text{(for fully electrical batteries)} \tag{2-12}$$

Where η_{RTE} is the round-trip efficiency of the battery.

Meanwhile, the H_2 system has an RTE of about 0.7. However, its starting point at Joule-based heat pricing (COP = 1) is however still lower than 0.7*2 = 1.4 above. This is due to the fact that the heat recovery from the electrolyser is sold at the same price as energy is bought. Thus, it is only a recouperation on charging costs. It does not take advantage of price-increases, as is done by the heat recovery and electrical output from the fuel cell, or the full throughput of a battery.

(The change of COP between time-points is ignored in this discussion for now, in order to focus on one and one aspect. The COP will change quite randomly but stay around roughly the same value.)

The higher the pricing ratio r_{price}, the larger this initial difference is. At an r_{price} of 1, the stored energy value ratio for a Joule-based heat price, is equal to the round-trip energy efficiency for both the systems. However, this is irrelevant, as the system will never charge at a pricing ratio of 1. Thus, the systems RTE does not represent its performance potential in the same way as it does for a battery.

And, when introducing r_{price} the distance between the blue line at COP = 1 increases. (See the leftmost values in the plot of Figure 2-22) The term not multiplied by r_{price} (the contribution of the electrolysers HR) becomes insignificant as r_{price} goes to infinity. Which it can do, as electricity prices go near zero or even negative. We are then left with the right-hand side term being the only contribution to the stored energy value ratio for the H_2 system.

On top of this, the value of the heat recovery is reduced from being divided by the COP. It reduces reciprocally as the COP increases. Even for a COP value of 2 (which is what one might find in the very coldest environments heat pumps can operate) the total heat recovery contribution is halved (as seen clearly by the heat terms in equation (2-11). Or for the case study in London, the weighted average COP is 3.3, which means that the contribution of HR is on average reduced to 30%, of what it would be with resistive heating.

The system will only operate, if it can find two time-points for which r_V is greater than 1. And, since η_{RTE} cannot be used together with $r_{price}$to determine r_V, as it can for batteries, a new measure will be introduced to assess the energy-economical performance of the H_2 system.

2.10.2 The effect of price ratios

How much larger r_V is than 1, determines how much profit is made per throughput of energy that the system has. As per equation (2-13) below.

As seen in Figure 2-22 above, it is significantly a lot lower for the H_2 system than the battery one. Here, the H_2 system isn't feasible at all when the average 3.3 COP is applied. It's r_V is lower than 1. However, the above figures are for an r_{price} of just 2. Values similar to this or even lower, can be found on many days in some years (e.g., 2019). However, for some years the ratio is considerably higher, and even intermittently goes to infinity (due to prices actually being negative every now and then).

The concept of a "pricing ratio performance factor" can be analysed. It describes performance of an energy storage system, as a function of the price ratio. Performance here being the profits made in between two time-points in the model.

To derive it, we start with the equation for the profit depending on the energy throughput between two time-points:

$$K_{CycleProfit} = (r_V - 1)E_{throughput}C_{elec} \tag{2-13}$$

$$= \left(\eta_{DHN}\frac{\eta_{QELY}}{(COP)_{buy}} + r_{price}\eta_{ELY}\left(\eta_{FC} + \eta_{DHN}\frac{\eta_{QFC}}{(COP)_{sell}}\right) - 1\right)E_{throughput}C_{elec}$$

Where $K_{CycleProfit}$ is the profits, $E_{throughput}$ is the energy charged, and C_{elec} is the price at the time of charging.

The "pricing ratio performance factor" is defined by the following:

$$K_{CycleProfit} = r_P r_{price} E_{throughput} C_{elec} = (r_V - 1)E_{throughput}C_{elec} \tag{2-14}$$

$$r_P r_{price} = r_V - 1 \tag{2-15}$$

It describes the relationship between r_{price} and the profits obtained through a charge/discharge cycle. For a battery, this can be stated quite simply:

$$r_P = \frac{\eta_{RTE} r_{price} - 1}{r_{price}} \tag{2-16}$$

For the H_2 it is not as straightforward. Substituting its expression for r_V into equation (2-13) and solving for r_P yields:

$$r_P = \frac{\eta_{DHN}\frac{\eta_{QELY}}{(COP)_1} + r_{price}\eta_{ELY}\left(\eta_{FC} + \eta_{DHN}\frac{\eta_{QFC}}{(COP)_2}\right) - 1}{r_{price}} \tag{2-17}$$

This represents the value with which to multiply $r_{price}E_{throughput}C_{elec}$ in order to get the "performance" of a single cycle. r_P is seen as a property of the energy storage system depending on r_{price} and the COP. Since it is a function of two things, plotting it can only be done with a heatmap or in 3D. However, below it is plotted for a constant COP of 3.3 to illustrate things more clearly. Also being plotted only for positive r_{price} values. The equation for $K_{CycleProfit}$ also hold for negative r_{price} as it is cancelled out by a negative C_{elec}. But considerations around this are looked away from in this discussion to keep things shorter and less cluttered.

Figure 2-24 and Figure 2-25 below show r_P for Joule-based pricing and COP-based pricing respectively. It can be seen that the systems are closer to each other for Joule-based pricing.

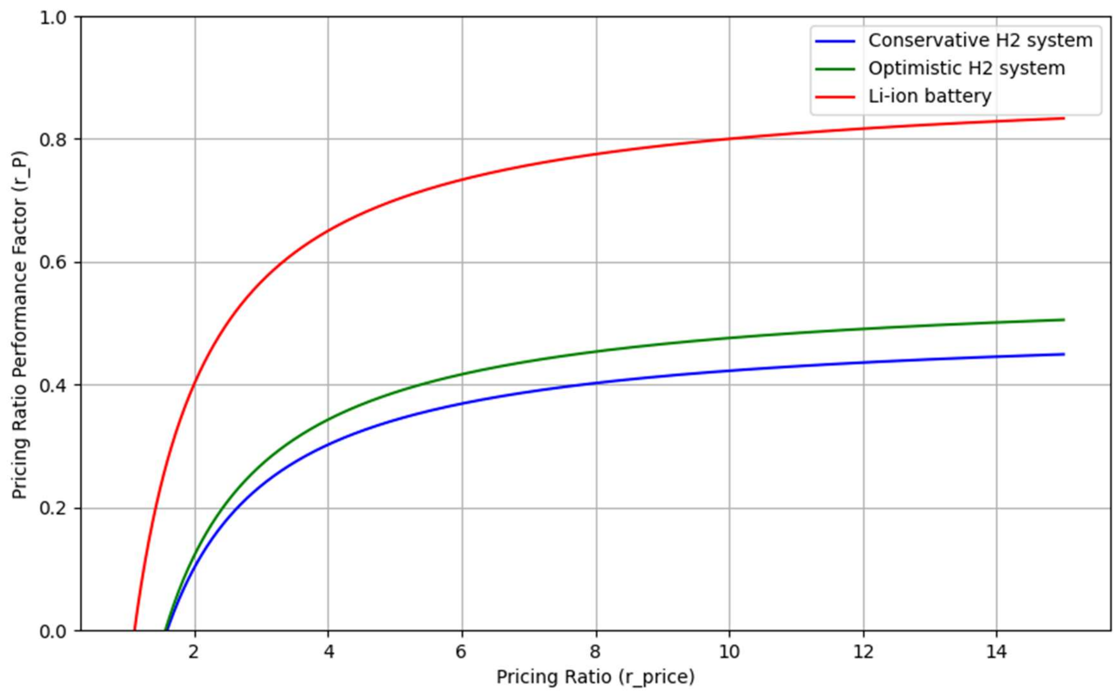


Figure 2-24: Pricing ratio performance factor of the H_2 system (Joule-based heat pricing).

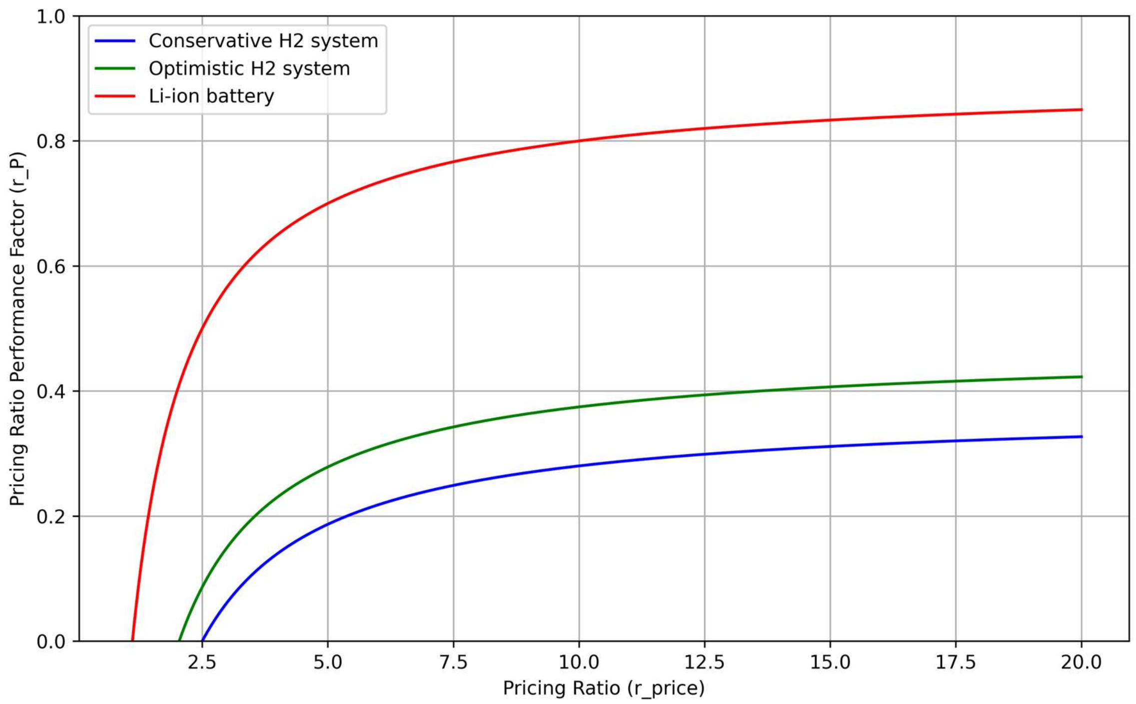


Figure 2-25: Pricing ratio performance factor of the H_2 system (Heat pricing for a typical COP of 3.3).

Re-iterating that the profits between two time-points is:

$$K_{CycleProfit} = r_P r_{price} E_{throughput} C_{elec} \tag{2-18}$$

One can consider this, in order to describe some characteristics of the different H_2 systems. A first note can be that r_P is a system characteristic and a function of r_{price}. Upon this however, one has that the obtainable r_{price} and $E_{throughput}$ are highly affected by systems operational patterns (how much and when it charges and discharges). Which again is affected by its capacities such as charge/discharge power and storage capacity.

For Joule-based heat pricing, as r_{price} becomes high, the system performance factor r_P approaches the round-trip energy efficiency of the systems, but minus the electrolyser HR-contribution for the H_2 system. Furthermore, when a COP higher than 1 is introduced, r_P is decreased further down towards its electrical RTE for the H_2 system.

This is also evident from equation (2-18) where we see both the electrolyser HR component and the -1, become insignificant when r_{price} becomes large, leaving us with the expression for the fuel cell only.

The most important observation from the plot in Figure 2-25 , is that the H_2 system has a very severe disadvantage at lower pricing ratios. It needs a higher pricing ratio to be able to obtain profitable charge/discharge cycles to begin with. Shown by where its line enters the plot on the r_{price} axis. And furthermore, it also rises more slowly after entering the plot. Before ending up at its optimal r_P only with very high pricing ratios. Which still is considerably lower than that of the Li-ion battery.

It can therefore (due to the values seen in Figure 2-25) be predicted, that the H_2 storage and CHP system will not stand a chance at being feasible when pricing ratios are low. In fact, only with very high pricing ratios can it hope to be competitive. If these ratios do occur, the question regarding the H_2 system's feasibility, is whether it can obtain a combination of $E_{throughput}$, r_{price} and C_{elec}values, that make up for its lower r_P.

In other words, its $r_{price}E_{throughput}C_{elec}$ has to be much greater than that of the batter, in order to weigh up for its lower r_P. This is what this thesis aims to investigate:

Can H_2's vastly cheaper storage together with its modularity of capacities, allow it to achieve this to a sufficient degree to counteract its lower r_P, compared to a battery-system?

This is what the optimization model and capacity allocation algorithm will be used to find the answer to. Through establishing set of capacities that are optimally adapted to achieve the best combinations of r_{price}, $E_{throughput}$ and C_{elec} over all the time-points of the year, and then finding the performance of that system.

However, it is evident from the r_P values found in Figure 2-25, that in order for it to have any chance of making up for its inferior r_P value, it will need to operate in an environment with high r_{price} values. Such as the 2022 and 2023 datasets for pricing.

3 Methods

This chapter will give an overview of the methods used. Introduction to the general theory and description of methods used elsewhere in the thesis.

3.1 Linear Programming

Linear programming is used to find the optimal solution to a problem, where the objective function (the function describing the thing that one wants to maximise or minimise) as well as the constraints, are made up of linear terms.

If they are, one can use a linear solver to find an optimal solution. To do this, the mathematical model has to be stated, together with parameters (such as data and other constants). This is done using the python module Pyomo for this thesis. A third-party solver then solves the problem and returns the optimal solution. Gurobi was used in this case. The code for the optimization models and all other code in this thesis, is found in Appendix A.

In the case studies, the objective function was to minimize operational costs. To minimize the capital expenditure on energy throughout the year. This problem is solved by finding the values of the model's variables, that gives the optimal value in this sense.

This solution represents when and to what degree to operate the components of energy systems. E.g., when, and how much to charge and discharge energy. All of these values are averages for the time-units that the model is working with. For example, half-hours (case 1) or hours (case 2).

The solution of a variable P^{i}_{charge} is then a solution for an array of for example $i = 8760$ values, one for each hour of the year. From the solution of these variables, derived values such as the money spent on charge, can be calculated, by multiplying and summing P^{i}_{charg} and C^{i}_{elec} for every i the model operates.

The main result from the model was a simple performance-measure: "Money saved" for case 1. Or "money spent" for case 2. Along the way however, looking at graphs of charge/discharge patterns was also useful for interpreting trends about the systems operation. Figure 3-1 below shows an example of this. The blue line is the charge state (a variable the model has solved for), and the yellow line is the electricity price. It can be seen that it charges at times of low pricing, and discharges at high prices.

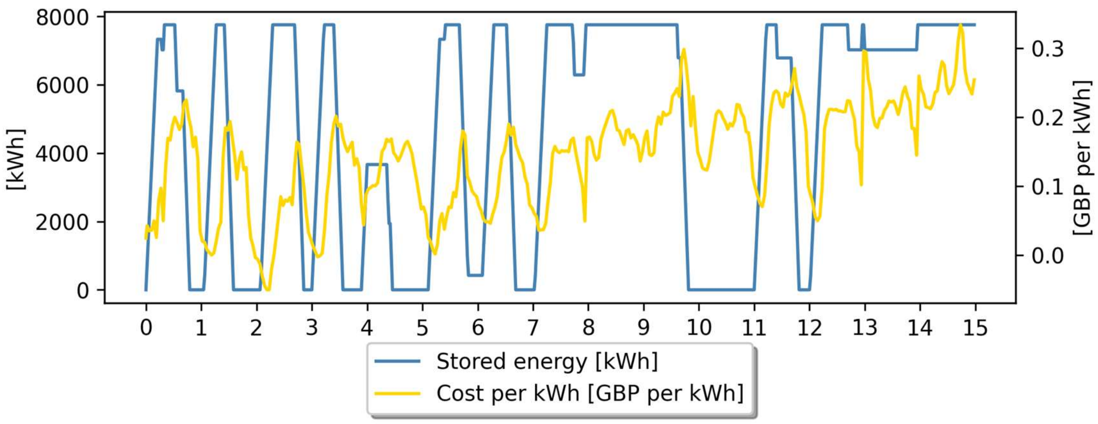


Figure 3-1: Figure 3 1: Output of LP example. 15 Days of system operation (together with energy cost).

Several results from the model and their derived values were found useful. Things like the total energy throughput, the money saved by electrolyser HR vs. fuel cell HR, charge/discharge, and many others can be derived. Although, the time to analyse or write about all of this was limited, and the thesis here focuses on the contribution of HR. But undoubtedly, modelling the system behaviour can be very useful for obtaining data towards lifespan analysis or components and the impacts of different system aspects.

One generally want to find only the necessary variables, and to make others "deferred" if possible, in such a model. This makes for a faster solve time. Although the model solved in 5 – 15 seconds or so, this would add up greatly when running it hundreds or thousands of times, when generating plots for different system capacities.

Some further variables to be solved for were however needed added compared to a simple battery. Due to the nature of the H_2 system. The energy streams were split between electricity and heat variables, to allow for calculating their respective different costs, as well as opening for the system modulating the electricity import/export while keeping tabs of the heat recovery, and the potential curtailment of that in the few cases where it was found profitable to do so.

The mathematical formulations of the optimization models, are stated in their respective case study chapters. The python code implementations can be found in Appendix Aoptimize_oes.py in Appendix A.

3.1.1 Inaccuracies and simplifications with open-loop linear programming

Linear programming (LP) is used. This means that it requires using a simplified view of the system, where the way it works fit into being described by linear terms. More so, we are using open-loop LP, which means that we assume perfect foresight.

It solves for optimizing the operation of the system (e.g., when to use electrolysers and fuel cells), based on having all information into the future when it comes to pricing and demand etc. Obviously, this will produce a better outcome for any system, than the one that actually could be achieved with real-world limited foresight regarding this information.

The result becomes the optimal solution when all time-points across the whole year (in this case) are considered. This can be seen as the theoretical upper bound for the actual operational performance.

When it comes to the actual prediction of these data, demand can be roughly predicted based on historical data and weather and temperature forecasts. Pricing is often given for day-ahead markets one or two days in advance, but pricing forecasts farther into the future can likely be very uncertain. How the system would actually decide its operations is not within the scope of this thesis. Only establishing the mentioned theoretical upper bound that would arise from perfect operation is.

How close actual operational efficiency could be to reaching this upper bound, depends on how good the system that controls the system is. A combination of closed-loop (rolling horizon) and machine learning/AI employing weather forecasts and a multiple of different variables, could be employed. But no matter their success, the efficiency of operation will naturally be quite a bit lower than that which the deterministic, open-loop optimization produces.

One important remark regarding this, is that it will be a lot easier to achieve closer results to the open-loop operation, for a system adapted to daily storage. As opposed to one adapted to long term or seasonal storage. This would be mostly due to day-ahead prices being available, as well as accurate assumptions on heat demands. This means that the results form an open-loop optimization are likely farther from actual achievable results when it is used on a system with a large storage capacity that takes advantage of seasonal price variations.

As mentioned, any thought to the magnitude of this discrepancy is not within the scope of this thesis, but the reader is asked to keep in mind this difference between the systems that are more seasonal in their operation, vs. those that operate more daily.

Specifically, li-ion battery systems are innately suited to daily operations, due to their relative low storage capacity to power ratio, and low scalability in this aspect. Whereas H_2 for example can be freely scaled for these capacities.

The allocation of resources towards large storage capacity for the H_2 system however brings with it new potential market possibilities and use-cases. (E.g., providing needed seasonal storage, or absorbing surplus from sources with more long-term variations such as wind and hydropower. Which could be awarded through certain incentives or market schemes.) Direct exploration of this is however outside the scope of this thesis, but it was mentioned as a counterweight to the disadvantage large-capacity storage has in terms of daily operations only.

Lastly it can be mentioned that certain system behaviours that aren't linear, are also simplified in order for them to fit within LP optimization modelling. The inaccuracies from this are assumed to be small enough to consider an LP solution to be considered a good approximation. But these aspects will be mentioned and discussed around the systems in their respective case study chapters.

3.2 H_2 system capacity allocation optimization

After the optimization model that found the optimal operation of the energy storage system in case 1 was developed, a next step was to find a way to determine the optimal system capacities. The combination of charge power, storage capacity and discharge power, for which the optimization model would find the highest "money saved".

The resources to be allocated in order to find this point, was the system CAPEX. To find the optimal set of system capacities for a constant CAPEX, two approaches were developed in python.

The first, was a "capacity allocation algorithm" that iterated itself towards the optimal combination of capacities based on a given CAPEX. This algorithm was conceived from, not based on any previous existing methods or ideas pertaining to this type of case that the author knew about. It is however a basic hill-climbing algorithm, which, as pointed out by supervisor Assoc. Prof. H. Johnsen, is a common concept often used in various applications.

The second script, simply generated results for all possible combinations of system capacities within the given CAPEX and plotted them in order to show the relation between system capacities and money saved.

The hill-climbing algorithm was a tool for iterating towards the optimum set of capacities within a few minutes. The second, was a tool to view the relationship between system capacities and "money saved". This was also developed to confirm that the surface which the hill-climbing algorithm operated on was convex with a single global maximum. Thus, validating that the hill-climbing algorithm would work correctly. The hill-climbing/capacity-allocation algorithm can be found in loop_for_optimal_oes.py in Appendix A, and the surface generation algorithm code can be found in 3D_viewer.py in Appendix A.

3.2.1 The System Capacity Allocation Optimization Algorithm for Case 1

The capacity-allocation algorithm iterates itself towards the highest performing system capacities. In essence, the algorithm is navigating a hypersurface the 4D space (x, y, z, m). The three system capacities and the "money saved" that the optimization model returns for those values.

This could be visualized as a heatmap in 3D space. The three system capacities, charging power, storage capacity and discharging power, are hereby defined as x, y and z respectively. Both when referring to equations and plots, and in the python code. Through the results of the optimization model, they define the position in the 4th dimension, the "money saved", or m.

However, since we are keeping system CAPEX constant we can introduce the following equation, which makes any one system capacity implicit of the other two.

$$C_{ELY}(1 + 0.32\eta_{ELY})x + C_{storage}y + C_{FC}z = K_{investment} \quad (3\text{-}1)$$

Where the total investment for the parts is $K_{investment}$, and the C variables are defined by the cost functions. x, y, and z are defined as charge power, storage capacity and discharge power respectively. Input power, HHV content of H_2 and HHV input to the fuel cell to be precise.

C_{ELY} and C_{FC} are also functions of their respective system sizes x and z. $C_{storage}$ is in this thesis assumed to be a constant. Expressions for these will be established for the relevant components in the case study chapters, and the methodology to do so is presented in section 3.3 below.

Through equation (3-1), we can reduce the dimensionality of the allocation problem. From having a hypersurface in 4D space, we can now reduce it to a surface in any of the 3D sub-spaces of said 4D space. Equation (3-1) above defines a surface in the subspace (x, y, z), but this also amounts to defining surfaces in the other 3D subspaces. For example, as x and z defines y, and x, y, z defines m, we also have that x, z defines m. Thus, we have a defined surface in the space x, z, m as well. Implicitly from eq. (3-1).

Solving for the surface in x, y, z is how the algorithm determines its test-vectors. It will find a set of nearby points in different directions, that is in this plane. By navigating this surface in the (x, y, z) subspace, it simultaneously navigates a surface in the (x, z, m) subspace. It is this surface (visualized in Figure 3-2 below) that the algorithm can be visualized as "hill-climbing".

A reason the extra step of visualizing the problem as a surface in 3D is explained, was so that this visualization could be used to verify that the hill-climbing algorithm would find the maximum. In Figure 3-2 below it can be seen that the surface has a single global maximum (as opposed to having several, or the optimal being outside the feasible domain). Thus, we can know that the algorithm will converge to the optimal capacities.

The surface varies in shape depending on the parameters given to the optimization model, but it has been observed to have this general shape for all tested scenarios. It also is intuitive that it will have this shape, as approaching zero of either capacity will make the system both unable to perform well, as well as returning higher costs per capacity for capacities.

What the algorithm does from start to finish is the following: First, it starts at any random point, defined by an arbitrary x and z value, solving for y. Then it chooses test-vectors a set step-length (given by a ratio, e.g. 1.3) that satisfy equation (3-1). It then it employs multi-processing to run the optimization model for each of these test-vectors in parallel. It then collects the results, chooses the capacities that gave the best results, moves there for the next iteration, and repeats.

This continues, until the step size makes the test-vectors overshoot the optimal point to such a degree that it can't find a better result than it had. At which point the step size is reduced. Enabling the algorithm to find the optimal set of system capacities eventually. Terminating, once the step-size is below a certain threshold.

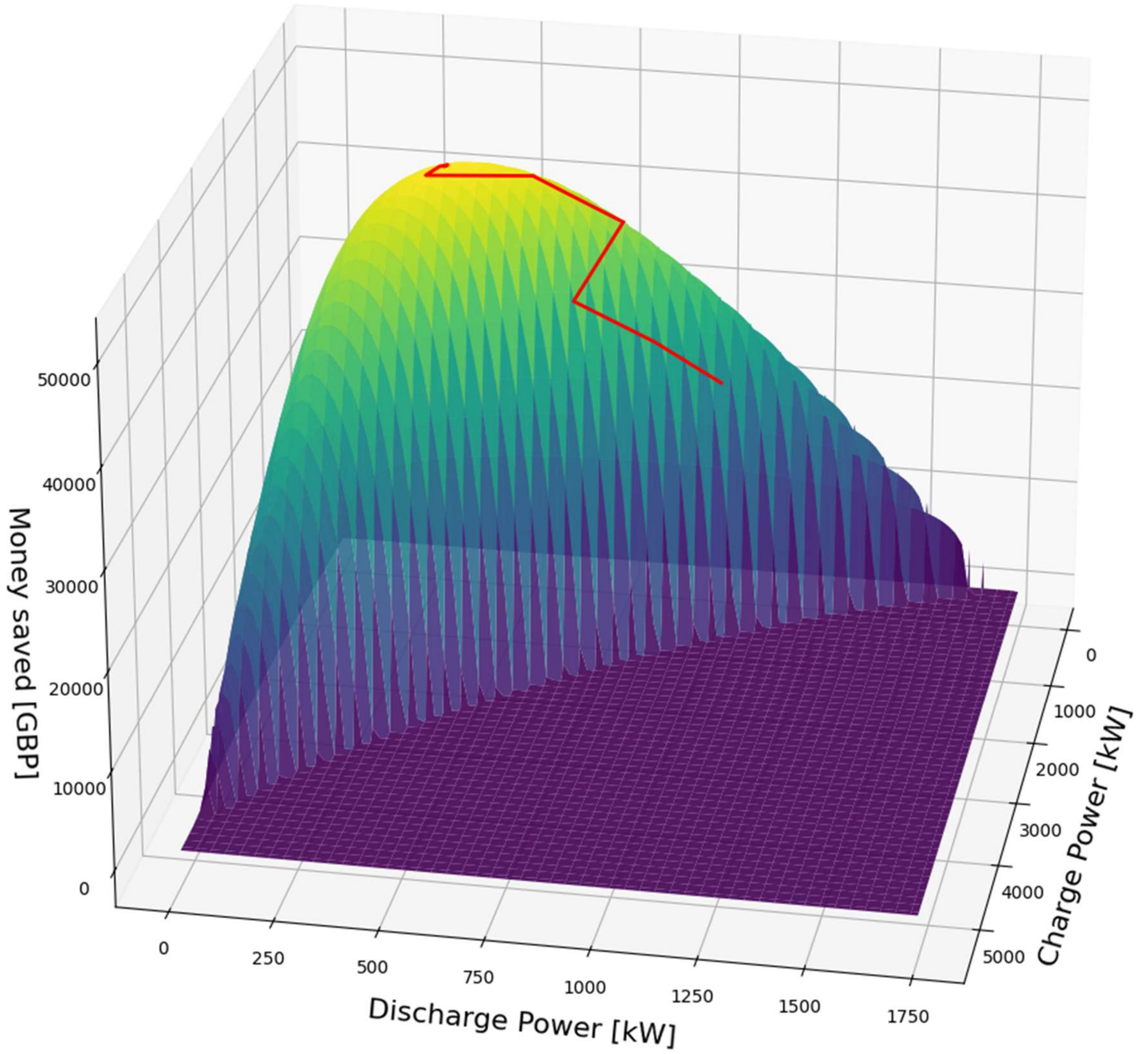


Figure 3-2: Money saved as a result of charge and discharge power. With algorithms path to maximum.

As mentioned, this was developed from the ground up, supervisor Assoc. Prof. H. Johnsen pointing out that this is a general concept used for various applications. It was however not put any emphasis into developing this algorithm into a state-of-the-art version of itself for this project or doing any in-depth research on how others have approached similar methods. If it was to be improved, the first step the author would do, would be to investigate generation of more efficient test-vectors. However, the algorithm was seen as serving its purpose sufficiently as is for the current application. Potential room for improvements is acknowledged.

The demonstration run of the algorithm visualized in Figure 3-2 above, started with a ratio of capacities that is similar to what might be found in a typical li-ion battery (3.3 times the storage in kWh as power in kW). The red line visualizes its path to the top. In this example, with this starting point, it used a single-digit number of steps to get within 1% of the optimal solution, and the system performance (money saved) was doubled from its starting point. (The plot was of an early test-run for method validation, not necessarily representing the final model.)

The hill-climbing algorithm used a bit over 2 minutes to find the top (each step running the optimization model 6 times). The generation of the surface, however, can take hours, depending on resolution and processing power.

This demonstrates that potentially large gains in performance can be found by optimizing the proportions between the system capacities. All subsequent mentions of an "optimally allocated H_2 system", refers to a system that has had its capabilities allocated to the optimal configuration for its pertinent year of operation, by this algorithm.

3.2.2 Mass generation of results from all possible configurations

The hill-climbing algorithm was made for frequent use, to enable quickly finding the optimal combination of system capacities while looking at the numerous scenarios in case study 1. The script that generated the full surface on the other hand, runs the optimization model (parallelized) for all feasible combinations of two system capacities. For example, charge power (electrolyser) and discharge power (fuel cell).

It was at first developed to verify that the hill-climbing algorithm would work. Through the observation that the surface is convex, with a single global maximum. However, it can also be a useful tool for analysis or system design.

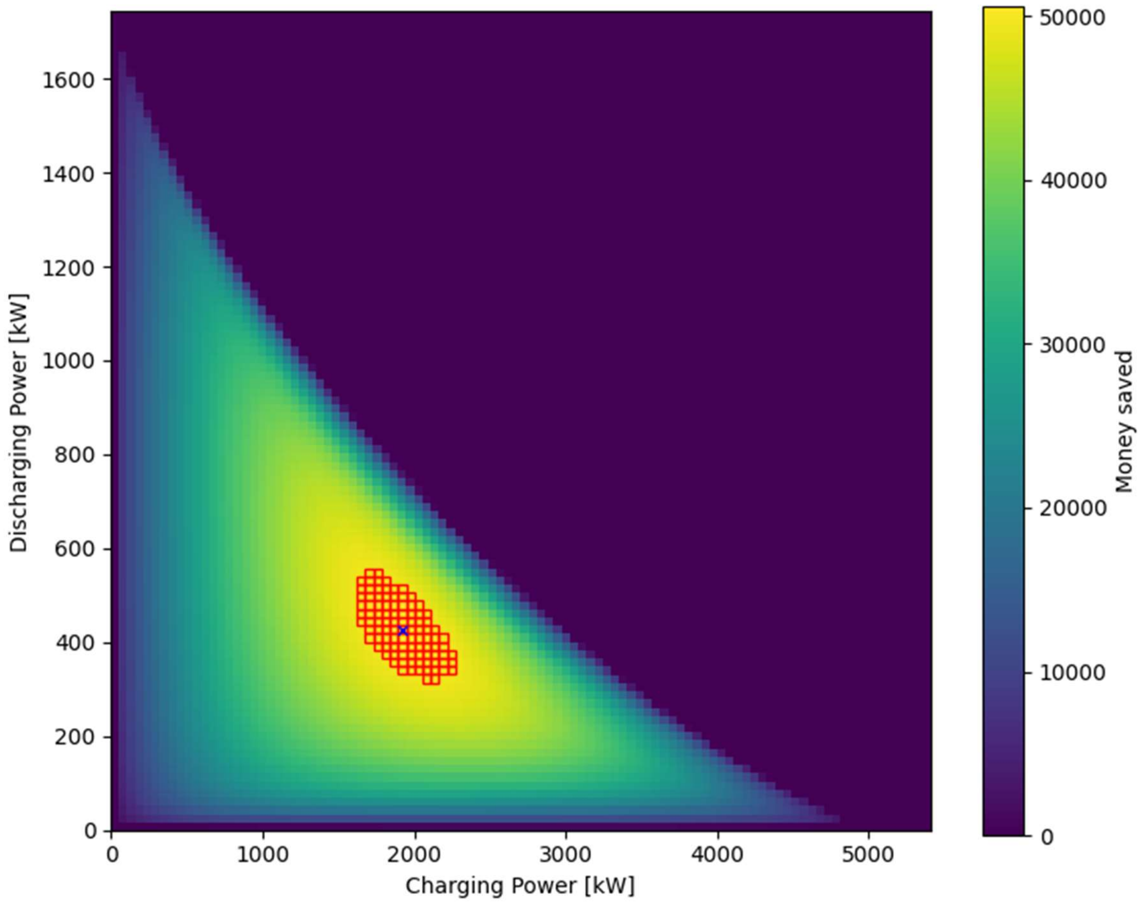


Figure 3-3: Heatmap of money saved on the plane of discharge power and charge power

Figure 3-3 above, shows the 2D heatmap of money saved, with the top 2% in red and the maximum marked with a blue X. As can be seen, a relatively wide range of system capacities can be chosen to achieve very close to optimal system performance. Through this, one could for example choose the set of capacities within a certain threshold from the top, which is best suited to practical implementation or using available off the shelf components.

While this plot takes up to hundreds of times longer to generate than the hill-climbing algorithm takes to converge (depending on resolution and CPU core count), the run-times are still reasonable enough for it to be a usable tool. Although running it for every scenario in case study 1 would have been very impractical, thus the hill-climbing algorithm was developed for that purpose.

3.2.3 Inaccuracies of the capacity allocation methods

In-accuracies must be taken into consideration when assessing results from this tool. More definite results can only be achieved using a MILP (mixed integer linear programming) model that had actual unit-prices for off-the-shelf as parameters. However, future pricing on actual off-the-shelf units from 2030 and beyond is naturally not possible to determine at this point. The cost functions is the best approximation available of this. More so, considering the top of the surfaces (like those in Figure 3-2 and Figure 3-3) are quite flat near their maximums, it is likely that some off-the-shelf components within a low threshold from the top will be available.

It mainly then depends on the accuracy of the cost functions themselves. If they are in-accurate, the above methods will produce configurations of the system that represent higher or lower capacities than would actually be possible to achieve. However, the cost functions are the best estimations that was found for this thesis, and such estimations is needed to be able to configure a realistic system config. based on a CAPEX at all. It is thus seen as the most pragmatic and realistic way possible for defining the system configurations that a given CAPEX would produce.

3.3 Cost function methodology for Hydrogen Components

The algorithm that produces the optimal set of capacities, needs functions for the C-variables in equation(3-1) . Without this, there is no knowing how much improvement the H_2 energy storage system could really achieve through allocating its capacities, so even if cost functions are approximations, it is seen as better to use them than to choose arbitrary system capacities to investigate HR contributions for.

The methodology for obtaining these cost functions is described in the following sections. For the electrolyser, an established methodology was found, however, more approximate methods based on assumptions were adopted for other components.

3.3.1 Cost function for electrolysers

Reksten et. al. proposes the following equation for a non-linear least square fitting of AEL and PEMEL costs as a function of system size:

$$C = \left(k_0 + \frac{k}{Q} Q^{\mathrm{a}}\right)\left(\frac{\mathrm{V}}{V_0}\right)^{\mathrm{b}} \qquad \textit{(3-2)}$$

Where C is the cost per capacity, V stands for the year in question, V_0 is the reference year (here 2020), k, k_0, α and β are fitting constants. Which, when fitted to the data in Figure 3-4 below, gives the parameters shown in Figure 3-5.

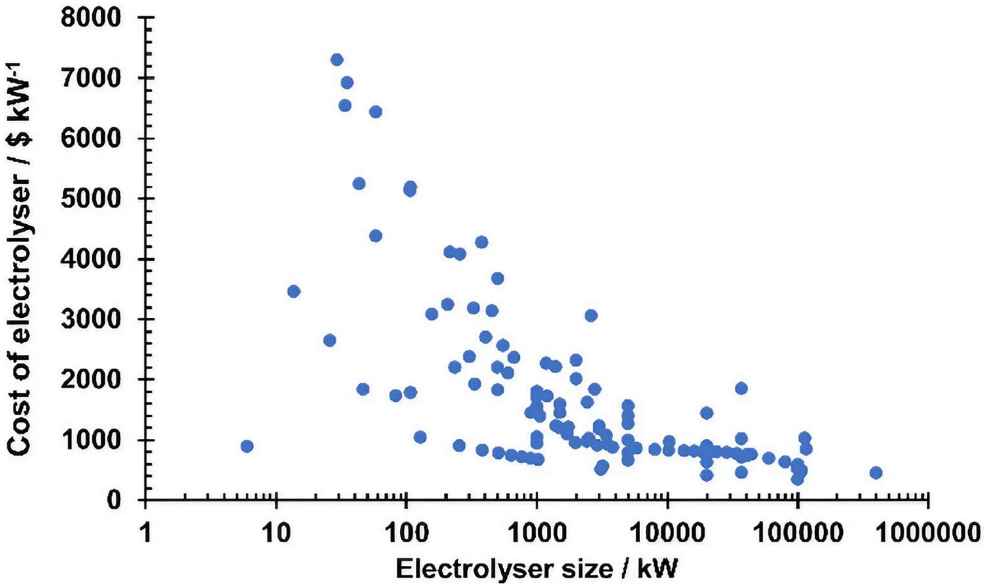


Figure 3-4: Data for electrolyser cost per capacity, by system size. Image Credit: Reksten et. al. [79, p. 38109]

Table 1 – Projection parameters from the non-linear least square fitting for AEL and PEMEL.

Parameter	AEL	PEMEL
α	0.649	0.622
β	−27.33	−158.9
k_0	301.04	585.85
k	11,603	9458.2
V_0	2020	2020
SE	547	510

Figure 3-5: Projection parameters for AEL and PEMEL for equation (3-2). Image Credit: Reksten et. al. [79, p. 38110]

This function plotted (by Reksten et. al.) for AEL and PEMEL technologies, in 2020 and 2030 respectively, is shown in Figure 3-6 below.

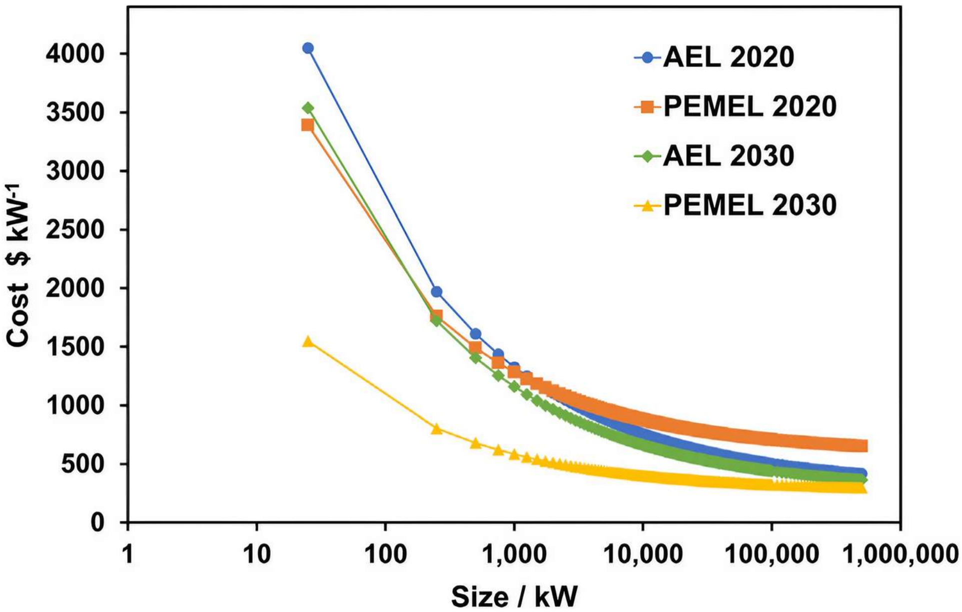


Figure 3-6: Cost per kW, depending on system capacity in kW. Image Credit: Reksten et. al. [79, p. 38110]

It is seen that the cost per capacity changes drastically with the capacity of the system. This has to be taken into account when dimensioning the system for case 1, as in allocating CAPEX to the different components/capacities of the system. As in charging power (electrolyser), storage (tanks) and discharging power (fuel cell).

At first, a linear relationship based on USD/kW were considered, but this is much too inaccurate unless dealing with small domains in the several mega-watt class. Low-capacity systems would also have been over-estimated through the algorithm trading electrolyser and fuel cell capacities for extreme/unrealistic amounts of storage.

Whereas these equations are not pin-point accurate, as seen in the data presented in Figure 3-4, they are seen as providing a reasonable approximation of what costs one can expect to find in a future 2030+ market.

For pinpoint accurate results relative to CAPEX, one would need data from the actual 2030+ component marketplace, and feed these into a MILP (mixed-integer linear programming) model. However, 2030+ component pricing is naturally not available as of now, and the above is thus seen as the best approximation available.

Figure 3-7 shows the plot of the Reksten et al. function, together with the power series trend-line of its point (dotted blue for all points, and dotted burgundy for two points). Notably, for a small, case 1 adapted system size. The curve fit was done for a much larger domain for case 2.

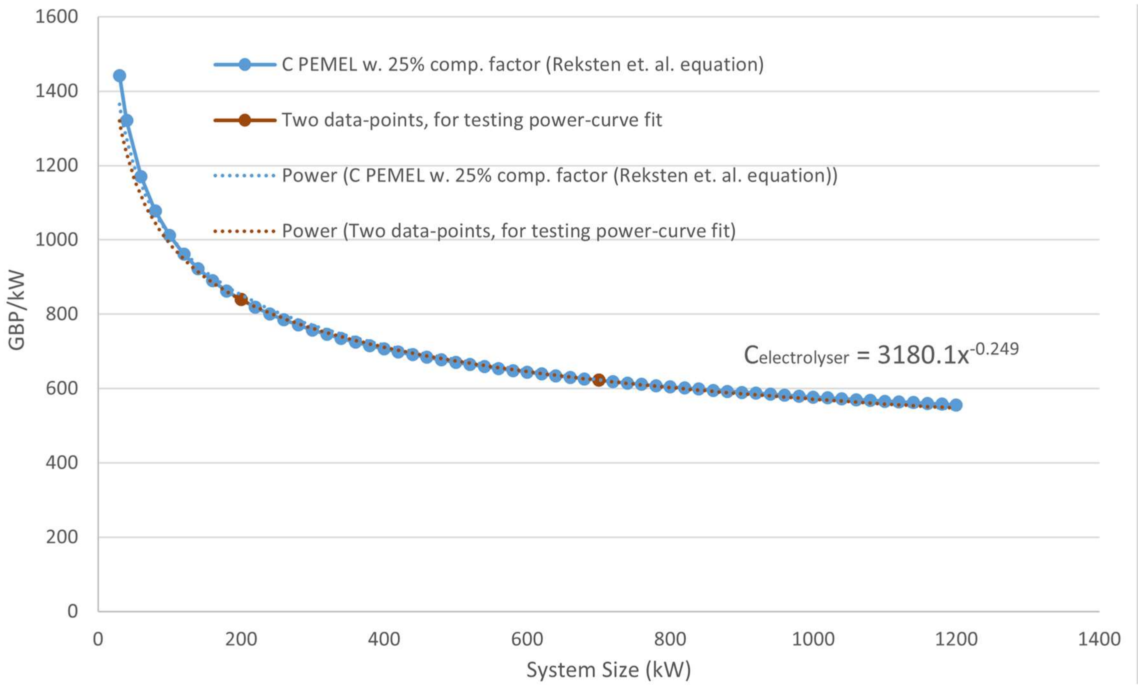


Figure 3-7: Cost per capacity, as a function of system size (for PEMEL, including compressor) [(GBP/kW)/kW][1]

The work that Reksten et. al. did on fitting equation (3-2) to electrolyser pricing data, is however not done for fuel cells. It is however seen, that a power series trendline, is a good approximation for their equation, even with a few data-points.

For this thesis, the manufacturing economics for PEMFC devices is approximated to be at least to some degree similar in nature to that of a PEM electrolyser. A similar cost per kW relationship will be established for fuel cells as well.

Figure 3-8 below shows the curve for a PEMFC device based on three data-points.

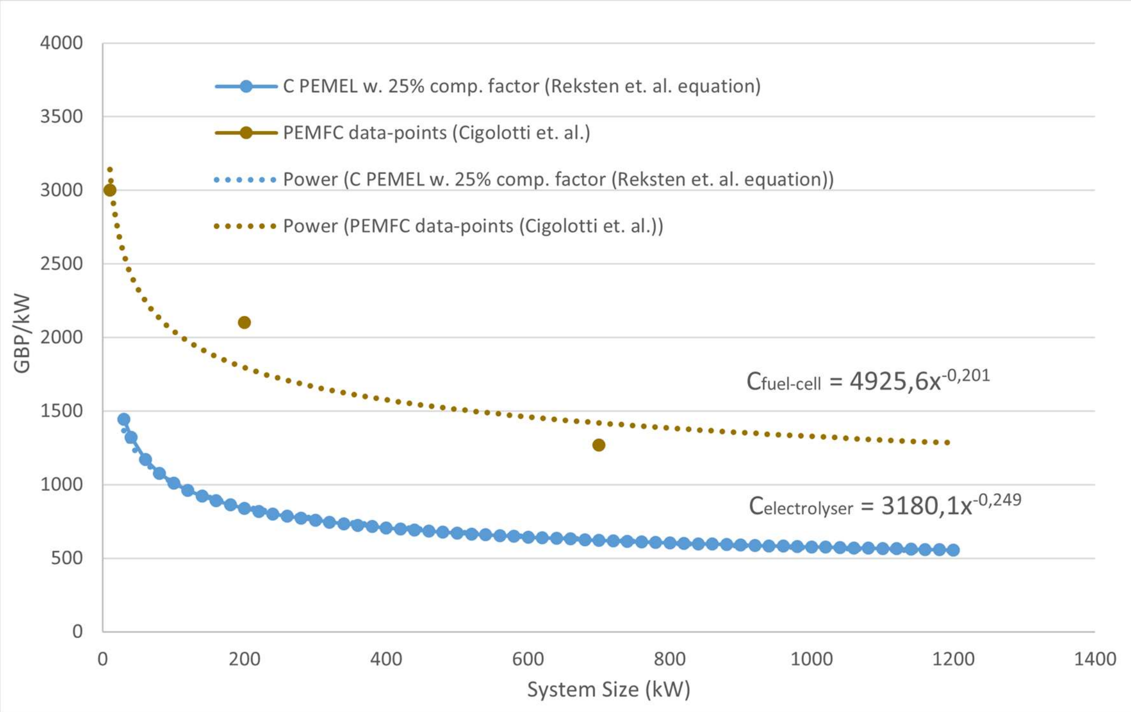


Figure 3-8: Functions for fuel cell (gold dotted line and three data-points) and electrolyser (blue lines)

It must however be said that only three data-points does not give great confidence. However, surprisingly few sources were found with consistent data for FC cost based on system size. An attempt to get a better foundation should be done if possible and/or re-using an approach like this. However, for the application at hand, estimating HR-contribution, the above is considered a fair approximation.

For EHC and storage tank costs, different approaches than the power trend-line fit will be used. The underlying discussion on this is found in Appendix B (ref. its own table of contents). But in short, the EHC is included as a factor $C_{ELY.Reksten}(1 + 0.32\eta_{ELY})$. The EHC cost is considered bundled with the electrolyser into the function used in the algorithm.

This is likely the most error prone part of the cost function estimations. It is done in lack of better resources on the area, considering that EHC is a nascent technology with too little data available for a proper curve fit.

When it came to storage tanks, their total cost was assumed to have a linear relationship with overall capacity. Considering the high number of small size gas bottle units being, as well as the high material costs of those units.

Overall, the cost function approximation methodology is something that has innate uncertainty, on top of being an approximation (vs. using a MILP method) in the first place. On the other hand, it is necessary to approximate them, in order to be able to establish a logical/optimal system configuration at all.

Mostly however, inaccuracies in cost functions will affect the inaccuracy as to what CAPEX the system really represents. It will likely not have major implications for the results regarding the contribution of HR.

Due to the flatness near the top of the "performance surface" (as seen in Figure 3-2 and Figure 3-3), we saw that a rather generous part of the domain was close to maximum performance. What the thesis seeks to do is to find the HR contribution of a configuration that is approximately within this region. In other words: To find the HR contribution of system configurations that are reasonable and realistic for this type of system.

What an inaccuracy in the cost function will do in regard to affecting results on HR contribution, is essentially to move this area and thus give an unrealistic system configuration for which the optimization model is run. But since the area near the top of this surface is this flat, it can be considered that an inaccuracy to the location of the top doesn't affect things too greatly.

While HR contribution was found to differ between different configurations tested in the model, it did however do this to quite a small degree for COP-based pricing. Noticeably more so for Joule-based. While the approach of establishing system configurations through the methods described here brings with it innate inaccuracy, it was still seen as the most accurate way of

Thus, the larger effect of an inaccurate cost function that the author would like to point out, is that the CAPEX of configurations found by the capacity allocation algorithm will in reality diverge from the constant CAPEX they are supposed to represent. The method is however seen as suitable for its main purpose here: Establishing realistic system configurations to check HR contribution for.

As a last note: The cost functions are to represent the scenario of the case study: 2030+

3.4 Calculating the compression energy

The following method was used to calculate the compression energy. As mentioned, EHC will be the assumed compression technology for all cases. It operates on the principle of isothermal compression.

Deriving the formula for compression energy

The theoretical minimum energy needed to isothermally compress hydrogen depends on the pressure before and after compression. After which, one takes the given efficiency of the compressor into account.

"Hydrogen Compression Technology" states that the theoretical minimum isothermal compression energy from 20 bar to 350 bar is 1.05 kWh/kg, and from 20 bar to 700 bar is 1.36 kWh/kg. The source however does not state the formula used, so it will be derived below, starting with the work expression by isothermal compression of an ideal gas in the case of an infinitesimal change in volume or pressure. Which is as follows [104, p. 167]:

$$W = PdV = VdP \tag{3-3}$$

The expression for $V(P)$ can be found by ideal gas law and substituted into the equation above.

$$V = \frac{nRT}{P} \tag{3-4}$$

Where R is the universal gas constant, P is pressure and T is temperature, and n is the number of moles (in this case for 1 kg of H_2, which is what we're trying to find the compression energy for). To avoid confusion, the product nR is "just the gas constant" and may be what is referred to as R elsewhere. The above expression uses n = 496 moles/kg for H_2, and R is the "universal gas constant", the product of which is the "gas constant" of H_2.

However, ideal gas law does not account for intermolecular forces, which makes it inaccurate, more so at the higher pressures. The concept of a compressibility factor can account for the discrepancy in volume between an ideal gas and an actual one [104, p. 138]. The modified expression for V becomes:

$$V = \mathrm{Z}\frac{nRT}{P} \tag{3-5}$$

Where Z varies by pressure and is given by the plot in Figure 3-9 below. In order to integrate VdP, $Z(P)$ is in this instance approximated by the following.

$$Z = 1 + \frac{0.42}{700}P \tag{3-6}$$

Which is a linear approximation for the values given for 300K (near ambient temperature, 27°C). This was done opportunistically as its Z-value changes roughly linearly with pressure. However, for the more accurate results, Z should be approximated with a better curve fitting, or the integration should be performed using an interpolation over collected data points for Z.

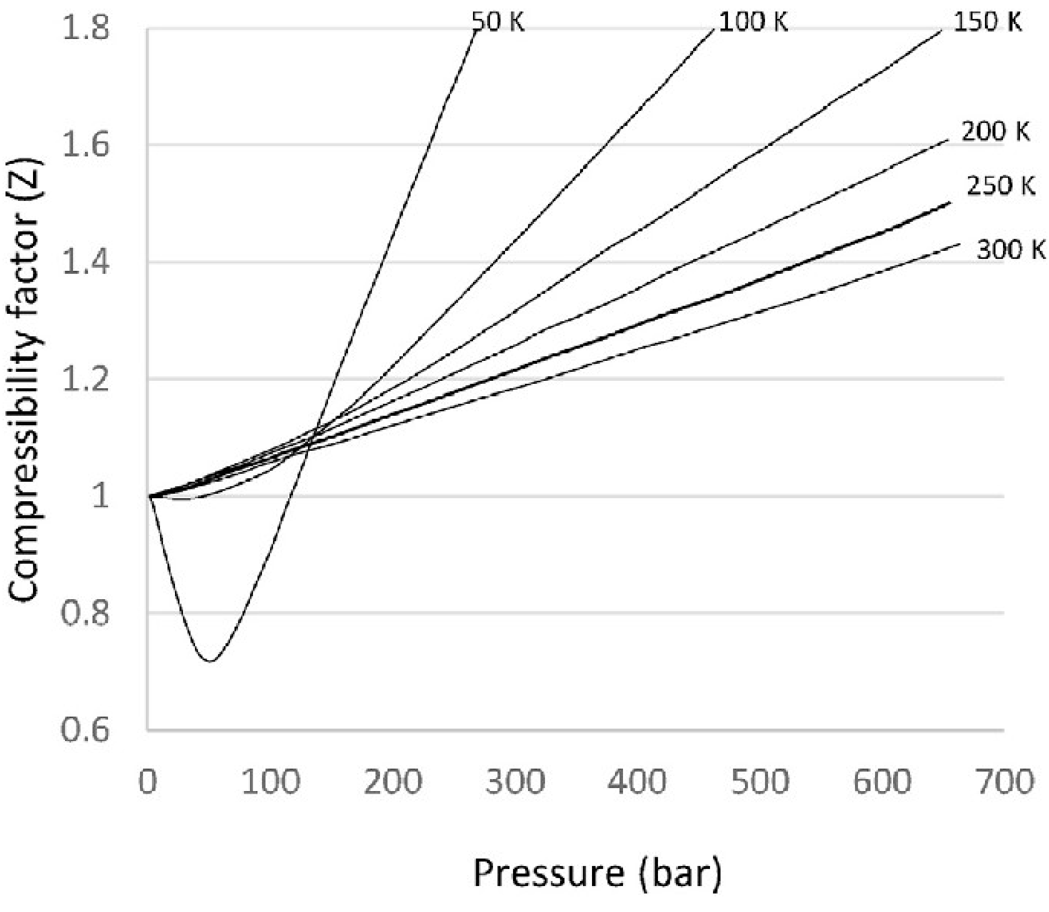


Figure 3-9: Compressibility factor for H_2. Image Credit: Elberry et. al. [108, p. 3]

The expression for the work becomes

$$W = \int_{P_1}^{P_2} V(P)\,dP = \int_{P_1}^{P_2} \mathrm{Z}\frac{nRT}{P}dP = \int_{P_1}^{P_2} \left(1 + \frac{0.42}{700}P\right)\frac{nRT}{P}dP \tag{3-7}$$

Solving the integral yields:

$$W = nRT\left(\ln\frac{P_2}{P_1} + \frac{0.42}{700}P_2 - \frac{0.42}{700}P_1\right) \quad (3\text{-}8)$$

Noting, that the work needed per ideal gas law scales linearly with temperature, whereas the coefficient in the Z function goes down slightly with it. In the above function, the same approximated function for Z is always incorporated. However, seeing how close for example the 250K and 350K lines are to each other in Figure 3-9 it is considered a good approximation.

Per the time of writing, a more expansive plot or function for Z values depending on temperature is not found. Extrapolating where the line for 350 Kelvin would be in Figure 3-9 could be argued to yield about $Z = 1 + (0.38/700)P$, which is more aligned with the operating temperatures seen for AEL and PEMEL (350 K = 77°C).

Inaccuracies regarding the rough assumption of Z for other temperatures than 300 K, will occur with this method. But, experimenting with Z values between $1 + (0.3/700)P$ and $1 + (0.6/700)P$ (based on the 200 K line and assumed position of the 400 K line) shows that this inaccuracy in any case accounts for a roughly 2.5% difference, over a span as large as 200 K.

However, if temperatures much higher were to be considered, from high temperature electrolysis (even with HR/cooling implemented on gas streams), a more accurate source than above for its Z, would have to be acquired.

Accounting for η_{EHC}

Using $n = 496$ mol (for 1kg of H_2), $R = 8.314$ J/(mol K) (the universal gas constant) and using 300K as the temperature (26.9°C), yields the same numbers stated in "Hydrogen Compression Technology" for both pressure increases. 1.05 and 1.36 kWh/kg for compression between 20 to 350 and 700 bar respectively. Values obtained by the above formula were both 0.01 lower than those given by the source. They did not state how they calculated theirs, but the formula derived above seem to give equivalent results. The small disparity could come from the linear approximation of the compressibility factor, or other input being slightly different. Said numbers being the theoretical compression energy, before taking η_{EHC} into account. Doing that, the work function becomes as follows:

$$W_{compression} = \frac{nRT}{\eta_F}\left(\ln\frac{P_2}{P_1} + \frac{0.42}{700}P_2 - \frac{0.42}{700}P_1\right)\left(\frac{1}{3.6 * 10^6}\right) \quad (3\text{-}9)$$

A paper about recent progress and challenges in EHCs, claim that their efficiency "tends to be higher than 60%" [81]. However, it is not as straightforward as just assuming this figure for any EHC. A presentation by HyET ("Hydrogen Efficiency Technologies", a manufacturer of EHCs) gave efficiency figures for EHC compression, in terms of the compression energy needed per kg of H_2 [109]. As seen in Figure 3-10 below.

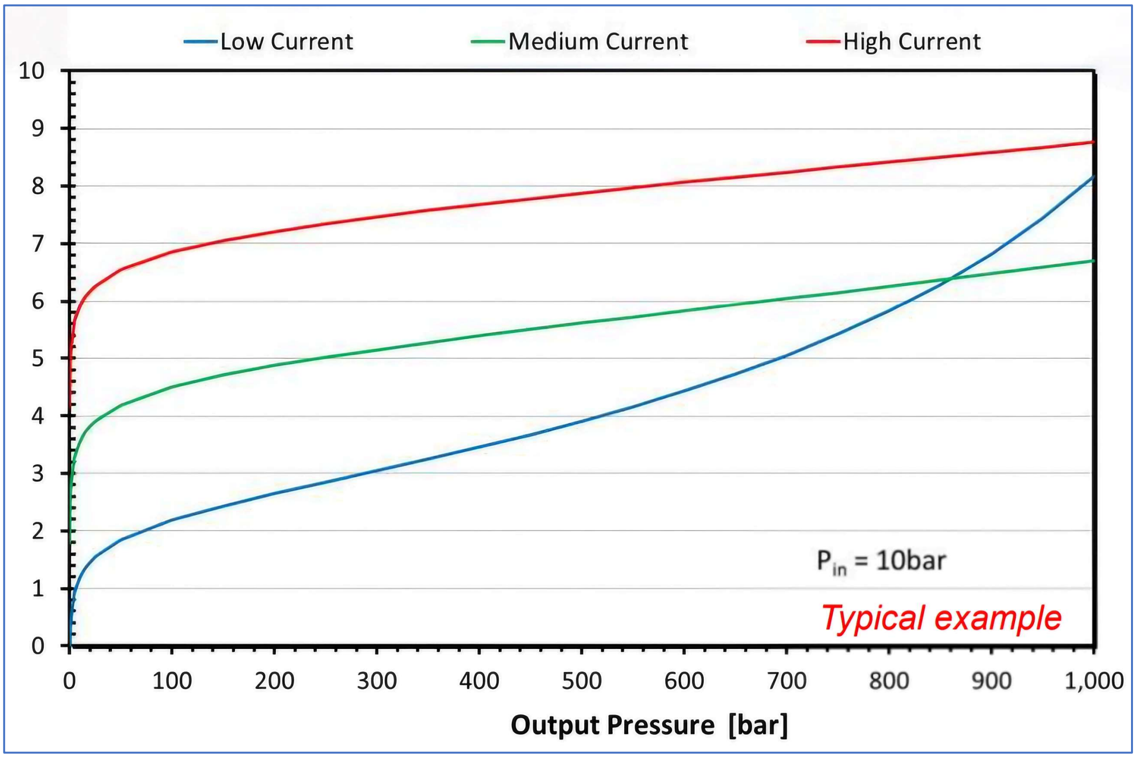


Figure 3-10: Compression energy from 10 to P bar depending on current density. Image Credit: HyET [109].

Firstly, it can be seen that increasing current density, leads to lower efficiency (higher energy consumption). This can be thought to have the same background as it does for PEMELs. Higher current density leads to higher cell voltage, which reduces efficiency.

This also speaks to the characteristic that a more efficient EHC will be innately more costly, because it needs to run at a lower current density to achieve the high efficiency and thus needs a larger PEM (its chemically active surface area), which as discussed earlier, has a majority of its associated cost coming from material costs, thus scaling quite steeply with the PEM size.

More so, further losses are associated with the "impact of H_2 cross-over" [109]. Leak currents, and permeability coefficient, both being functions of the cathode pressure. Thus, both back-pressure and current density affect η_{EHC}.

The permeation is calculated as per the given permeability coefficient graph on slide 21 of HyET, to be negligible. Leak currents seem to be more substantial. However, the data necessary to perform calculations with these was not obtainable (or, HyET has not responded with inquires of exact data or their methods of calculating the plot in Figure 3-10 at the time of writing this).

As mentioned, the compressor efficiency and cost, will be combined with that of the electrolyser for this thesis, as their throughput must be roughly the same. Thus, a figure is needed when it comes to the cost of EHC, and the efficiency of EHC. However, detailed specifications from manufacturers or off the shelf hardware were not found. Simplifications will have to be made for this thesis.

Considering that (especially for the energy storage and CHP case) round-trip efficiency is very important (the reason for, will be explained in section 2.10), a low current density EHC will likely be employed.

For reference the effect that the compression energy has on the "energy throughput efficiency" of the electrolyser is as follows:

$$\eta_{ELY.w.comp} = \frac{E_{H2,LHV}}{\frac{E_{H2,LHV}}{\eta_{ELY.pre.comp}} + W_{compression}} \tag{3-10}$$

For an arbitrary (but realistic) electrolysis efficiency of 0.7, this would amount to reducing it from 0.7 to 0.67 for the lower end compression efficiency of 2kWh/kg H_2. For the upper end of 8 kWh/kg H_2, the total electrolyser throughput efficiency would be down from 0.7 to 0.59. Later results show that the latter efficiency reduction is extremely detrimental to system performance, and thus the assumed decision is to minimize the compression energy as much as possible, despite any cost difference it would incur for the EHC CAPEX. The blue line will thus be used as the reference in this thesis.

This is however for an input pressure of just 10 bar. Which is less than the output pressure of many electrolysers. (PEMEL for example operating in 50 to 80 bar.) What will be done, is to use a simplified method to adjust for this. The process will go as follows:

A compression energy will be chosen for the post-compression pressure from Figure 3-10. This will then be linearly scaled by the ratio between the theoretical energy for the pressures we want to find the energy for, and those that the plot gives (always being from a starting pressure of just 10 bar). This is a simplified, rough estimate, based on the efficiency of the EHC staying constant with varying pre-compression pressures (e.g., 50 bar instead of 10 bar). Considering the pressure difference over the membrane is smaller, the efficiency is likely in actuality better, and thus this is considered a conservative estimate. As an example, the theoretical energy for 50 to 250 bar is half that of 10 to 250 bar, and in such a case, a factor of 0.5 will be used on the energy given in the chart.

4 Case 1 – Combined Energy Storage and CHP system

This chapter is split in four parts:

- The "Introduction", where the structure and goals for the case study are summarized. Repeating the circumstances and background and describing what the case study tries to do in short.
- The "setup and dimensioning" where said background is consolidated to establish specifics of the envisioned case. This part will include the design choices for the H_2 system and the description of that, as well as arguments for decisions taken and any case-related assumptions. (This is partly deferred to Appendix B)
- The "Optimization model", where the mathematical formulation of the linear program is presented and discussed.
- The "Results and discussion", where the results from the model are presented, and then discussed.

4.1 Introduction

As introduced, this first case-study will look at an envisioned H_2 energy storage and CHP-plant in London. It is envisioned to be connected to a district heating network.

Background for the case is found both in the Introduction and Theory chapters. Section 2.1.1 discussed the UK energy market and its future prospects. Section 2.10 discussed the value of recovered heat in the case of heat costs being heat-pump based.

The case study was also to investigate different states of H_2 technologies. Considerable improvements are expected towards 2030 and beyond. However, degradation of efficiency for electrolysers and fuel cells is significant. Thus, system configurations with more conservative efficiencies will also be investigated/presented. This will be done by including results for a 2023 state of H_2 technology too. In this way, the conservative performance of a 2023 system will be included for reference, which is also intended to give an idea of how a degraded 2030+ system would perform.

The degradation between 2030 electrochemical efficiencies and those found for 2030, represent a 21% reduction for the fuel cell and a 12% reduction for the H_2 production. It cannot be answered within the scope of this thesis, exactly what degradation should be allowed in the context of this case study. But it is found sensible to allow the fuel cell to degrade more, as its heat recovery output is innately more valuable from being sold at times of peak energy pricing, whereas the electrolyser HR is not.

All in all, there are quite a multitude of scenarios that are to be investigated. There are two system specifications. These will be investigated in three pricing years. And all of these cases will have results for both heat-pump/COP-based heat pricing and resistive heating.

Thus, the result chapter will be split up. The first results chapter will be for resistive based heating, also referred to as Joule-based heat pricing. Whereas the second one will show what happens if heating was to be based on the COP-values of heat pumps. Both in terms of overall performance, and the contribution of heat recovery towards that performance.

But first, the next section will present the setup of the envisioned case, as well as the dimensioning of energy storage system.

4.2 Case study setup

4.2.1 Case scenario

Energy Storage System - Case Concept Repetition/Summary

The case study is about an envisioned storage system, around the time of 2030+, or once economies of scale have become established around H_2 components to the degree that referenced sources state in their cost estimations.

The case is to take place in London. Natural gas (or fossil fuel based) heating is phased out, and DHNs are much more widely used than today. (As per the background presented in the introduction and theory chapters.)

The HESS, or hydrogen energy storage and CHP system, is to provide electricity and heat to a city neighbourhood or district, where the energy flow is as shown in Figure 4-1 below.

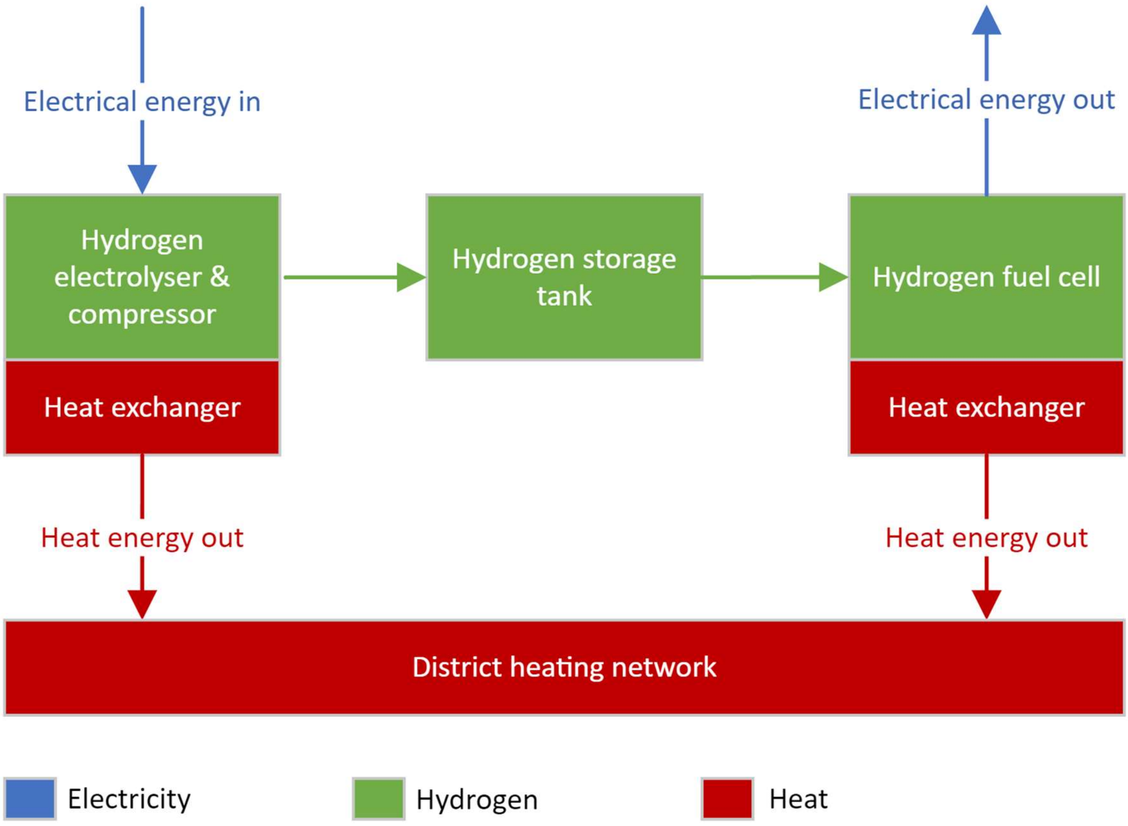


Figure 4-1: Hydrogen energy storage and CHP. (Simplified/basic layout)

And the DHN layout in which it operates, is described by Figure 4-2 below.

Where the heat load is simplified in to a total DHN distribution network load, as follows

$$L_{heat} = \sum_{i=1}^{n} L_{heat.i} \tag{4-1}$$

This value is given as data. It is the heat demand of the houses.

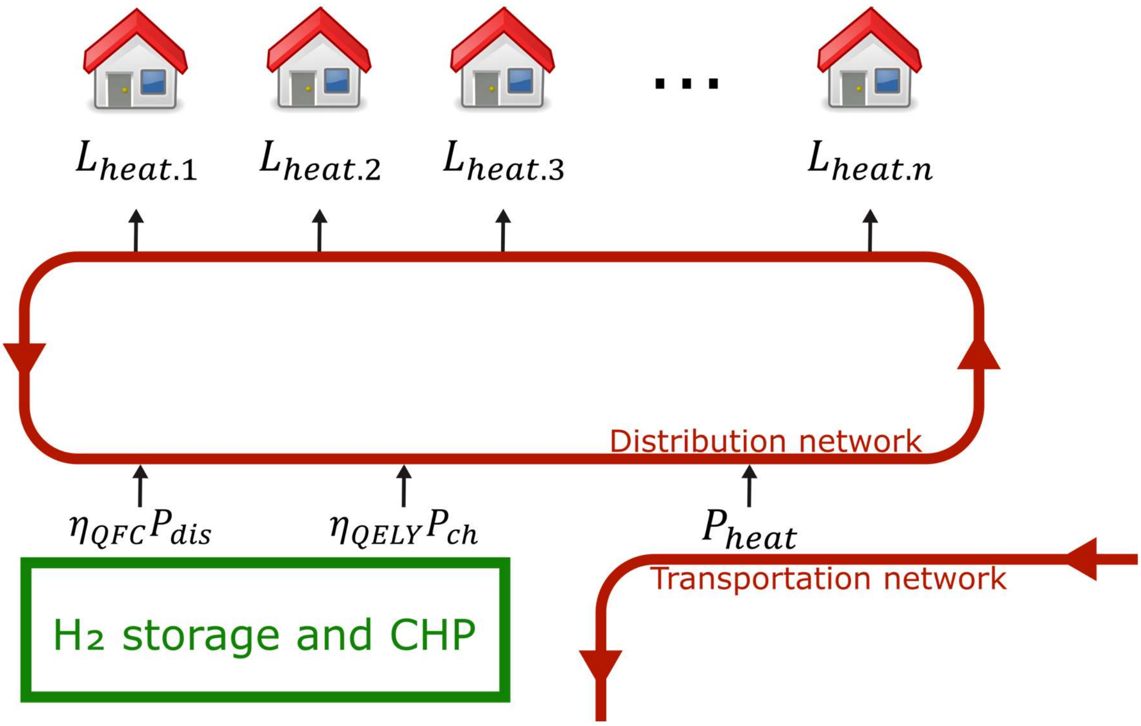


Figure 4-2: DHN layout for case 1. Credit for "House icon" SVG-file: OpenClipart [13].

Here, P_{ch} and P_{dis} are the electrolyser and fuel cell input powers (in the considered time-period, usually being an hour or half-hour). P_{heat} is defined as the amount of heat that is bought from "whatever heat source is available". In this case, it is the heat exchanger with the city DHN transportation network. But it could also be a water-source heat pump for example.

What is to be modelled, is the *distribution network* loop. Although, the diagram in Figure 4-2 above, only shows the heat components. The model also considers the electricity demand of the houses connected to the DHN (distribution loop).

The performance of the system is measured in "money saved". This is defined as:

How much less money is spent on energy for the district as a whole,
compared to not having the system there.

And the district, is here defined as the group of houses connected to the distribution network.

Each house is however not modelled. Since the focus here is on the H_2 system, it was chosen to simplify the DHN part by grouping all loads and considering the district as a unit.

The basis for the case study, starts with electricity consumption data for 25 houses, together with accompanying heat demand, and COP-data (from renewables.ninja and the when2heat dataset). The estimated inputs used with renewables.ninja for the generation of heat-demand data ended up at 80% of the total energy-need for the houses from the first try. This matches exactly the average heat-share of demand for domestic energy use in the UK [12].

The size of the district will however not be 25 houses, as it turns out it will not be sensible to implement an H_2 system with components that are suitably small for that DHN-size. This is due to the cost of H_2-related components being very high per capacity for smaller units. As seen by the cost-functions in section 3.3. The size of the DHN that is suitable for the system will be considered at the end of this "Case study setup" section.

First the choice of component type, and their efficiency figures will be established. And then the system CAPEX is to be established.

In this case, the system CAPEX will be established as the base dimensioning criteria. A scenario that fits a sensible systems size will be found. Instead of the other way around.

The system CAPEX will be set to a level that is found no not cause unreasonable prices according to the cost functions (which have large costs per capacity for small systems). And then the DHN-size onto which the system will be attached, will be chosen. This is after all a study to find the "potential" of H_2 with HR in this scenario, and it is thus found sensible to create a scenario where HR is not limited by DHN size, and where the system isn't severely limited by an unsensible cost per capacity for some components.

4.2.2 Electrolysis for case 1

Electrolysis technology choice

For case study 1, an electrolyser that will cycle on and off once or more daily, and one that can fit into the location of a DHN hub without incurring extra large infrastructure costs is preferred.

A PEM electrolyser is seen as the optimal/likely technology for use in 2030+. Reasons include the relatively compact size compared to an alkaline one, which both makes the application of heat recovery more manageable, as well as the space requirement and installation process. Sources also quote simpler maintenance and three times faster startup times [10, p. 2].

The latter will be advantageous with regards to thermal losses associated with recurring (daily or more frequent) start-up/shutdown of production. Especially considering the considerably higher thermal inertia/capacity of an alkaline unit as well.

SOEL could be an interesting option due to the possibility of delivering DHN 3.0 temperatures. However, DHN 4.0 or 5.0 is seen as more future-oriented, as well as more in line with the HR temps for fuel cells for the case 1 system. The most important reason for choosing PEMEL is however the predicted price decrease. In addition to all the other advantages, more power per CAPEX is assumed to make PEMEL the clear choice in the future, for any application where utilizing electricity price-volatility is central to the operation.

The PEM electrolyser specifications will be based on the NEL MC250 (see citation for visualizations of container and cell stack size) [110].

Electrolysis energy efficiencies

The work on establishing the full electrolysis system efficiency was quite long. Thus, the in-depth literature review and detailed calculations can be found in Appendix B.

In short: Three sources were investigated regarding HR calculations. The first was found to be flawed in the later stages of the project, upon which the other two were found and their methods adopted. Based on these, the heat loss from the electrolysis stack was considered near negligible even before insulation is applied. The stack is very power-dense while having just an 80°C operating temperature. Thus, virtually 100% of the energy heat output to the stack was counted as recovered. The BOP input (being a loss) was established on top of this, and compression losses were calculated and added.

The "system power" for electrolysis is then defined as:

$$P_{charge} = P_{BOP} + P_{compression} + P_{stack} \tag{4-2}$$

Out of P_{char} the energy output splits in three. H_2, heat by-product and BOP losses. Energy flows are visualized in Figure 4-4 below for the conservative system, and Figure 4-5 for the optimistic system.

Electrolysis spec. → Outputs ↓	Conservative	Optimistic
Electrochemical (HHV)	65.2%	73.7%
Heat	22.0%	13.0%
Total (energy-efficiency)	87.2%	86.7%

Figure 4-3: Electrolysis efficiencies

The used compression energy might be somewhat optimistic. Sources were reviewed to find and validate electrolyser efficiency as well as assumptions on BOP-power. The compression energy was estimated as per the method from section 3.4. It was assumed a medium current density for the conservative case, and a low current density for the optimistic case. Today's EHC efficiencies align more with high current densities, however, it is stated that: "Current developments will lead to significantly lower energy consumption rates" [111].

It must however be said that this is somewhat of a departure from statements that the conservative system should represent 2023 efficiencies. This was a choice based on a low current EHC being installed in the optimistic system and then degrading to a medium current density. It was seen as more relevant for the conservative system to represent a degraded version of the 2030+ one, than to be more accurate in terms of what one can get off the shelf in 2023. It was seen as likely that the EHC wouldn't be allowed to degrade to high current densities in that context.

Possibly counter-intuitively, the total energy efficiency is higher for the conservative system. This is because the conservative system has a relatively lower share of its full power input to stack + BOP, due to its higher compression energy. While also having a lot higher HR-share of its compression power. When the small heat losses from the stack are considered negligible as done here, the system with the higher compression power thus has a higher RTE (round-trip efficiency). See Appendix B for calculations of the above/below figures, as well as in-depth literature review with sources.

Notably, sources often quote ~94-95% efficiency for electrolysers with heat recovery [10], [112]. But the values found for the system above include compression energy, and also BOP-power. "A Comprehensive Review on PEM Water Electrolysis" states figures that indicate 7% of input energy going to BOP as a lower end estimate, and 25% as a higher end estimate [113, p. 4904]. Thus, the 88% of input energy to stack (12% to BOP) found for the electrolysis system (pre-compression) in this thesis is seen as reasonable

Conservative/2023+ electrolysis efficiencies

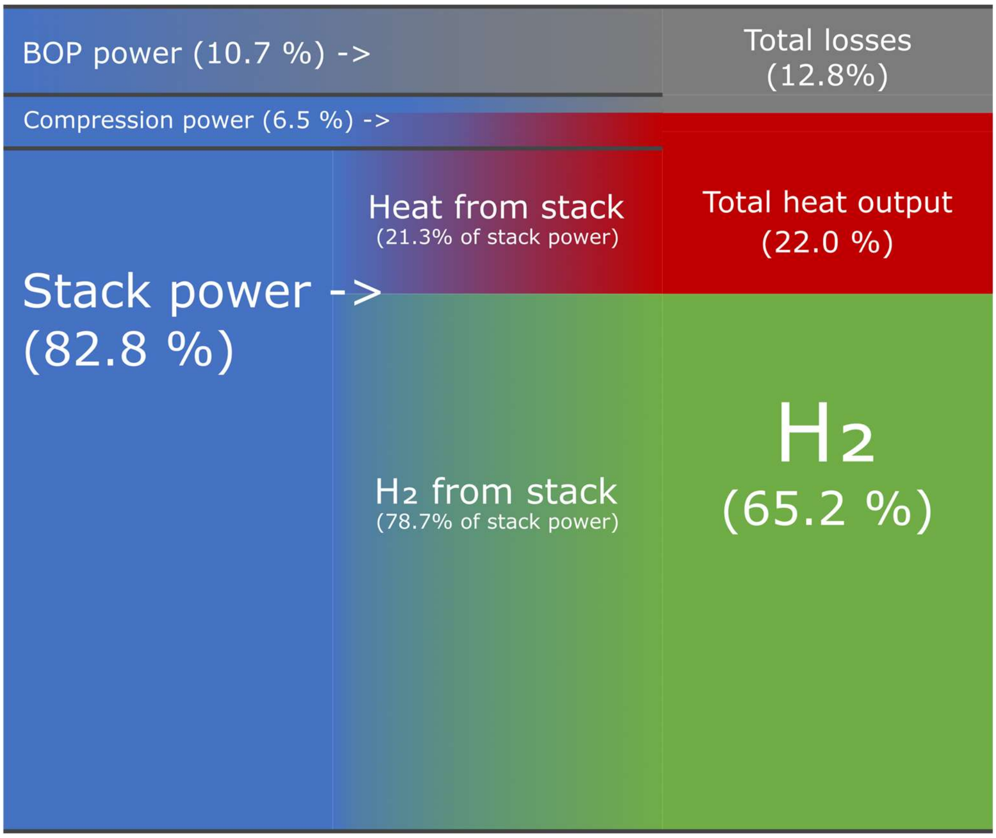


Figure 4-4: Electrolysis Energy Input to Output

Optimistic/2030+ electrolysis efficiencies

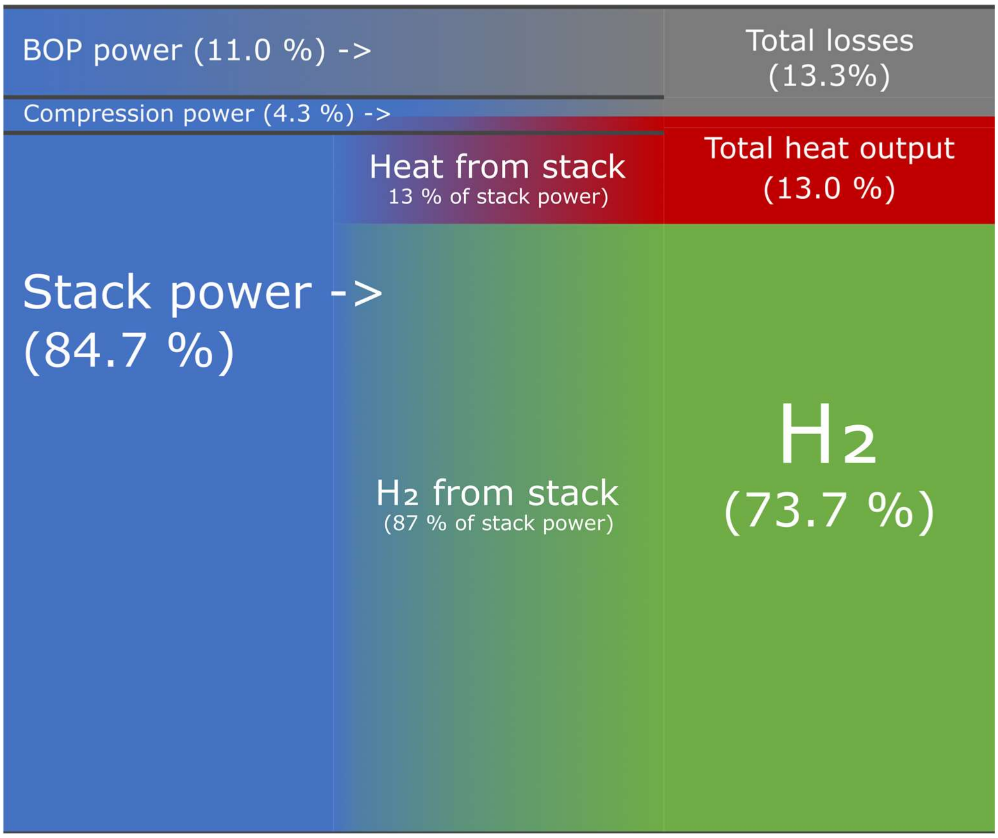


Figure 4-5: 2030+/Optimistic Electrolyser Efficiencies

4.2.3 Storage for case 1

Storage units/technology

The unit type to be used, comes down to the long-term costs, and environmental concerns. The cycle life would be weighed against the cost of acquisition. However, no reliable sources on a good cost of acquisition of a full storage system (with piping, auxiliary structural components etc.).

Whether type I or type IV will be used is also an environmental concern. Taking into account their environmental impact vs. their cycle life. A conclusion on what is the best option is a large body of work deemed outside the scope here, and it is assumed that MEGC (multiple element gas container) units with type IV composite tanks will likely be used. Those will be the basis for the cost function.

4.2.4 Fuel cell for case 1

Technology choice

Due to the high TRL, better start/stop stability and an operating temperature that matches the chosen electrolyser, PEMFC is chosen as the fuel cell technology.

Conservative/2023 system specifications

Specifications for large fuel cell units including heat recovery was harder to come by than for electrolysers. Either small units or "outdated" efficiencies were referred to when this was researched.

For the conservative system specification, the basis for the efficiency assumptions will be a smaller unit from Panasonic in 2021 [11]. It is assumed that this device is conservative estimate for electrical and heat-recovery efficiencies, representing both 2023 state of tech while being a good representative of a degraded 2030+ system.

It is claimed (as of 2021) to achieve the industry's best commercially available electrical efficiency as of 2021, at 56%. It has a built-in heat exchanger that delivers output water at a temperature of 60°C, compromising 39% of the input energy. The overall efficiency is thus 95% [11].

However, all of the above were figures given for LHV, and must thus be adjusted down by a factor of 33.33/39.39 = 0.846 for the context of this case. Where HHV is worked with.

The HHV-based efficiencies of the full fuel cell system for the conservative scenario, is estimated:

$$\eta_{FC.2023} = 47.4\% \tag{4-3}$$

$$\eta_{QFC.2023} = 33\% \tag{4-4}$$

Making fuel cell total energy efficiency compared to HHV about 80 %.

Optimistic/2030+ system specifications

As for future expected efficiency figures, sources claim quite varying figures. "PEM Fuel cell and electrolysis cell technologies and hydrogen infrastructure development – a review" states that by 2030, efficiencies of 68% is expected by 2030, and "ultimately" 72% [114]. 70% will be used for the 2030+ scenario (beginning of life) efficiency.

This is interpreted to be the LHV-based efficiency (this seems to be the convention for stating fuel cell efficiency figures). The adjusted electrical efficiency is:

$$\eta_{FC.2030} = 57.5\% \quad (4\text{-}5)$$

The heat loss is assumed to remain constant, equalling 5% of the LHV input. The available HR (relative to HHV input) then becomes:

$$\eta_{QFC.2030} = 0.846(100 - 70 - 5) = 21.2\% \quad (4\text{-}6)$$

Which makes for a fuel cell total energy efficiency of about 79%.

4.2.5 DHN for case 1

DHN generation

The DHN generation is assumed to be 4th gen. This allows for the 60°C output temperature of the fuel cell to be utilised, while avoiding the very large costs of implementing a 5th gen network.

Setting up the system size and DHN size

The base size for this case in terms of data, was 25 houses. This is the number for which electricity consumption data was for. However, due to the cost curves described earlier, it would not make sense to implement a H_2 storage and CHP for such a small number of houses. The cost per capacity would either be too large, or the heat absorption of the houses would greatly limit the systems operation.

Thus, the case will be "scaled up". Sized to a level that makes sense when it comes to the cost functions. Both in terms of achieving a reasonable cost per capacity, and while being within the domains for which the cost functions are assumed to be accurate.

Arbitrarily, a CAPEX of 1.915M GBP was found to be a suitable input to the "capacity allocation algorithm". The same CAPEX as two of Tesla's Megapack 2, excluding installation costs. However, noting that this only includes the CAPEX of the electrolyser, compressor, tanks, and fuel cell in the case of the H_2 system. This CAPEX input was found to produce system capacity values that were around reasonable domains of the cost curves.

The DHN-size was in this envisioned case, sized according to the system. In a potential real application, it may have been the other way around. The important factor here, is that that the capacity for taking up the recovered heat exists, so that the potential value for HR can be found.

A DHN size of 500 domestic units was chosen to be a realistic one for the described system, in terms of negligibly limiting the utilization of recovered heat. This is also with considerable room to spare (leaving room for utilizing the city DHN connection well). For reference, it was observed that going down towards 100 houses of heat demand would not induce more than a few percents of loss in performance (money saved). 500 houses is on the upper end of what is considered a medium-sized DHN in the UK [115, p. 2].

The DHN size was adjusted in the python script by using a district sizing factor variable, dsf, which scaled all appropriate data and parameters. It is known that this might somewhat change the realism of the electricity consumption data. A group of 500 houses may tend to have a somewhat smoother curve than one of 25. But the difference is assumed to not be critical with a base sample size of 25.

The DHN efficiency is simplified as a constant, as per described in the DHN section of the theory chapter.

$$\eta_{DHN} = 0.90 \tag{4-7}$$

4.2.6 System efficiencies summary

Table 4-1 below presents a range of found efficiencies or energy output shares. Figure 4-6 and Figure 4-7 below show the full energy flows for the ~2023 and 2030+ system specifications visually in a more intuitive format.

System Specifications	2023 specification	2030 specifications
Electrolyser efficiency pre-compression	0.697	0.77
Electrolyser efficiency incl. compression	**0.652**	**0.737**
Electrolyser heat recovery	**0.22**	**0.13**
Electrolyser and compression full efficiency	0.872	0.868
Fuel cell electrical efficiency	0.474	0.575
Fuel cell heat recovery	**0.33**	**0.212**
Fuel cell total efficiency	**0.79**	**0.79**
DHN efficiency	0.90	0.90
System round-trip electrical efficiency	**0.31**	**0.42**
System round-trip HR output (pre DHN)	0.55	0.28
System round-trip HR output (post DHN)	0.49	0.25
System total RTE pre DHN-loss	0.74	0.71
System total RTE with DHN-loss	0.70	0.68

Table 4-1: System specification versions, as found/derived in section 2.5, 2.6, 2.8 and 2.7.

Notably, the overall efficiencies including HR are quite similar. Actually, the total efficiency of the optimistic system is lower. This is largely because more of its electrolyser energy output goes to the fuel cell, which then has relatively higher losses for to BOP and non-recovered heat. Thus, the total energy-efficiency is actually lower than the conservative system. However, for the application at hand, it is a far more important metric to have a higher share of the energy at the fuel cell export which is at times of high pricing. Furthermore, electrical output is also innately more important when a COP based pricing is introduced. Thus, the optimistic system will perform better by a large margin. This is shown by r_P values for the system in Figure 2-25.

The electrical efficiency is about 1.36 times higher on the optimistic system. Whereas its fuel cell heat output has about a 0.64 ratio to the conservative one, being the most important factor in how much HR will contribute to its success.

Following is the energy flows relative to the energy input for each system specification.

As presented in chapter 2.10, a more “relevant” performance indicator than energy efficiencies does exist for this type of system. The pricing ratio performance factor: r_P. Plots of this for each system can be found on page 51. Meanwhile, the figures below visualize well where the input-energy ends up.

Conservative system energy flow

(All numbers relative to 100% electrical energy in)

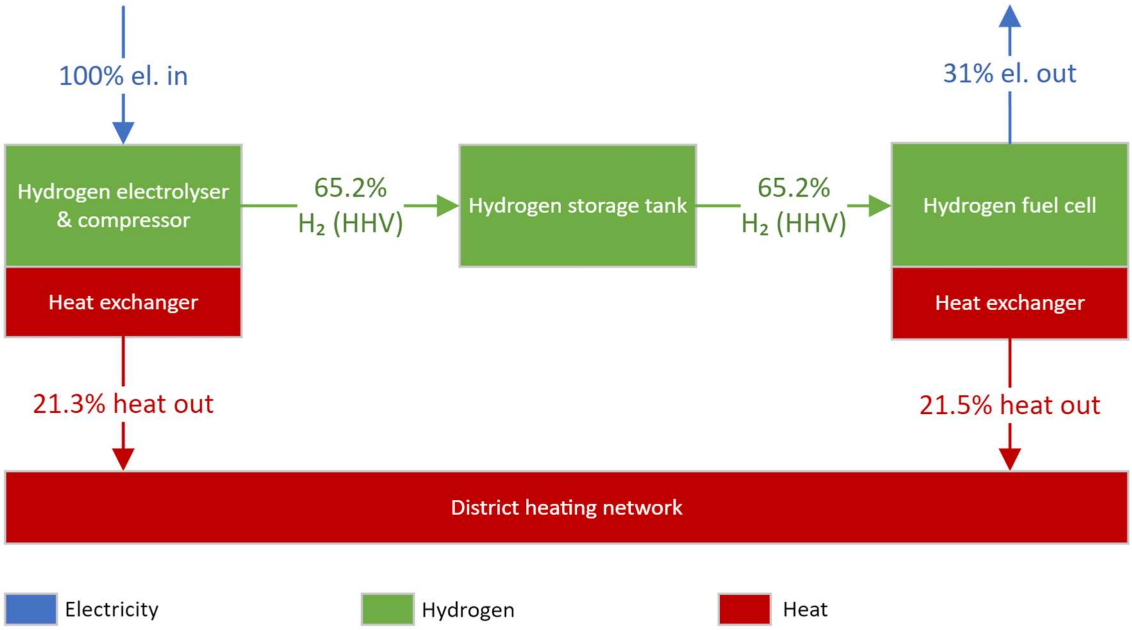


Figure 4-6: Conservative system energy flow

Optimistic system energy flow

(All numbers relative to 100% electricity in)

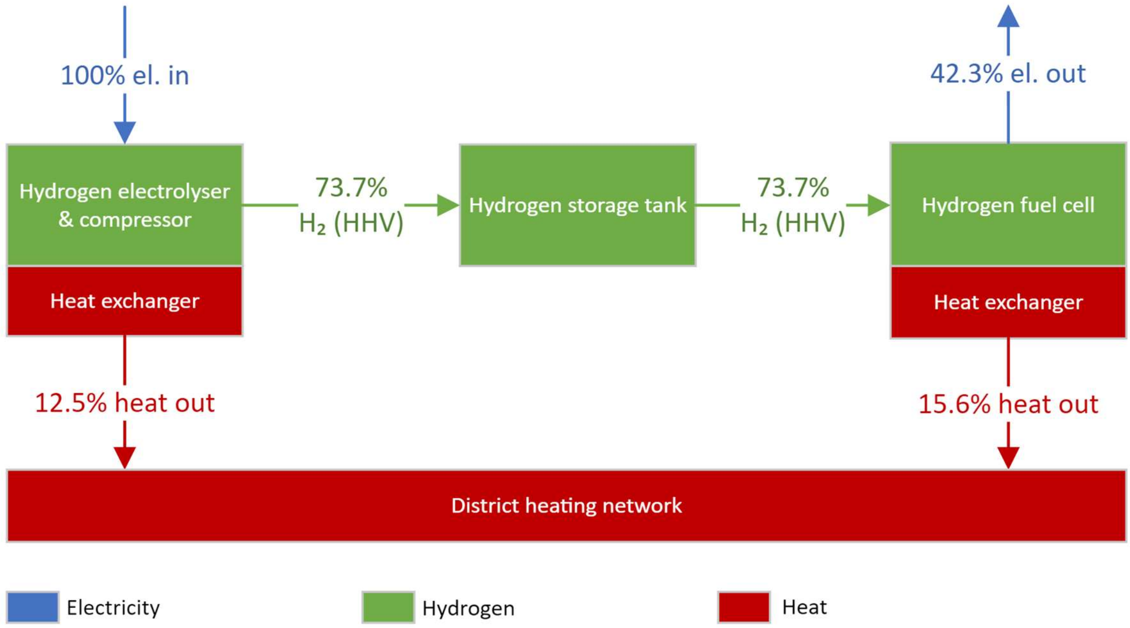


Figure 4-7: Optimistic system energy flow

4.2.7 Cost functions for case 1

To run the case, cost functions were needed for the main components, or rather, the system capacities. The following is those cost estimation functions.

Electrolyser CAPEX estimation

From the EHC chapter in the Theory-chapter, we had that the electrolyser + EHC cost was estimated with:

$$C_{ELY}(1 + 0.32\eta_{ELY}) \tag{4-8}$$

Where C_{ELY} is the cost per capacity, as a function of system size. Substituting in Reksten et al.'s equation for C_{ELY} and multiplying with the system size, we have the system cost:

$$K_{electrolyser} = \left(\left(585.85 + \frac{9458.2}{x}x^{0.622}\right)\left(\frac{2030}{2020}\right)^{-158.9}\right)(1 + 0.32\eta_{ELY}) \tag{4-9}$$

Where $K_{electrolyser}$ is the cost of the electrolyser, x is the electrolyser system input power in kW, and η_{ELY} is the electrochemical efficiency.

Tank CAPEX

In depth literature review, sources, and discussion on this is found in Appendix B. In short, sources predict tanks to be very cheap in the future. Furthermore, MEGC (multiple element gas containers) often consist of something like 50-100 elements, and said elements are thought to be mass produced at a large scale. Thus, the cost of storage is approximated as being linear:

$$K_{tanks} = C_{tanks}y = 11.2y \tag{4-10}$$

Where K_{tanks} is the cost, and y is the storage capacity in kWh.

Fuel Cell CAPEX

Again: In depth discussion with sources are found in Appendix B. The cost function for fuel cells is a rougher estimation than the one done by Reksten et al. for electrolysers. A source having 3 data-points for different system sizes around 2030 was found. A power trend-line fit was performed, and the shape of the function was found to be logical.

The fuel cell cost is given from the C_{FC} per output power. However, the model treats the fuel-cell power as the HHV input. Thus, the function for K_{FC} adjusts for this, and becomes:

$$K_{FC} = (0.846\eta_{FC}z)C_{FC} = (\eta_{FC}z)4925.6(\eta_{FC}z)^{-0.201} = 4167.8(\eta_{FC}z)^{0.799} \tag{4-11}$$

Where η_{FC} is the HHV electrical efficiency, C_{FC} is the cost per capacity function, and z is the HHV input power (in kW H_2-equivalent) to the fuel cell.

Capacity CAPEX summary

Figure 4-8 below shows the cost functions for electrolysers and fuel cells respectively. For fuel cells it seems to go down a bit more steeply than for electrolysers, which is sensible regarding fuel-cell market trends discussed in Appendix B. It doesn't align particularly well with the three data-points, however looking at Reksten et al.'s extensive electrolyser data it is also seen there that points differ considerably from the trendline. As discussed elsewhere, the functions are in any way a rough estimation for allowing the algorithm to establish a "realistic" system capacity configuration. Notably, the cost function for the electrolyser is for the cost per system input power, whereas the for the fuel cell it is cost per electrical output.

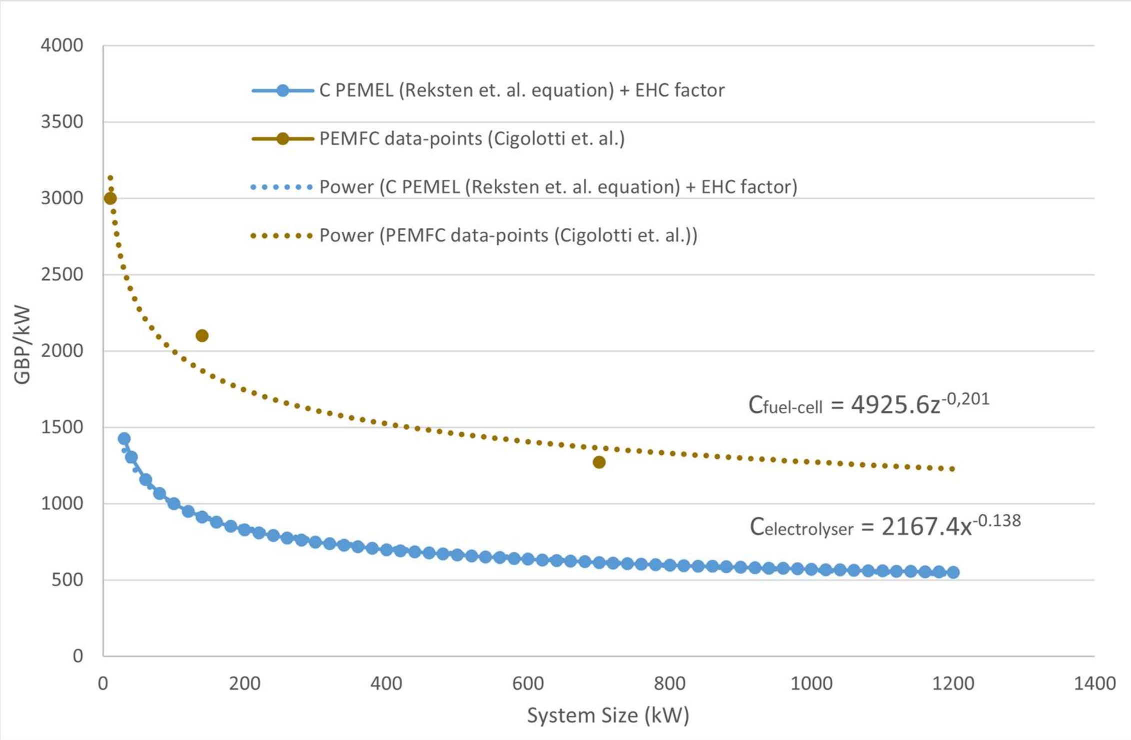


Figure 4-8: Cost functions for PEMEL and PEMFC

4.3 Optimization model

Note: A superscript i denotes a variable for which there exists one instance per time-period (half-hour) in the optimization model.

4.3.1 Model nomenclature table:

Variable	Entity/Explanation/Comment	Type	Domain
$P^i_{electrical}$	Average power imported from the grid to direct use for electrical appliances	Unknown	Reals
P^i_{heat}	Average power imported from the grid to direct usage for heating specifically	Unknown	Non-negative Reals
S^i	Storage state of charge	Unknown	Non-Negative Reals
P^i_{charge}	Average power imported from the grid used on the electrolyser	Unknown	Non-Negative Reals
$P^i_{discharge}$	Average brake power from the fuel cell (power delivered including all losses)	Unknown	Non-Negative Reals
$L^i_{electrical}$	Electricity load, excluding heating	Data	Non-Negative Reals
L^i_{heat}	Average net heat demand. (Heat to be delivered)	Data	Non-Negative Reals
C^i_{elec}	Average cost of energy per kWh	Data	Non-Negative Reals
η^i_{COP}	Average COP of the heat pump	Data	Non-Negative Reals
η^i_{DHN}	Efficiency of the DHN	Constant	Non-Negative Reals
η^i_{ELY}	Electrolyser electrochemical efficiency	Constant	Non-negative Reals

$\boldsymbol{\eta^i_{FC}}$	Fuel cell electrical efficiency	Constant	Non-negative Reals
$\boldsymbol{\eta_{QELY}}$	Fraction of energy charged that goes to heat	Constant	Non-Negative Reals
$\boldsymbol{\eta_{QFC}}$	Fraction of energy discharged that goes to heat	Constant	Non-Negative Reals
$\boldsymbol{P^i_{MaxDischarge}}$	Fuel cell maximum power input	Constant	Non-Negative Reals
$\boldsymbol{P^i_{MaxCharge}}$	Electrolyser maximum power input	Constant	Non-Negative Reals
$\boldsymbol{S^0}$	State of charge at the beginning	Constant	Non-Negative Reals
$\boldsymbol{S_{min}, S_{max}}$	Minimum and maximum charge states	Constants	Non-Negative Reals

Table 4-2: Nomenclature for Linear Optimization Model

4.3.2 Model formulation:

Objective function

Minimize

$$\sum_{i=1}^{n}\left(P^i_{electrical} + P^i_{charge} + P^i_{heat}\frac{\eta_{DHN}}{(COP)}\right)C^i_{elec} \quad \forall i = 1, \dots, n \tag{4-12}$$

subject too

Electricity Demand Constraint:

$$L^i_{electrical} = P^i_{electrical} + P^i_{PV} + \eta_{discharge}P^i_{discharge} \quad \forall i = 1, \dots, n \tag{4-13}$$

Heat demand Constraint

$$L^i_{heat} \leq \eta_{DHN}\left(P^i_{heat} + \eta_{QELY}P^i_{charge} + \eta_{QFC}P^i_{discharge}\right) \quad \forall i = 1, \dots, n \tag{4-14}$$

Heat Curtailment Constraint

$$\begin{aligned}\eta_{DHN}\left(\eta_{COP}\left(P^i_{heat} + \eta_{QEL}P^i_{charge} + \eta_{QFC}P^i_{discharge}\right)\right) - L^i_{heat} \\ \leq \eta_{DHN}\left(\eta_{QELY}P^i_{charge} + \eta_{QFC}P^i_{discharge}\right) \quad \forall i = 1, \dots, n\end{aligned} \tag{4-15}$$

Discharging Max Power Constraint

$$P^i_{discharge} \leq P_{MaxDischarge} \quad \forall i = 1, \dots, n \tag{4-16}$$

Charging Max Power Rule

$$P^i_{charge} \leq P_{MaxCharge} \quad \forall i = 1, \dots, n \tag{4-17}$$

Inventory/Storage Balancing Constraints

$$S^1 = S_{start} \tag{4-18}$$

$$S^i = S^{i-1} - P^i_{discharge} + \eta_{ELY}P_{charge} \quad \forall i = 2, \dots, n \tag{4-19}$$

Non-Negativity Constraints

$$P^i_{charge} \geq 0 \quad \forall i = 1, \dots, n \tag{4-20}$$

$$P_{discharge}^{i} \geq 0 \quad \forall i = 1, \dots, n$$

$$P_{heat}^{i} \geq 0 \quad \forall i = 1, \dots, n$$

$$S^{i} \geq 0 \quad \forall i = 1, \dots, n$$

4.3.3 Explanation of the objective function and constraints

The objective function is the sum over all time-points, of all energy expenditure associated with a cost. I.e., electrical appliances, heating and charging energy for storage. This is to be minimized. Equivalent to the money saved by the system being maximised. The money saved, being the difference between having the system and having no system.

The electricity demand constraint makes sure that the electricity demand is met at all times. Notably, since $P_{electrical}$ is not constrained to be non-negative, it can represent selling energy, if photovoltaic electricity and storage discharge becomes larger than the electrical appliance demand. Using a separate non-negative variable for sold electricity was considered (and at one point done), but this approach was abandoned as it is not necessary, and makes the model solve slightly slower.

The fact that $P_{electrical}$ can be negative also means that through it, the model can virtually transfer P_{PV} to P_{charge}. The model doesn't keep track of those variables going towards charging, but selling the electrical energy for market price and buying it straight back for charging is equivalent. This is also, why the generated solar amount for this case (which allows grid charging) is actually irrelevant. The profitability of the system depends fully on the market prices. The solar data was however still kept in the model for potential comparisons of its usefulness to that of the storage system, and for a potential version of the model that didn't allow for grid charging.

The heat demand constraint ensures heat demand is met at all times. It also however allows the curtailment of heat, in order for the H_2 storage and CHP to be able to operate on its electrical efficiency alone if the solver finds this profitable.

The heat curtailment constraint is however needed, to ensure that this curtailment represents no more heat than is actually the by-product of the H_2 system. Without this, the solver would curtail infinite heat through P_{heat} in order to make money during negative electricity prices.

The charging and discharging max power constraints, limits the charging and discharging rates to that of the electrolyser and fuel cell input power.

The inventory balancing constraint makes sure that the tank level changes correctly, according to the charge-powers that were used in the previous time-period.

Lastly, the non-negativity constraints are there to make sure that there is no negative charging, discharging, heating, or storage level.

4.4 Case 1 Results

As mentioned, the results will be presented both for the scenario of COP-based heat pricing (considered a worst-case scenario for the system), as well as with Joule-based/resistive heating-based heat pricing (a best-case scenario for the system).

In this way, the contribution of heat recovery can be shown for both extremes. Results will be given for two system specifications (low end and high-end efficiencies), and for three different years of electricity prices.

The plot of electricity prices is repeated below, as they are a highly relevant context to the following results. Pointing out, that 2019 has relatively stable prices, 2022 has extreme seasonal variations, and has intermittent periods with near zero or negative pricing. Another thing to keep in mind is that it is obtainable pricing ratios holds considerable significance, not just the pricing amplitudes.

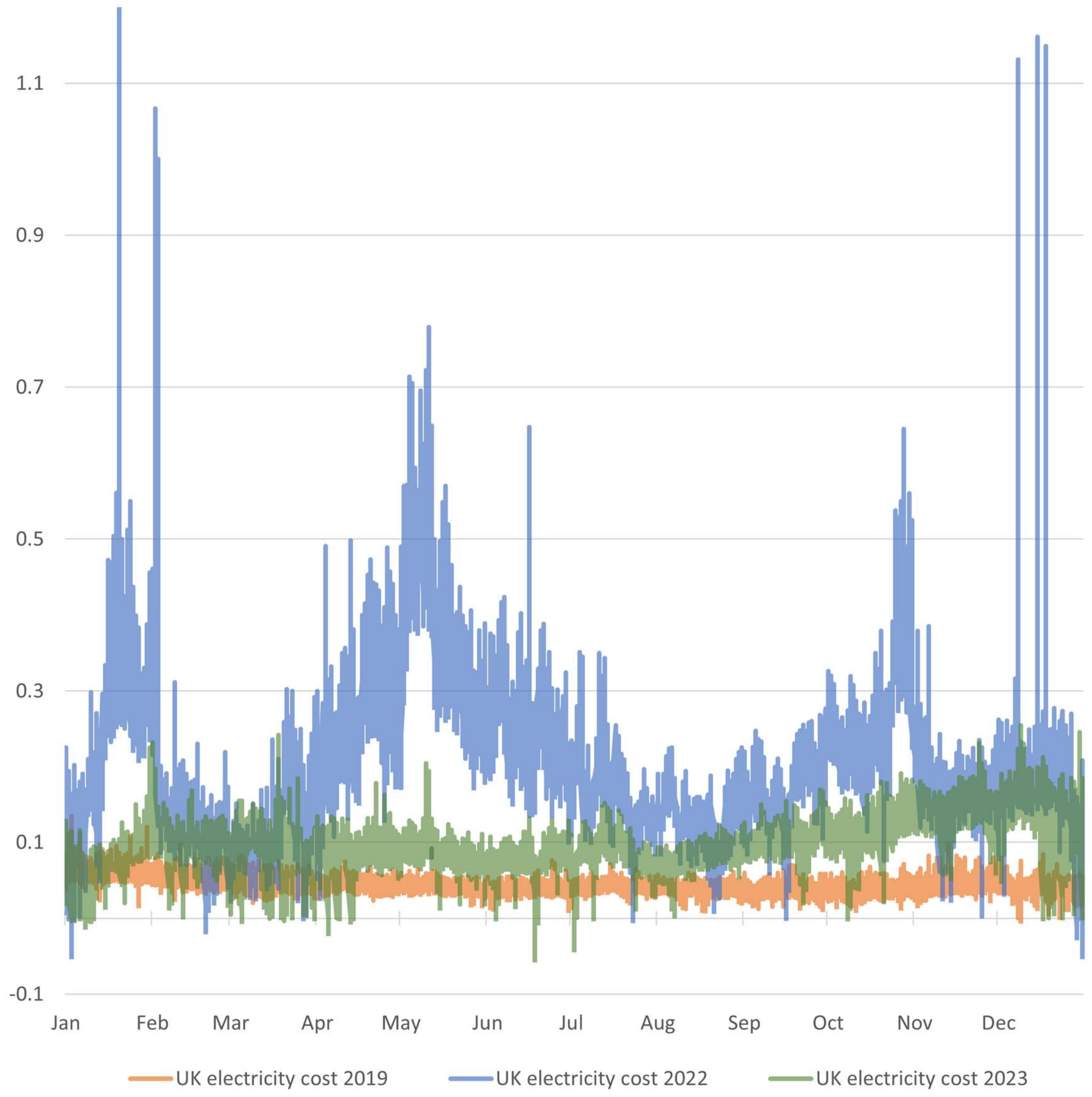


Figure 4-9: Electricity Prices for the UK in 2019, 2022 and 2023 [GBP/kWh] [28], [29]

Also keeping in mind, that the results are for a system that is connected to a district of 500 houses.

4.4.1 Results with Joule-based heat pricing

The first presented result will be the "years to recover component CAPEX". This indicates the economic feasibility of the system in the first place. See Table 4-3 for result figures. Noting, that the installation CAPEX and maintenance costs should also have been added for a truer "years to recuperate expenses", which would have made the below figures considerably larger still.

It is here evident that the system stands no chance at being feasible for the low pricing variations found in 2019. This was expected based on characteristics discussed in section 2.10.

Years to recover component CAPEX (with Joule-based heat pricing)

System spec. → Pricing year ↓	2023 system specifications	2030 system specifications
2019 CAPEX/(money saved)	211	194
2022 CAPEX/(money saved)	19	19
2023 CAPEX/(money saved)	37	36

Table 4-3: System results | Years to recover component CAPEX

The 2023 scenario also seems unfeasible. Whereas the 2022 one could potentially be plausible. It depends on economic considerations outside of the scope of this thesis. In the long run, all the tanks have to be replaced at certain intervals, whereas for the electrolyser and fuel cell, the largest long-term costs are associated with replacing the PEM components. However, details on lifetimes for these parts are not to be investigated in this thesis.

The above figures however give an idea for what they would need to be for this type of system to be feasible, in these scenarios. From here on, the 2022 and 2023 pricing scenarios will be presented further, as the 2019 scenario is deemed "in any case irrelevant". For the system to be viable in the 2022 or possibly the 2023 scenario, the cost of components would have to go down even farther than they will towards 2030 (which the cost functions here are based on).

It is concluded that very high pricing variations is needed for an H_2 system like this to stand a chance at being economically feasible. This was as expected due to matters discussed in section 2.10. However, in addition to this it is found that component costs will also need to go down considerably more than they are predicted to by 2030. The above is after all for Joule-based pricing which is probably quite a bit more optimistic than one could hope for.

Money saved by the H_2 storage and CHP system (with Joule-based heat pricing)

System spec. → Pricing year ↓	Conservative	Optimistic
2022 money saved	100059 GBP (7%)	101000 GBP (7%)
2023 money saved	51570 GBP (7%)	53585 GBP (7%)

Table 4-4: System results (with Joule-based heat pricing) | Money Made, in GBP/year.

Here, in the resistive heating case, we can observe that the results are not very different between the two system's efficiency-specifications. The percentages represent how large the profits of the system were, compared to the full energy-expenditure of the 500 houses in the DHN.

Although the capacity allocation algorithm has "paid as much" per fuel cell output as the optimistic, despite its fuel cell being less efficient. So, the fuel cell capacities of the conservative system above represents something that is slightly higher than the degraded optimistic system would be. This is how the results were chosen to be presented. 2023-efficiencies optimized, vs. 2030 efficiencies optimized, based on the cost functions.

It can be mentioned that if the system capacities of the optimistic system were run with conservative efficiencies, it would for this case degrade its performance by about 7—8% while it goes towards 2023 efficiencies.

All in all, it can be seen that the systems perform fairly similar with Joule heating, despite one having a far lower electrical efficiency. HR is able to decently make up for the η_{el} degradation.

Before moving on to the heat recovery contribution, the system configurations that were found optimal will be presented.

System configurations for each system (with Joule-based heat pricing)

System spec. → Pricing year ↓	2023 system specifications [ELY input, HHV storage, FC output]	2030 system specifications [ELY input, HHV storage, FC output]
2022	823 kW | 61.2 MWh | 423 kW	866 kW | 54.7 MWh | 454 kW
2023	1811 kW | 24.3 MWh |317 kW	1697 kW | 23.9 MWh | 352 kW

Table 4-5: The (optimal) system configurations for each pricing year (for Joule-based heat pricing)

Here we see what the capacity allocation algorithm found as the optimal system configurations. The major trend is that the 2022 pricing year (the one for which the system is most feasible) has a very large energy storage amount. This is due to the high seasonal price-variations that year.

The 2023 scenario on the other hand, has a large emphasis on investing in electrolyser power. Likely in order to utilize the intermittent dips into negative pricing that occurred that year.

To find the heat recovery contribution, the scenarios were all run with zero HR (also being capacity optimized for zero HR), and the difference in "profits" were found. The following values is the "performance decrease from removing HR". Representing the "value of heat recovery" for the H_2 system in each scenario.

Heat recovery contribution for the H_2 storage and CHP system (with Joule-based heat pricing)

System spec. → Pricing year ↓	2023 system specifications	2030 system specifications
2022 HR-contribution	62%	46%
2023 HR-contribution	52%	40%

Table 4-6: System results (with Joule-based heat pricing) | Money Made, in GBP/year.

For Joule-based heat pricing, roughly half of the performance disappears when HR is disabled.

4.4.2 Results with COP-based heat pricing

It is expected that performance will take a large hit when COP-based heat pricing is the case. However, to what degree, and how much HR continues to contribute, is not necessarily straightforward, due to the relationships discussed in section 2.10.

Money saved by the H_2 storage and CHP system (COP-based pricing)

System spec. → Pricing year ↓	Conservative	Optimistic
2022 money saved [GBP]	51162 GBP (11%)	64384 GBP (14%)
2023 money saved [GBP]	28755 GBP (12%)	37158 GBP (15%)

Table 4-7: System results (with COP-based heat pricing) | Money Made, in GBP/year.

As COP-based heat pricing is introduced, we see that the systems overall performance (money saved) is reduced by a factor by about 0.5 to 0.7. However, since the overall cost spent on energy is that much lower now (with about 80% of energy being for heating, which is now a lot cheaper) we have that it saves relatively more in terms of much it reduces energy expenditure.

Another difference is that the optimistic efficiencies system now has a definite advantage over the conservative one, whereas with Joule-based heat pricing they were fairly close.

While it takes a higher share away from energy expenditure, it has however a much-reduced performance relative to its CAPEX (as mentioned, 0.5 to 0.7). This means, that it looks like the system is far out of being in contention for 2023 prices and likely the same, even for 2022 as well. As mentioned, it seems that a price decrease beyond what is predicted for 2030 will be needed. But the results also show that the heat contribution of the systems aren't as different as expected between vastly different system configurations, at least for COP-based pricing. Likely due to HR no longer being a decisive factor in how the system operates. Being more like an "add on" feature instead of a dominating one as it was for Joule-based heat pricing.

Thus, the HR results could still be quite accurate, even into a future where the combination of price-volatility and much further reduced component costs could occur.

Years to recover component CAPEX (with COP-based heat pricing)

System spec. → Pricing year ↓	2023 system specifications	2030 system specifications
2022 CAPEX/(money saved)	37	30
2023 CAPEX/(money saved)	67	52

Table 4-8: System results | Money Made, in GBP/year.

If there ever will be such a scenario (in terms of component cost and price volatility), the following is the optimal system configurations for different years.

System configurations for each system (with COP-based heat pricing)

System spec. → Pricing year ↓	2023 system specifications [ELY input, HHV storage, FC output]	2030 system specifications [ELY input, HHV storage, FC output]
2022	851 kW | 65.6 MWh | 368 kW	803 kW | 67.3 MWh | 366 kW
2023	1920 kW | 26.4 MWh | 254kW	1799 kW | 25.4 MWh | 295 kW

Table 4-9: The (optimal) system configurations for each pricing year (for Joule-based heat pricing)

It can be seen, that very large storage amounts are prioritized even higher for the 2022 set with this heat pricing. Maybe because the lower r_P value leads the system to become optimized for an even more seasonal type of storage. The capacity algorithm is forced to adapt even more towards that due to the lower r_P. (See section 2.10 for r_P explained).

Heat recovery contribution for the H_2 storage and CHP system (with COP-based heat pricing)

System spec. → Pricing year ↓	2023 system specifications	2030 system specifications
2022 HR-contribution	26%	16%
2023 HR-contribution	27%	14%

Table 4-10: System results (with Joule-based heat pricing) | Money Made, in GBP/year.

As for heat recovery dependence, it seems to still be fairly substantial. Depending on how far it turns out that such a system should be allowed to degrade, it seems like HR will stand for about $1/5^{th}$ to $1/4^{th}$ of the performance contribution, even with low (pessimistic), purely COP-based heat pricing. Roughly 20% on average. Potentially more than this, depending on how far it makes sense to let the system degrade before replacing PEM components. *This is equivalent to a performance increase by a factor of 1.25.*

4.4.3 Results compared to Li-ion

While the focus of this thesis is not the direct competition against other storage methods, it will still be mentioned shortly here. Keeping in mind, that doing a true "apples to apples" comparison includes a vast scope of things not discussed below. The performance (money saved) is not the full story. That would include a full cycle life analysis with cycling patterns, life-time degradation, more advanced optimization models, sustainability of replacing parts intervals, and more. The relative performance will still be given here, and then their respective patterns of operation.

Percentage of money saved compared to Megapack with Joule-based pricing

System spec. → Pricing year ↓	2023 system specifications	2030 system specifications
2022 – % of MP performance	27%	29%
2023 – % of MP performance	27%	30%

Table 4-11: Percentage of money saved compared to Tesla Megapack, for Joule-based heat pricing

Percentage of money saved compared to Megapack with COP-based pricing

System spec. → Pricing year ↓	2023 system specifications	2030 system specifications
2022 – % of MP performance	14%	17%
2023 – % of MP performance	16%	21%

Table 4-12: Percentage of money saved compared to two Tesla Megapacks, for COP-based heat pricing

The large li-ion battery here is of similar cost as the H_2 components. But with major associated costs left out for the H_2 system, such as additional BOP for the full system, DHN integration and installation. The li-ion battery cost is also without installation though, which would stand for an additional 60% cost in its case [40].

It can be seen that the Megapack has about 3.5 times the performance with Joule-based heat pricing, and around 6 times with COP-based. If the H_2 system is to become a competitor, the first thing that would have to happen is component costs being reduced well below the predicted 2030 levels assumed in this thesis. However, this does not necessarily need to happen to the degree where H_2 beats li-ion in outright performance.

If an H_2 system becomes somewhat viable, it is then (amongst many other things) a question of system lifespans. Which for both depend heavily on cycling. Operational patterns for li-ion is seen in Figure 4-10 and Figure 4-11 below. And in Figure 4-12 and Figure 4-13 for the H_2 system.

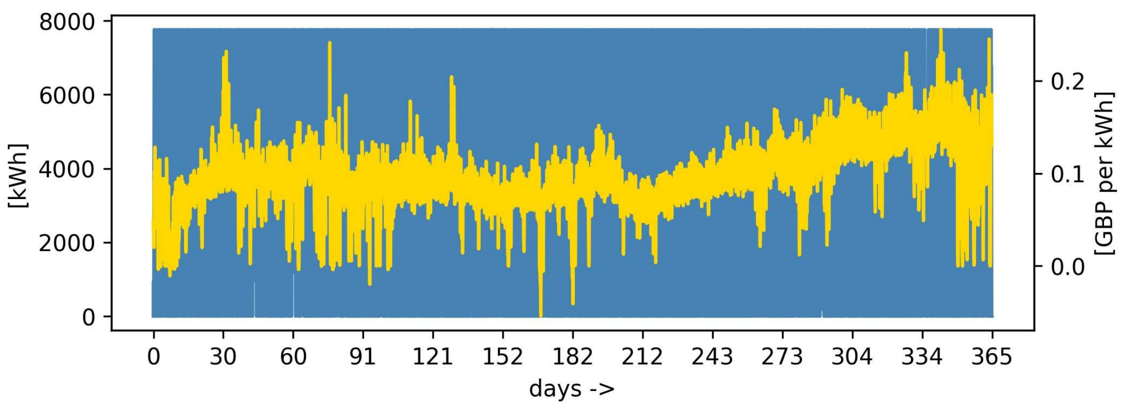


Figure 4-10: Li-ion cycling in 2023 ↑

Where the blue line is the charge state of the systems, and the yellow line is the cost of electricity.

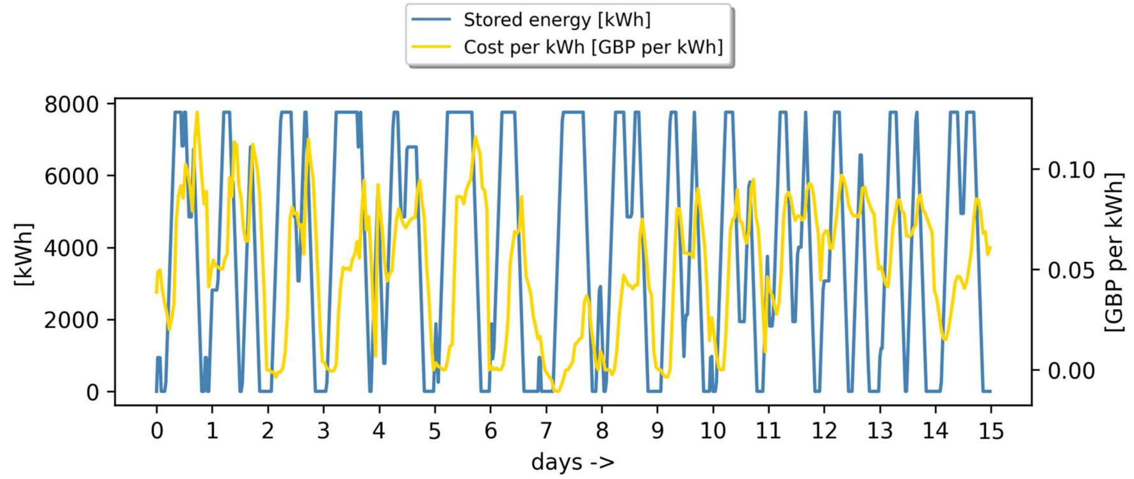


Figure 4-11: Li-ion cycling, 15 days in January ↑

The li-ion system (above) can be seen to cycle once or even twice a day for the performance found for it. This is a very intensive operation that can impact its lifespan, after which the entire system has to be replaced. Battery lifespan is often given in amounts of cycles.

Meanwhile, the H_2 system (below) is a much more intermittent, larger capacity and long-term type of storage system. In order to truly compare the systems, this as well as many other things previously mentioned should be collected into a large and many-faceted analysis.

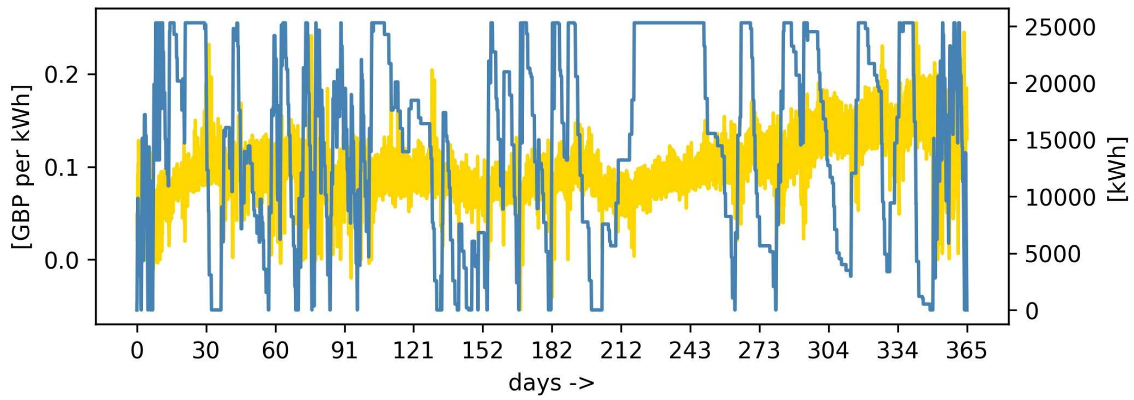


Figure 4-12: H2 cycling in 2023 ↑

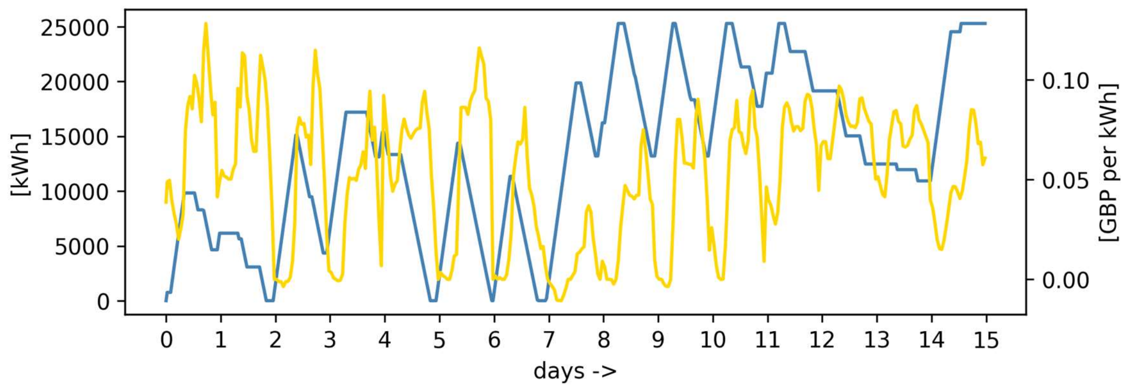


Figure 4-13: Li-ion cycling for 15 days in January ↑

4.5 Case 1 Results Discussion and Summary

The focus of this case study was to find the HR contribution of such a system. It was found to be roughly 50% for a Joule-based heat price, and roughly 20% for a COP-based heat price.

Based on the “years to make back component CAPEX”, it was also found that the system is far removed from a chance at being feasible for 2019 price-volatility. For 2023 and 2022, things were drastically better than for 2019. However, it was deemed that significant reductions in component costs beyond those assumed here will be needed if such a system is to become feasible. If such prices ever manifest, the further competitiveness of the system against Li-ion depends on a few additional factors. Mainly the lifespan and sustainability of the H_2 components, and what types of electricity price-volatility the future holds.

It has however been found out, that if this technology will ever be relevant, then the contribution of heat recovery can boost its performance by a factor of about 1.25. (Standing for 20% of the performance). This is for a low, COP-based heat price that in reality is seen as likely to have DHN grid-tariffs on top. The 1.25 figure is thus considered a conservative lower estimate.

The 1.25 factor also depends on the level of degradation that is to be allowed. For reference, the fuel cell (which stands for majority of the HR-contribution) had an 18% efficiency degradation between the two system specifications that were investigated. Considering the relatively small reduction in “money saved” (13% for 2022 and 19% for 2023, for COP-based pricing) between the optimistic and conservative system, it is found likely that such a degradation level is reasonable. Possibly a small one.

Exactly what HR-contributions one can expect, depends then on many things. But this thesis proposes that 20% HR-contribution (or a 25% increase from adding HR) is a conservative measure, regarding the pessimistic purely COP-based heat price, and what is assumed reasonable or low levels of degradation. The primary result of case 1, is:

A 25% performance increase from the addition of HR is considered a low-end, conservative estimate for an H_2 energy storage system and CHP.

If this type of energy storage becomes relevant, it will likely be decisive to implement it where HR can be utilized, even with low, COP-based heat costs.

5 Case 2 – Hydrogen Fuel Production With Heat Recovery

Much like the case study 1, this chapter will be split into four categories

- Introduction, summarizing the case setting.
- Case setup, dimensioning the H_2 fuelling facility.
- Optimization model formulation.
- Results and discussion.

5.1 Introduction

The case will investigate a fuelling station for express boats in Trondheim, Norway. The case will be set up, so that it will determine the value of heat recovery for such a facility.

Much like case 1, this will be done for a system configuration (FC and ELY power, as well as storage capacity) that are purported to be "realistic". However, in this case it will not be a rigidly defined "optimal configuration" found by the capacity allocation algorithm. Reasons why is due to results presented in in sub-sub-section 5.4.1, of the results sub-section.

The case will be run for the same three pricing years, and the two 2023 and 2030 states of technology. The energy flow chart of the H_2 system now looks like this:

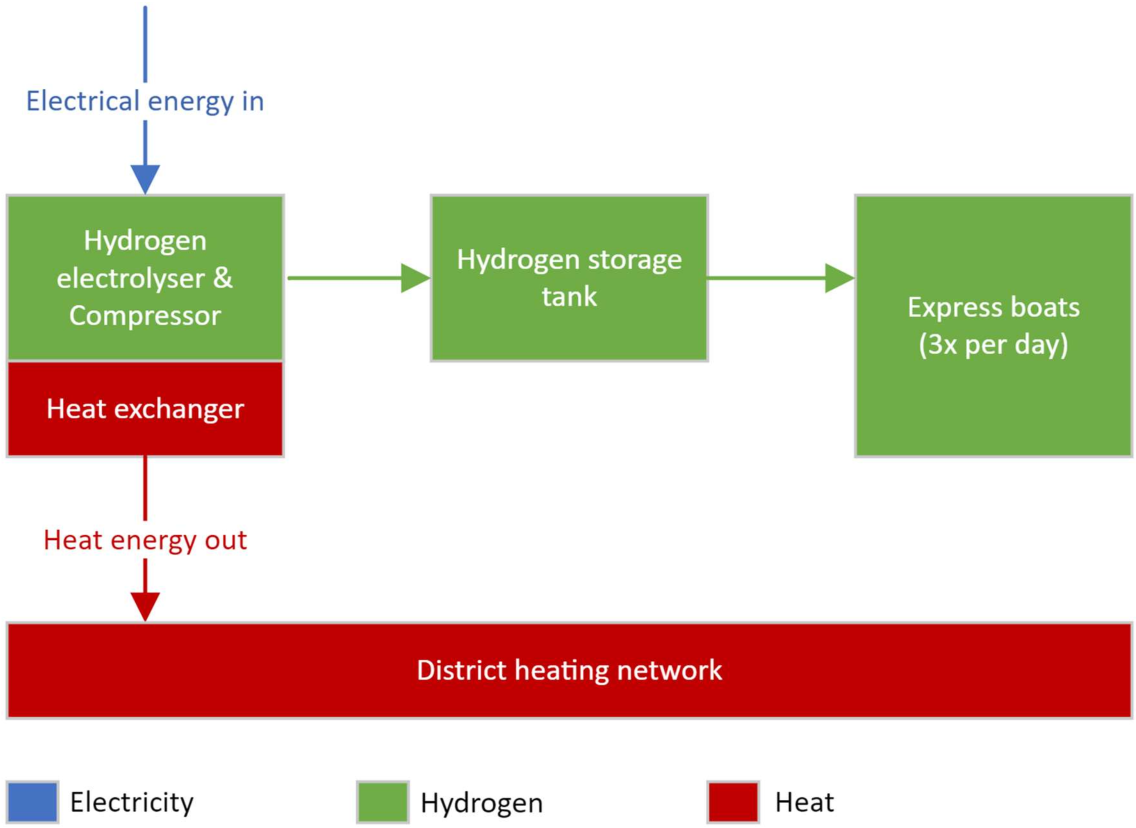


Figure 5-1: Case 2 Fuel Production Facility Energy-flow

The DHN part, which (like case 1) is the part that the optimization model is considering, is the "distribution network" shown in Figure 5-2 below. The difference here is naturally that there is only one heat by product variable.

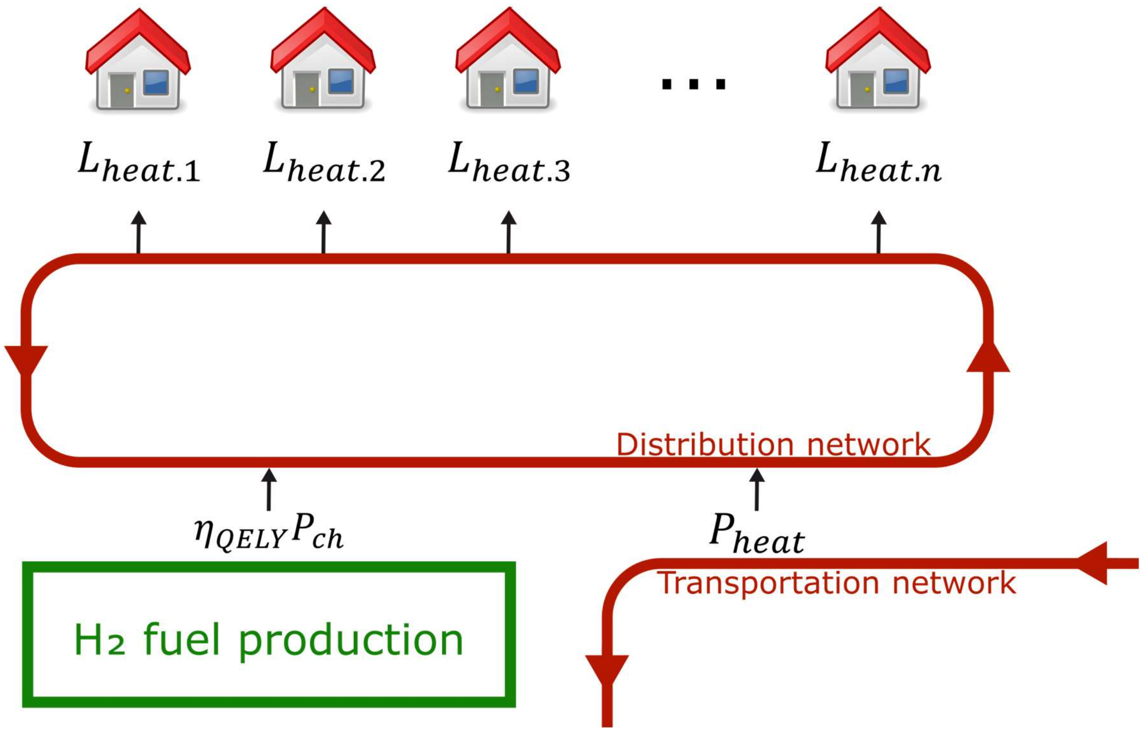


Figure 5-2: DHN of Case 2.Credit for "House icon" SVG-file: OpenClipart [13]. Rest drawn by author.

5.2 Dimensioning the H_2 fuelling facility

5.2.1 Energy demand, bunkering capacity and fuelling schedules

In the 2017 SINTEF paper, a storage amount equalling that of 2 days was chosen. In the case of a production halt. This way, there is time to fix the halt, and/or to provide H_2 from other sources, if the production system has an unexpected down-period.

In the SINTEF study, a consumption of 6000 kWh per trip is assumed [57]. This based on the energy consumption of a light-weight carbon fibre composite speedboat from 2014. Some improvements in boat efficiency may be envisioned, but in consultation the district transport agency, a similar efficiency to the existing carbon fibre ship was assumed in the 2017 study.

Further, a fuel cell efficiency of 15 kWh/kg H_2 was assumed. This corresponds to 45% efficiency for an LHV-based unit (operating above 100°C) or 38% efficiency for an HHV-based unit. This is on the lower end of efficiencies achieved/demonstrated for actual operations pre-2023 (40 – 60%) [116].

An in-depth study of fuel cell degradation together with fuel cell efficiency developments between 2017 and 2035, coupled with adjusting any other relevant estimations from the SINTEF study, could be done to produce a more accurate and assured fuel storage requirement for 2035.

However, detailed literature to back up a replacement for the 2035 equivalent to the 15kWh/kg figure, was not found at the time of writing. More-so, there are very many factors at play when it comes to estimating the actual fuel consumption and thus storage requirements in 2035.

Doing this would be a large body of work in its own right, and the resources needed to do it accurately is deemed "not yet available", as the development of various technologies that may affect it is hard to determine.

For this case study, a more superficial estimation will be done. A reduction factor based on the increase in efficiency of fuel cells will be applied. From 2021 to 2030 efficiencies are purported to go from 56% to 68% (LHV) (based on PEMFC specs cited in case 1). These are not the expected average efficiencies of the boats themselves, but this ratio will be used to account for the change in fuel cell efficiency for the boats in this case.

This ratio would lead to a 18% decrease in fuel consumption. This is considered conservative, as it is based on efficiency-figures representing 9 years of development, while the actual timespan is assumed to be about 18 years. From the 2017 SINTEF study to ca. 2035. However, a conservative estimate seen as suitable, regarding potential high fuel consumption in heavy seas/weather. As well as having a larger margin for fuel cell degradation. The following figures were adjusted by 20% to estimate potential 2035 values:

Estimation	2017 Value [57]	Adjusted 2035 Value
H_2 per trip (Trondheim – Kristiansund)	400 kg	320 kg
H_2 per trip, with buffer	450kg	360 kg

Table 5-1: Fuel consumption of H_2 express boats per trip – estimate

This is however a very large energy requirements per fill-up. 14.18 MWh (HHV). As mentioned, the chosen storage amount in the SINTEF study was equal to 2 days. This choice will be modified for this thesis. It is assumed that in 2035 and beyond, one can be more dependent on H_2 being produced elsewhere for backup, and that 24 hours is enough to provide this (transported from elsewhere). The facility is assumed to be built with dependability in mind. The input to the cost functions will thus specify two electrolysis units each of half the total capacity.

The fuelling schedules are assumed to be the same departure times as today: 8:10, 12:15 and 16:25. Three departures daily. The storage rule is defined as: At the start of any tanking, 4*14.18MWh = 56.7 MWh should be stored in the tanks.

Finding the theoretical minimum storage and electrolyser capacities

Because the model operates in 1-hour intervals, whereas the boats will fill up in 20 minutes, the theoretical minimum values for the tank size and electrolyser power will be established symbolically. This will "cut off" the model for the fringe cases where it returns a system configuration (system parameters) as feasible even though it shouldn't be. This avoids rather unnecessarily running the model with 3 times as many variables, improving solve-times.

The minimum storage was set to 56.7 MWh. It has to hold 3 fill ups at the end of the "current fill up", was the rule. This would mean that the electrolyser would have to produce 14.18 MWh in less than 3 hours and 40 minutes between fillings. The electrolyser power would then be 3.87 MW output. Which then has to be divided by its efficiency (HHV). This system would then be constrained to do most of its charging in between fuelling times, as the tank volume wouldn't allow for anything else.

As for the minimal theoretical electrolyser power, it would be 1.80 MW (3*14.18 MWh/ 23.66h) divided by its electrochemical efficiency (HHV). The related storage capacity would however in that case have to be 94 MWh. This system would be constrained to charge continuously.

Neither of these minimum cases would have any freedom in the operation patterns of the system. No room to utilize price-volatility. They will thus lead to much higher energy costs, and the system configuration that will be chosen is something in between these. Something that is dimensioned larger than a minimal feasible set of capacities, so that it may achieve a low OPEX through optimized charge-patterns.

5.2.2 Production and storage facility description

Storage

The storage facilities will be located in each city (the route endpoints), to reduce tank weight and size on the ships themselves. In the SINTEF study, 4 alternative layouts were proposed, one of which resembles this.

There, a low-pressure storage was considered. Twelve 45 bar tanks, 3m in diameter and 13m long were proposed. The area estimation 40 by 25 meters, for everything including 12 of said large storage tanks, the electrolysers, and dispensers. This however being for a study that assumes about twice the storage capacity. This thesis assumes lower energy demand from the boats (20%) and also a less conservative safety margin for storage, due to the new 2035+ setting.

The volume requirement would still be massive. 56.7 MWh (HHV) equates to 1440kg of H_2. Which would be 5 of the described low-pressure tanks. The actual storage amount will however be decided based on the optimization model and is (as mentioned) likely larger.

More compact storage would however allow for this amount to be stored in three 20ft MEGHC container-units at 500 bar (as per the composite tank NPROXX solution) [102]. Or, five 20ft containers of multiple type I (all-metal) tanks at 300 bar (see citation for images, if links are still up) [97].

EHC (electrochemical hydrogen compression) is still in a developing stage when it comes to size and scalability. Part of the reason that the scenario in the SINTEF study had very large low-pressure tank, as well as a relatively low 250 bar pressure for the boats themselves, is likely the overly expensive, large, and inefficient mechanical compressors that were available at the time of their study. There are also serious safety concerns regarding these mechanical compressors. It is assumed that for a 2035+ scenario, EHC compressors will be available (as done for case 1). A compression of 350 bar will be assumed for the storage solution in this thesis. This way, the tanks can be shrouded in a dedicated building or underground concrete structure, avoiding a large number of 13-meter-tall tanks by the port.

On a proposed express boat solution (from DNV GL's green shipping program) for the Florø – Måløy route in western Norway, 250 bar tanks were proposed. This was also the basis in the SINTEF study. Calculations (as per the method described in section 3.4) show that pressures of 250 bar, 350 bar and 500 bar have factors on the overall systems (electrochemical) efficiency of 95.7%, 94.9% and 93.3% respectively. (Assuming a low current EHC). A tank pressure of 350 bar is seen as a good middle ground.

5.2.3 Compression and dispensers

In order for the boat tanks to fill up fast, dispensers with compressors are needed. A high pressure in the storage tanks is positive in this regard. So is a high volume. The specifics of the dispensers will not be considered in detail in this thesis. It is assumed to not be of interest to use EHC with heat recovery for example when it comes to this. Rather, equalisation of pressure from a MEHGC sitting somewhat above the pressure as the boat tanks could be employed.

5.2.4 Choosing an electrolyser

This scenario will require a large-scale electrolyser. SINTEF's alternative B (the similar concept to this) proposed two 1MW units from of the NEL A-485 type. This is an AEL unit working on atmospheric pressures. It's cell stack efficiency corresponds to 73.5% (LHV-based). But this is the cell stack. Efficiency including BOP is not given.

Alkaline units have been the standard for large MW-class units traditionally. However, by the model by Reksten et. al. (described in section 2.5.3), PEMEL is predicted to cost less than AEL "in the range up to 10MW in 2030" [79, p. 38112].

However, a major consideration is the output temperature of the water to the DHN.

The third gen. network in Trondheim, has traditionally the following two operating temperatures. The distribution networks operate at "up to 100°C" (being the maximum the pipes are dimensioned to handle). The transportation networks (going from high heat centrals to the more local network loops) however are pressurised and have an output temperature from heat sources, as high as 115°C, with return temperatures of "no more than 65C. However, conferring with Statkraft (the local DHN provider) by e-mail, they said that they are now operating with "60 out, 40 in" for their distribution networks. This means that PEMEL and AEL are qualified in terms of output temperatures.

PEMEL is the chosen technology for the electrolyser. Mostly based on Reksten et al.'s prediction that it will out-compete AEL in price. More so, it is much more suited to HR due to its much more compact cell stack (minimizing losses). The output temperature from PEMEL can (as cited to earlier) be up to 75°C.

The facility then, has to be connected straight into a distribution loop. It would have too low temperatures for the transport network. If the electrolysis was to be by the SOEL process, then using it for providing heat to the transport network (going out to other city districts) could be done. But this will not be considered here as SOEL is likely not competitive with PEMEL for the fuelling station operation.

Calculations were done regarding the possibility of using a high temperature heat pump. However, this was found to negate about two thirds of HR profits, if heat is to have a COP-based pricing while electricity to run the heat pump has not. Implementing it was seen to reduce HR earnings by a factor of 0.29.

Thus, it is settled on PEMEL and a 4th gen DHN (distribution loop).

5.2.5 Heat Uptake

To be able to model the DHN efficiency well, the heating demand should be well known. However, there is no way to predict the heating demand of a future district. The only available data is that for the three Brattøra "plus-buildings" we currently have data for.

What has been done in this case study, is to take the heat demand in the distribution network from Renewables.ninja and setting it to correspond to domestic heating for 5000 people. This is likely not entirely accurate for a 2035 scenario at Brattøra, which in time will get filled with both apartments and office buildings. But in lack of better options, the heat demand is approximated by this renewables.ninja data. This data is also for a "Norway average". Not for "by the fjord in Trondheim" specifically. The main purpose of this data is however to limit the system in a realistic manner when it comes to the summer months for example.

The figures below, show the district in question. Figure 5-3 shows it in its current state, and Figure 5-4 shows potential development plans. The three buildings circled in red have a 0.9GWh yearly consumption. The express boat terminal can be seen on the lower right-hand side.

Figure 5-3: The building group with the 0.9 GWh/year heat demand as of 2024. Express boat terminal seen to the lower right-hand side in the marina. Image Credit: Google Maps

Figure 5-4: Current plus-houses with new suggested example developments surrounding it. Express boat terminal seen on lower right-hand side. Image Credit: Adressa [117]

Norway's largest indoor swimming pool with a yearly heat demand of 6 GWh is also located nearby. In addition to this, the building mass in the area is set to increase by about an order of magnitude compared to the 0.9 GWh of demand from the three buildings encircled in red.

Meanwhile, the heat by-product from electrolysis is estimated to be around 2 – 4 GWh yearly. It is thus seen as realistic that there is more than high enough uptake for heat even in the local distribution network only.

Demand data equalling 5000 domestic inhabitants might not be a very accurate representation when it comes to hourly demand data for this district, but the data is however seen a good approximation when it comes to seasonal demand, which will be the main limitation for the system when the total uptake is assumed to be as large as described above.

The system is in any way not thought to be limited due to daily variations outside this. Figure 5-5 below shows the current speed boat terminal being connected to the distribution network.

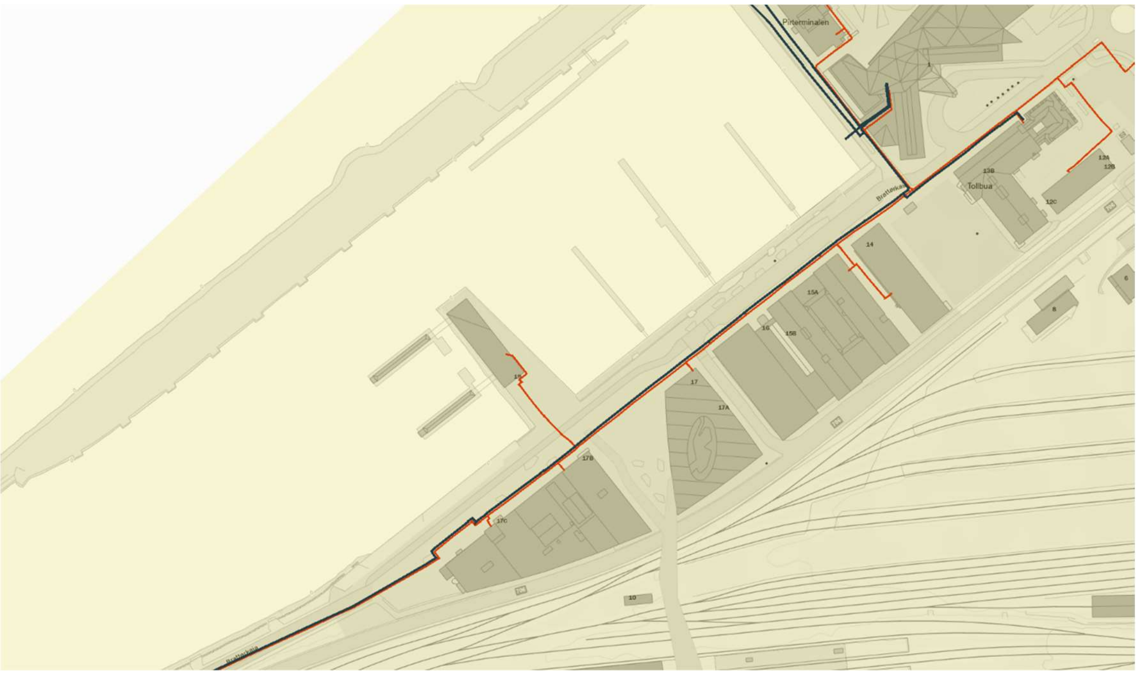


Figure 5-5: Map of current DHN infrastructure around the speedboat terminal (in the middle of the marina). Image Credit: Statkraft [118].

In the conversation with Statkraft, they also mentioned the development of a low temperature network at "Nyhavna", a new city district development across the river from Brattøra. This DHN project will also include seasonal thermal storage. This is however located across the river. But establishing DHN pipes across bridges is something that is done several other places in the city. This could potentially increase usefulness of the H_2 heat by-product, storing it from summer months until autumn for example. Modelling this falls outside the scope here, as it was found out about towards the latter phase of the project. It is still mentioned, as a potential way to increase the value of HR from the H_2 station. It has to produce a heat by-product all summer long anyways. On that note, thermal storage at Brattøra as well could also be opportunistic if an H_2 production facility was to be created here.

5.2.6 Establishing DHN scenario and efficiency for case 2

This was established in the theory chapter regarding DHN efficiency. It is approximated using an estimate of the yearly average efficiency of the distribution network.

$$\eta_{DHN} = 0.90$$

5.2.7 Final system and case setup description

For this case, the same PEMEL specifications as in case 1 will be used. Like for case 1, Joule-based and COP-based heat pricing will be investigated, and a 2023 and 2030 state of tech will be investigated. As done for case 1.

The increase in heat recovery between the two states is a bit less than a doubling (see table below). A doubling, is what Jonsson and Miljanovic quotes for the HR for their electrolyser over its lifetime [112]. If that is used for reference, averages of the following results could be seen as slightly conservative estimates of the average HR-contributions for the system. Although, any in depth degradation analysis or predictions will not be done here.

System Specifications	2023 specification	2030 specifications
Electrolyser efficiency pre-compression	0.697 (HHV)	0.77 (HHV)
Electrolyser efficiency incl. compression	0.652	0.737
Electrolyser heat recovery	0.22	0.13
DHN efficiency	0.90	0.90
HR efficiency post-DHN	0.198	0.117

Table 5-2: System specifications for case 2

The system capacities will be dimensioned based on the conservative system specification, with some margin. The dimensioning of the system capacities is seen as part of the results, as it is a result from the lin. prog. model. It is thus placed in the results section below.

5.3 Optimization model for case 2

5.3.1 Nomenclature for case 2 optimization model

Variable	Entity/Explanation/Comment	Type
$\boldsymbol{P_{charge}}$	Charge power [kW] or [kWh/h]	Variable
$\boldsymbol{P_{charge.to.HR}}$	Portion of charge power going to HR	Variable
$\boldsymbol{P_{charge.to.curtailment}}$	Portion of charge power being curtailed (instead of going to HR)	Variable
$\boldsymbol{C_{electricity}}$	Electricity price [NOK]	Data
$\boldsymbol{C_{DHN}}$	Price for delivered DHN heat	Data
$\boldsymbol{L_{heat}}$	Heat demand	Data
$\boldsymbol{\eta_{DHN}}$	Efficiency of the DHN network	Constant
$\boldsymbol{\eta_{ely}}$	Electrochemical efficiency of the electrolyser	Constant
$\boldsymbol{S}$	Storage tank charge level [kWh]	Variable
$\boldsymbol{T}$	Tanking amount withdrawn from storage [kWh]	Data
$\boldsymbol{P_{max}}$	Electrolyser Maximum Power	Constant

Table 5-3: Case 2.1 Optimization Model Nomenclature

5.3.2 Optimization model formulation for case 2

Objective Function

Minimize:

$$\sum_{t=1}^{8760} P_{charge}^{i} C_{electricity}^{i} - \eta_{QELY}\eta_{DHN}P_{charge.to.HR}C_{DHN}^{i} \qquad (5\text{-}1)$$

Subject to:

Charge Level Balancing Constraint

$$S_0^i = S_{start}^i \quad \forall i = 1, \dots, n \qquad (5\text{-}2)$$

$$S^i = S^{i-1} - \eta_{ELY}P_{charge}^{i} - T^i \quad \forall i = 1, \dots, n \qquad (5\text{-}3)$$

Minimum Storage Amount Constraint

$$S_i > S_{min} \qquad \forall i = 1, \dots, n \tag{5-4}$$

Charge Power Constraint

$$P_{charge}^{i} \leq P_{max} \qquad \forall i = 1, \dots, n \tag{5-5}$$

Heat Demand Constraint

$$\eta_{DHN}\eta_{QELY}P_{charge.to.HR}^{i} \leq L_{heat}^{i} \qquad \forall i = 1, \dots, n \tag{5-6}$$

Charge Sum Constraint

$$\eta_{QELY}P_{charge} = P_{charge.to.HR} + P_{charge.to.curtailment} \qquad \forall i = 1, \dots, n \tag{5-7}$$

5.3.3 Explanation of constraints and objective function

Most of the above constraints are self-explanatory. A notable difference from the first case study, is that the heat demand constraint is now lower than or equal to, instead of higher than or equal to. The case 2 system is not responsible to provide heat (like the case 1 model), it is only going to sell heat in conjunction with H_2 production, making sure it doesn't overflow the DHN with heat.

The Charge Sum Constraint automatically makes sure that the produced heat corresponds with that which the electrolyser actually produces.

As for the objective function: This is to be the cost of energy used on fuel production. Which is set to the cost of electricity, minus the revenue from sold heat. This heat is, as before, reduced by the inverse of the COP, DHN efficiency.

The python code for the model can be found in Appendix A.

5.4 Case 2 Results

5.4.1 The system capacities and configuration

The result section will start with establishing a realistic system configuration as this is also a "result" from the model. This time the starting point is not to find the best system configuration for a set CAPEX, but to find the best system that can meet the fuel production requirements.

This would be the system that had the total lowest cost over its lifetime. Or CAPEX + OPEX. Finding an exact answer to this is however complex, difficult, and unpredictable. It is a question regarding system degradation, the different cycle lives of part, electricity pricing predictions for decades ahead of time, and a economical investigation into the full H_2 charging station including civil works, power grid upgrades, maintenance and installation. Not to mention the sustainability considerations around saving money on energy-expenditure through installing an overly capable system that would in essence perform the same task anyhow. All in all, the task of solving this problem in-depth has a vast scope, that cannot be undertaken here.

To start considering this, one can look at the energy expenditure and system cost plots, generated by running the model for 120 by 120 different configurations. The plot was defined to go up to 4x the minimum viable value for each system capacity. See Figure 5-6 and Figure 5-7 below.

Looking at Figure 5-6 and Figure 5-7 below we can see that the optimal choice from each point of view, is in opposite ends of the plot. So, it depends then, how heavily each is weighted. This is again a question regarding the vast scope that would be solving this problem in depth.

A simplification has to be made. The total system cost + energy-costs for 20 years (of 2023 pricing) for the conservative system will be used as a simplified benchmark.

Since the CAPEX here represent only the electrolysers, EHC and tanks, and the total cost of the facility will likely be a lot higher, it is found reasonable to choose system capacities farther towards the lower left-hand corner than the red dot. The total cost there is not much lower than the optimal one, and accounting for the considerations mentioned above, a smaller system would undoubtedly be considered the better one. Sustainability (needing to purchase and replace less components in the long run), as well as avoiding using excessive space for an H_2 fuelling station in one of the city's most developing areas, are seen as unambiguous reasons for keeping the system configuration near the minimum. However, not at the minimum.

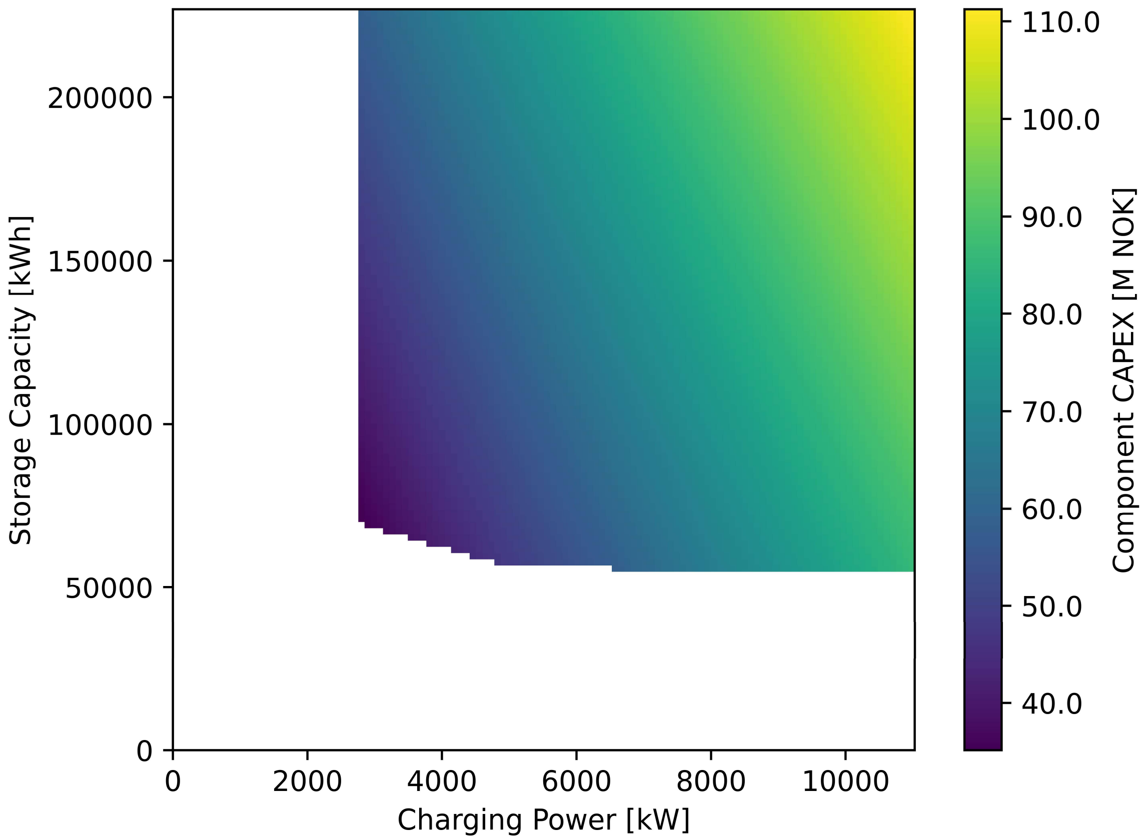


Figure 5-6: Component CAPEX

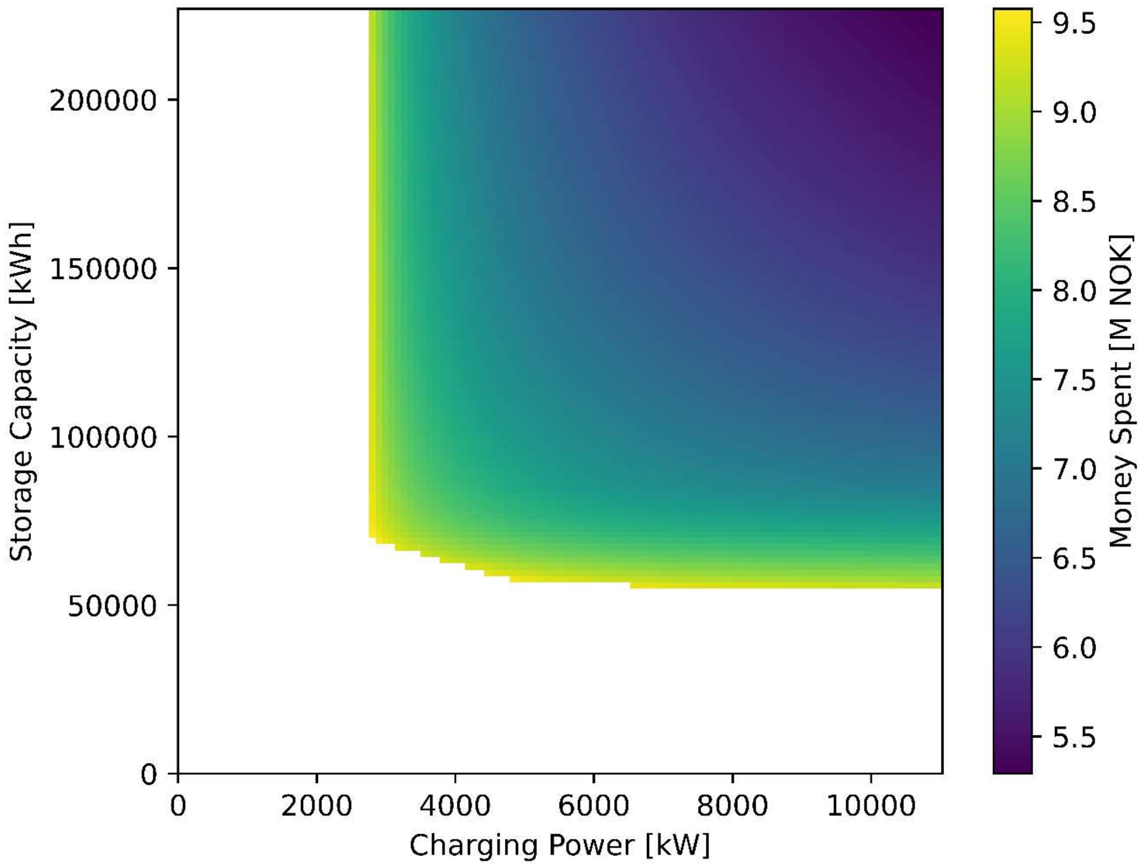
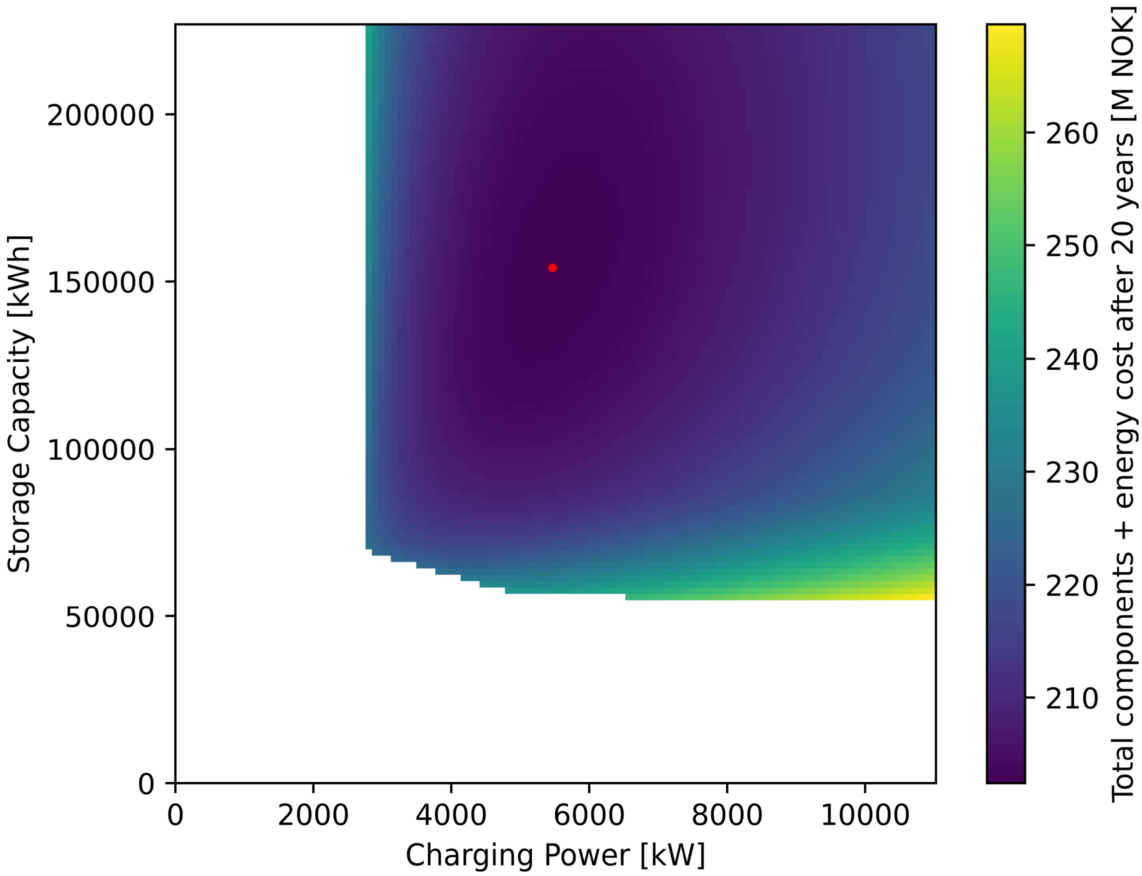


Figure 5-7: Energy costs per year with 2023 pricing



The chosen capacities superimposed over the energy expenditure plot is shown in Figure 5-8 below. The white values are those for which the system is non-feasible: Where it fulfil express boat fuelling schedules. The plot below is for the conservative system in 2023. The values are chosen with some margin into the feasible area to avoid the highest energy-costs. And to allow for the system to function somewhat as a “vector for supply-demand operations”. I.e., to allow it to have some freedom in when to charge. As well as to allow for some additional margin regarding degradation.

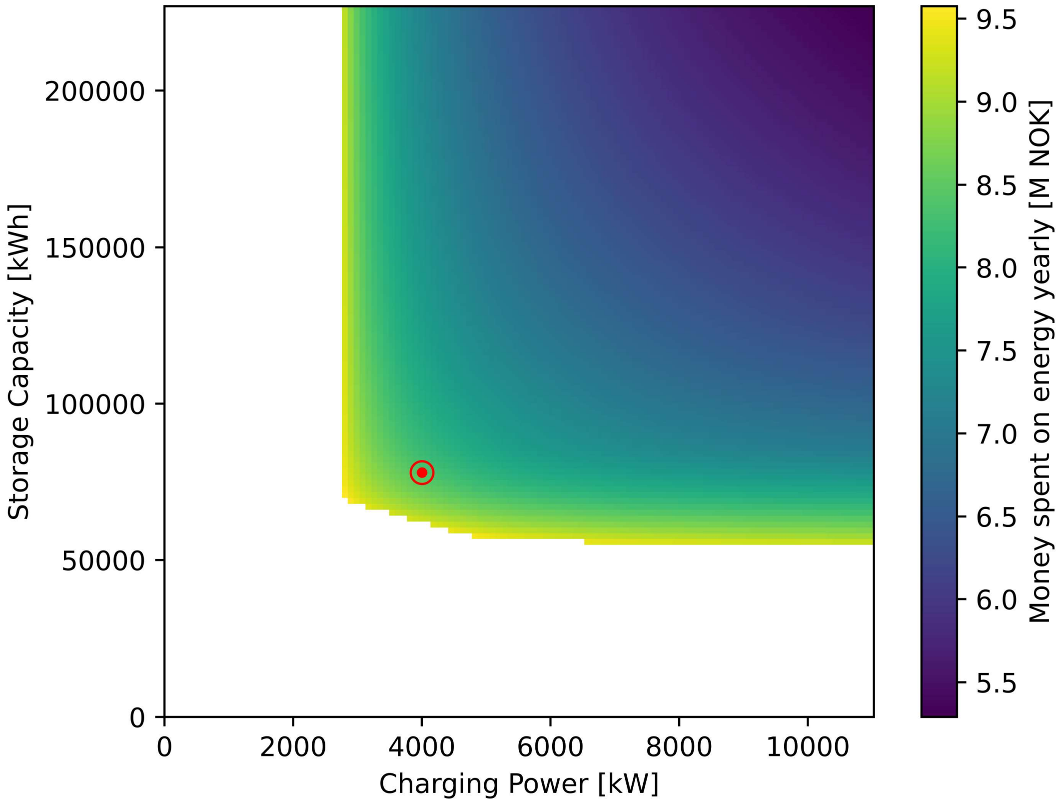


Figure 5-8: Chosen Capacities for H_2 Fuel Production Facility. (Over 2023 energy cost with COP-based heat prices)

The system specifications is as follows:

System electrolyser power	System storage capacity
4.0 MW	78 MWh (Net 26 MWh)[1] HHV

Table 5-4: System specifications for the H_2 production and fuelling station

[1]56.7 MWh buffer (in case of production halts), and 21.3 MWh net charge for day-to-day fuelling.

This would for example amount to four NEL MC250s, or two NEL MC500. The latter totalling a size of four 12.2 m containers. The tank capacity could roughly be housed by two 12.2m containers, plus one 6.1m container. (Assuming the same storage volume as NPROXX’s solution, but scaling it down from 500 bar to 350 bar[102]. *Or this would be 75 MWh HHV to be exact, but accurate enough to demonstrate the rough size of the components).

5.4.2 Results with Joule-based heat pricing

HR savings for the system config, with Joule-based heat prices was as follows:

Relative HR savings, with Joule-based heat prices:

System configuration → Pricing year ↓	Conservative (2023 efficiency figures)	Optimistic (2030 efficiency figures)
2019 % cost reduction from HR	17.7%	10.9%
2022 % cost reduction from HR	19.0 %	11.5%
2023 % cost reduction from HR	18.4 %	11.2%

Table 5-5: HR Savings in the H_2 Fuelling Station Energy Costs

Net savings with Joule-based heat prices:

System configuration → Pricing year ↓	Conservative (2023 efficiency figures)	Optimistic (2030 efficiency figures)
2019 net cost reduction from HR	1.5 M NOK	0.83 M NOK
2022 net cost reduction from HR	1.6 M NOK	0.82 M NOK
2023 net cost reduction from HR	1.7 M NOK	0.87 M NOK

Table 5-6: Net HR Savings for the H_2 Fuelling Station

Where M NOK is "million Norwegian kroner".

Heat by-product from into DHN from system (with operation for Joule-based heat prices):

System configuration → Pricing year ↓	Conservative (2023 efficiency figures)	Optimistic (2030 efficiency figures)
2019 HR output	4.6 GWh	2.5 GWh
2022 HR output	4.4 GWh	2.5 GWh
2023 HR output	4.2 GWh	2.3 GWh

Table 5-7: The HR contribution into the DHN

Total energy costs for H_2 production with HR-savings, with Joule-based heat prices:

System configuration → Pricing year ↓	Conservative (2023 efficiency figures)	Optimistic (2030 efficiency figures)
2019 total energy cost (with HR)	7.2 M NOK	6.8 M NOK
2022 total energy cost (with HR)	6.7 M NOK	6.3 M NOK
2023 total energy cost (with HR)	7.3 M NOK	6.9 M NOK

Table 5-8: The HR contribution into the DHN

5.4.3 Results discussion/summary for Joule-based pricing

With joule-based pricing, where the cost of heat is calculated by the electricity-price at the time of export, the savings are fairly low relative to the total energy costs. Intuitively, they align quite accurately with the HR percentages of the system input at 19.8% and 11.7% respectively. A reason model results are lower than this, can come from the lack of HR-earnings when there is no heat demand. However, this has a small effect due to low electricity-prices in those months. This is especially the case for 2022, which also is the scenario for which it gets closest to the HR energy-efficiency.

In this way, the result is quite benign from the model here. This was quite different in an earlier version of the model where the heat price was fixed for one month at a time, according to the average electricity price. Then, the system could make money by selling heat at a fixed price when the electricity-price was near zero or negative. In that approach, the HR-contribution changed much more with system configurations as well. While this heat pricing actually is more similar to the one implemented in Trondheim today, it was found "unlikely" that the system would be allowed to operate like this in 2035. This approach was thus discarded.

A note about regarding the HR output results, is that the HR output is correlated to the H_2 demand of the express boats. Depending on how the degradation of boat fuel cells aligns with the electrolyser degradation, this might skew the heat total heat output. But since the calculated fuel demand is thought to be representative of the average one, the above HR outputs is thought to be representative of typical actual ones too.

While the savings seem relatively small, they will add up to a sizeable figure of M NOK over the lifetime of the system.

A bit less benign than the HR-percentages above being close to energy efficiencies, is the results when taking varying COP-figures into account. As the heat price being a weighted average of the product of C_{elec}, P_{heat} and $(COP)^{-1}$ over every hour of the year, it is not as easy to predict. It is however expected that savings will go down by a large degree.

5.4.4 Results with COP-based heat pricing

Relative HR savings, with COP-based heat prices:

System configuration → Pricing year ↓	Conservative (2023 efficiency figures)	Optimistic (2030 efficiency figures)
2019 % cost reduction from HR	6.2%	3.8%
2022 % cost reduction from HR	6.9%	4.2%
2023 % cost reduction from HR	6.8%	4.1%

Table 5-9: HR savings in the H_2 fuelling station energy costs

Net savings from HR with COP-based heat prices:

System configuration → Pricing year ↓	Conservative (2023 efficiency figures)	Optimistic (2030 efficiency figures)
2019 net cost reduction from HR	0.544 M NOK	0.293 M NOK
2022 net cost reduction from HR	0.568 M NOK	0.296 M NOK
2023 net cost reduction from HR	0.609 M NOK	0.319 M NOK

Table 5-10: Net HR savings for the H_2 fuelling station

Heat by-product from into DHN from system (with operation for COP-based heat prices):

System configuration → Pricing year ↓	Conservative (2023 efficiency figures)	Optimistic (2030 efficiency figures)
2019 HR output	4.4 GWh	2.5 GWh
2022 HR output	4.4 GWh	2.5 GWh
2023 HR output	4.1 GWh	2.3 GWh

Table 5-11: The HR contribution into the DHN

Total energy costs for H_2 production with HR-savings, with COP-based heat prices:

System configuration → Pricing year ↓	Conservative (2023 efficiency figures)	Optimistic (2030 efficiency figures)
2019 total energy cost	8.2 M NOK	7.4 M NOK
2022 total energy cost	7.7 M NOK	6.8 M NOK
2023 total energy cost	8.4 M NOK	6.8 M NOK

Table 5-12: The HR contribution into the DHN

5.4.5 Results discussion for COP-based heating price

An interesting observation is that the value of HR has gone down by a factor of around 2.75 compared to Joule-based heat pricing, for both the conservative and optimistic systems. The average COP over the year is however 3.10-3.15. This is due to the established calculation of heat price assumed here being more "fair" than using the average COP. It better represents the actual cost of "heating by heat pump", which is higher than simply the average COP.

Savings are however quite low, especially for the optimistic system. If the system was assumed to degrade linearly between the two states above before having their electrolytes/PEMs replaced, then the HR savings from in for example 20 years, would be around 9 M NOK. Whether HR is worth it economically, then depends on whether the addition of HR to the electrolyser and the associated cost increase, would be earned back by adding HR, over the lifetime of the system.

The full electrolyser unit itself (without installation) including EHC but not a DHN-adapted HR system, is predicted to cost 29.5 M NOK. Upgrading it to have HR, must then incur a smaller price-premium than 9M on top of that for the COP-based heat price scenario.

This seems likely to be achievable, considering the electrolyser in any way need a high-performance cooling system. Implementing HR should in any way be a very small fraction of the cost of the full electrolysis system. However, it would depend, for example on whether DHN applicable cooling systems will be mainstream enough for electrolyser producers to offer them, or if it will have to be custom built.

What was found here, was that those savings can lie between 4% and 7% of the total energy costs. They were reduced by a factor of 2.75 by the introduction of COP-based pricing for an average COP or 3.10-3.15.

5.5 Case 2 Results – Overall Discussion

The savings are diminished to almost 1/3rd with COP-based pricing compared to the policy enacted today (Joule-based). From roughly 25 M NOK to roughly 9 M NOK over 20 years for example.

The question whether implementing HR is worth it is complex. The cost of implementing HR to the production facility must be taken into account.

It is seen as overwhelmingly likely that HR would warrant its own implementation with Joule-based heat pricing. However, COP-based heat pricing is seen as the more likely pricing-scenario in the future and is what will be discussed from here on.

What one here can consider, is the cost of installing the same generation capacity in heat pumps. The tariffs on DHN energy, should ideally mirror this cost, and increase the actual earnings one would get through HR. The yearly energy export from the system was around 2.4 GWh for the optimistic spec. and 4.3 GWh for the conservative one. About 3.4 GWh yearly on average. The long-term cost of installing this yearly capacity in heat pumps should be reflected by the grid-tariffs on DHN heating.

However, a simplified estimate of this shows that it would be very low. 3.4 GWh yearly equates to a constant power of 388 kW. If counting 2kW per heat pump, costing a typical 20k NOK over a 20-year lifespan, this would amount to a 200k NOK grid tariff for the system over a year, or 3.9 M NOK over 20 years. Although this was a very simplified estimate, it indicates that such a tariff would go a long way towards making up for the implementation cost of the heat recovery.

It is found likely that installing HR is more than economically warranted, even with COP-based heat pricing. However, the potential utilizing HR is not a decisive factor for establishing an H_2 production facility.

Furthermore, one can consider the societal implications of wasting this much energy as well. 3.4 GWh yearly equals the yearly heat demand of roughly 490 people in Norway (based on statistics found in citations) [119], [120].

When it comes to the question whether HR can make a difference for the H_2 proposition for the next express boat contract, the answer is: Probably not. The savings from HR are seem too insignificant compared to the cost of the fuelling station to make a significant economic difference. (Plot of component CAPEX was found in Figure 5-6.)

6 Thesis Overarching Discussion and Conclusion

The two cases has examined two fundamentally different cases. Surprisingly though, the pricing variations in the countries was not as different as was expected. Mainly due to Norway having its electricity market much more connected to the European one in terms of electricity-pricing for the last few years. But the different nature of the case studies lead to different conclusions on the value of HR for each.

6.1 The implications of the value of HR towards the feasibility of HESS (H_2 Energy Storage Systems)

The first case study found that an H_2 energy storage system (HESS) and CHP needs extreme pricing ratios to close in on being feasible, especially if low COP-based heat pricing becomes the case. As mentioned in the abstract, higher end of heat pricing policy (Joule-based) was included mostly to give an image of how well the HR could do in a best-case scenario, and as a reference for how much COP-based pricing would cut the contribution of HR. But Joule-based heat pricing is not seen as a likely scenario into a zero-carbon future. Neither was entirely COP-based pricing, as “DHN grid-tariffs” meant to mirror the average cost of a heat pump over its lifetime was seen as likely to be added on top of this.

It was found that the system in the energy storage and CHP case was unfeasible in a 2030 scenario due to too expensive components compared to their performance. It was for extreme (2022) pricing fluctuations that it was closest, however. The situation could be bettered, depending on the significance the proposed DHN grid-tariff on top of COP-heat pricing would have, but mostly, extreme reductions in component costs are needed. In the case that it at some point comes close to being economically feasible, it was seen that HR contribution likely can be decisive, with its +25% performance increase. This being a lower end estimate.

It is therefore concluded that HR can potentially play a significant role in deciding whether this kind of system can become feasible. Whether it will be feasible though, is a question that likely will be answered far into the future depending on market trends as well as findings of further research regarding cycle life of components and sustainability considerations.

6.2 The feasibility of HR-implementation on H_2 fuel production

For the hydrogen storage on the other hand, the value of HR was not of great importance for the feasibility of the system itself. The hydrogen production being a constant necessity for a potential express boat, and the HR contribution quite small. It was however found that the HR implementation was likely to be warrant its own existence. Exact calculations on whether it would pay for itself was not performed, but results are seen as indicating, that it could likely do so with a comfortable margin. While, also saving considerable energy amounts that otherwise would have to be generated in some other ways. For example, by expensive water-source heat pumps or electric resistive boilers into the DHN network.

6.3 Conclusion: The importance of HR

Even though HR naturally loses value if assuming COP-based heat pricing, it was found that for both systems, it is likely warranted to attempt implementing it. Although, in different senses.

The exact implications HR will have for the feasibility of using H_2 for either case, depends on a multitude of yet unknown factors described in "further studies". This thesis will conclude differently for the impact of HR for either of the cases.

The conclusion for case 1: H_2 Energy Storage and CHP:

> *Although the value of heat recovery may be heavily reduced by COP-based heat prices, HR still remains a relevant and potentially decisive measure regarding H_2 competitiveness in this space.*

And, for case 2: H_2 Fuel Production:

> *If COP-based heat prices are implemented, savings through HR will likely not be a decisive economical factor in this space. But it will likely more than justify its own existence as a worthwhile utilization of a by-product.*

7 Further Work

7.1 H_2 energy storage and CHP

As mentioned throughout about, pure operational performance is not alone an indicator of the "best" system for energy storage. This depends on a large and complex picture. The body of work to establish this, may however be relevant on certain conditions. It seems that only extreme and seasonal pricing variations, where H_2 tech. can take advantage of its cheap long-term storage, could make it sensible to take up research in this space. In that case however, sustainability analysis of components, together with lifespan analysis of both H_2 and battery systems would be in order. This would require a more advanced and many-faceted model than the one in this thesis.

For example, one could imagine an electrolyser PEM (proton exchange membrane) lasting for 12 years, and it being switched out thrice before the entire unit has to be switched. On top of this, tanks would be switched out every X years, and the PEM components of fuel cells every Y years. Meanwhile, one may change out the entire Li-ion system three or four times depending on the intensity of the operation.

These are things that are up to further work to find and compare. Can lower sustainability impacts of H_2 components cancel out the higher performance of Li-ion at some point in the future? Considering that PEM components are expensive and require rare minerals, this might very well not be the case. However, this is a complex and many-faceted question, where the answer is unclear, especially regarding the sustainability part.

Furthermore, establishing a more realistic version of the results in this study regarding H_2 performance with HR, will become possible once the actually to-be-implemented heat pricing policies reveal themselves. This could improve things quite a bit for the H_2 system, although, the results given here for Joule-based pricing is "beyond" an upper roof when it comes to this.

Further work could also involve developing pricing policies that are fair, based on "heat pumps equivalent heat costs", and researching how these would interplay with heat recovery of different kinds. Regarding this, more accurate temporal modelling of the DHN-related energy streams may also be relevant.

7.2 Heat recovery for H_2 production and H_2 express boats

Regarding H_2 production, estimating the lifetime of components is very relevant, as it would establish the true long-term of cost of H_2 fuelling. While energy costs were found to be surprisingly low for the H_2 boats, the high cost of the H_2 production hardware cancelled this out.

In case 2 it was found that energy costs was actually much lower than for the previous Diesel boats. About 7- 8 M NOK per year for H_2 production, compared to about 21 M NOK Diesel was calculated (not shown in the thesis, but done on the side based on data from the SINTEF study). This was however for the previous Diesel boats. Not the newer Diesel-Battery hybrids. However, as mentioned, heavier express boats use considerably more energy due to poorer hydrodynamic efficiency. Which will at least to some degree make up for H_2 inefficiency in the propulsion system itself.

What truly will be the best option for the express boats themselves is also considered further research. Although batteries seem to be the preferred solution for now, it is not a question with an obvious answer into the future. This is again a complex question including many-faceted technological and economic analysis. One would also have to take into account, that since batteries are in any case not feasible for larger forms of shipping, H_2 production facilities will in any case have to be built. Whether they should be built in locations where HR is possible depends on many factors, although this thesis indicates that the economic incentive to do so is rather small and not a decisive one. But when it makes sense to build them in such locations, it does make sense to implement HR.

Here, further relevant work would again be to establish an actual (fair) pricing model for sold heat. How to calculate it, and what is reasonable to actually implement. If the DHN-tariffs that are supposed to mirror long term heat pump costs are sizeable enough, then maybe adding HR becomes a sizeable economic factor in this space after all.

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