The future of green electrolytic hydrogen production in the Netherlands

Assessing uncertainty for determining a prudent production capacity

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by

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Acknowledgement

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Joerie Kluijtmans
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Executive Summary

The transition to a carbon-neutral power system has become a global imperative, ever more driven due to recent events such as the energy crisis resulting from the Ukraine invasion. The Netherlands, devoted to the large-scale development of offshore wind and solar PV, see great potential in the use of hydrogen as a gas-replacing energy carrier. By utilising peaks in generation from variable renewable energy sources, electrolytic hydrogen production enables a potentially cost-effective and flexible alternative. However, a consensus in the literature exists that valuable renewable electricity should first be used for direct electrification, resulting in a possible lack of electricity for hydrogen production. A knowledge gap has been identified on what this role of electrolysis will be in the future energy system and more specifically, in what quantities electricity can and should be converted to hydrogen. The objective of this research is firstly to provide insights into the prudent capacity for green electrolytic hydrogen production for 2030 and 2040. Secondly, it aims to address the uncertainties in projections of the future supply and demand for electricity and hydrogen and create insights into their relation to the electrolysis capacity. In addition, a specific emphasis will be placed on understanding the role of storage in maximizing the potential of electrolysis.

To this end, a model of the combined electricity and hydrogen system of the Netherlands is constructed in Linny-R, an executable graphical representation language for Mixed Integer Linear Programming (MILP). A vast array of output data from forecasting scenarios is gathered and consolidated to establish the spectrum of input variables. By systematically assessing the uncertainty, based on these ranges of input variables, and the impact, based on a sensitivity analysis, an experiment design is composed to encompass the most complete reflection of all uncertainties within computation limits. Large sets of experiments are run through this design to; 1) generate outcomes regarding the potential for electrolysis, 2) determine the prudent capacity through the mini-max regret methodology, 3) create insights into the most determinant uncertainties and their relation to electrolysis capacity and, 4) determine the extent to which large-scale hydrogen storage affects the potential for electrolysis capacity. Moreover, the concept of mini-max regret (MMR) is used to establish the most prudent capacity. MMR aims to identify the alternative that minimizes the maximum possible regret, referring to the difference between the actual outcome and the best possible outcome that could have been achieved.

The results of this research show that the electrolysis potential increases from 8-12 GW in 2030 to 8-44 GW in 2040. Underlying all results thus is the notion that flexibility, in whatever form, becomes crucial for the Dutch energy system in the coming years. Figures 1 and 2 give the distribution of the regret for each KPI of the compared scenarios. Based on these figures, 12 GW and 38 GW are the most prudent capacities for 2030 and 2040, respectively. However, as the distribution indicates, they are associated with a substantial risk of overinvestment. For 2030, the no-regret capacity to be installed is 9 GW, as there is minimal chance of excessive investment and reductions are thus achieved risk-free. A lesser capacity, on the other hand, increases the likelihood of foregoing possible cost and emission reductions, potentially leading to higher high system costs. For 2040, the uncertainties surrounding the potential for electrolysis capacity increase and the risk of overinvestment with it. As a result, no capacity was identified as a no-regret capacity regarding overinvestment. However, this value for the prudent capacity is largely determined by the impact electrolysis has on the prevention of loss of load. Diminishing this relationship by implementing other flexibility technologies as a loss of load mitigation measure will result in a lower capacity being considered the most prudent and thus less risk of overinvestment. Moreover, the last few gigawatts of the prudent capacities will primarily serve as peak production plants with minimal operational of less than 150 hours in 2040, requiring margins starting at 11.00 EURO/kg to recoup their investment costs. Lastly, the most determinant uncertainties in the establishment of the prudent capacities are hydrogen demand, peak residual load and underground hydrogen storage capacity, of which the first has the highest degree of impact. Every additional 100 GWh of underground hydrogen storage capacity enables 500 MW of electrolysis potential. On the contrary, the installed capacity of other

flexibility technologies demonstrates little to no influence on the electrolytic hydrogen production capacity.

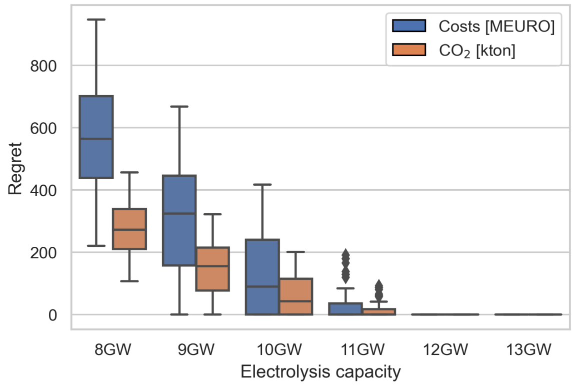

Figure 1: KPI regret values for 2030. LoL is excluded due to its constant zero value.

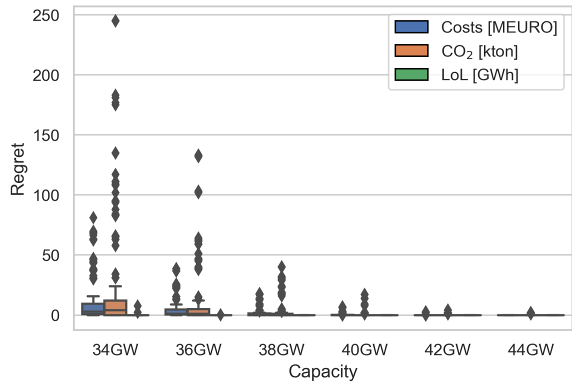

Figure 2: KPI regret values for 2040.

On the basis of these results, we identify three policy recommendations. First, the current ambition of 3-4 GW electrolysis capacity can be prolonged to at least 9 GW in 2030. In doing so, additional investments beyond this target should be encouraged as it will contribute to fostering the Dutch hydrogen economy and addressing the increased potential towards 2040. Second, next to directly stimulating financial investments in electrolysis, a fruitful environment can be created by adopting support schemes that stimulate the most influential uncertainties; hydrogen demand and peak residual load. In addition, flexible system capacity has no impact on the potential for electrolysis and should be deployed to prevent electrolysis from acting as a loss of load mitigation measure. Third, the results showed that the last few gigawatts of the prudent capacities will only be operational for a limited number of hours a year, leading to reduced incentives for investment under current market structures. In order to trigger this last series of investments, we recommend financial measures that either directly subsidise the investment or provide certainty through a market-wide price floor or operator-specific price floor, as a set price or tender.

In addition, four different avenues for further research are highlighted. The first path, originating from a limitation in this work, regards the addition of geographical and grid aspects in the model. This should be performed in three steps; 1) the addition of a transmission electricity grid with demand divided over a handful of regions, 2) the inclusion of hydrogen demand, again divided over a handful of regions, preferably related to the five industrial clusters and, 3) the addition of a hydrogen network. Second, a research avenue exists in identifying what is required to realise investments in the last few GW of electrolysis capacity. This research will consist of a quantitative study into the profitable conditions of an electrolyser and additionally into the design of the market structure and required alternations. In addition, research potential exists in thoroughly analysing the role of large-scale hydrogen storage in the Dutch energy system. Insight can be gained in minimal required capacities from a system perspective, the relation to other flexibility technologies and its role without the availability of SMR. Lastly, further research could explore the role of electrolysis beyond the Dutch national borders in the soon-to-be interconnected electricity generation hub of the North Sea. Within this theme, investments regarding offshore electrolysis and interaction between the neighbouring countries can be explored to help policymakers in their collaboration to find the most cost-effective configurations.

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Chapter 1

Introduction

1.1 Problem definition and context

Over the past few decades, the route to a carbon-neutral power system has become one of the most prominent and complex challenges globally. The energy crisis as a result of the invasion of Ukraine has sent the revolution aimed at phasing out fossil fuels into overdrive. The European Union have been at the forefront of this revolution with the Green Deal, a climate action strategy plan to reach carbon neutrality by 2050 [32]. In response to the recent developments, the European Commission has recently presented the Green Deal Industrial Plan (GDIP). With this plan, the commission aims to relax European state aid rules and accelerate the greening of European industries. Around €270 billion has been made available to the member states [32, 30].

The Netherlands, among the most polluting member states in the Union, is making considerable efforts to contribute to these targets [26]. With, in particular, electricity production being dependent on fossil fuels, ambitions for installed offshore wind power capacity in 2030 have been doubled from 11 to 21 gigawatts (GW) and extended with the goal of 50 GW in 2040 [74]. Next to wind power, solar photovoltaic (PV) capacity is also experiencing rapid growth due to a well-supported subsidy scheme. In 2021, the installed solar PV capacity in the Netherlands rose from 10.9 GW to 14.4 GW and it is expected to almost double in the following three years, as can be seen in Figure 1.1 [87].

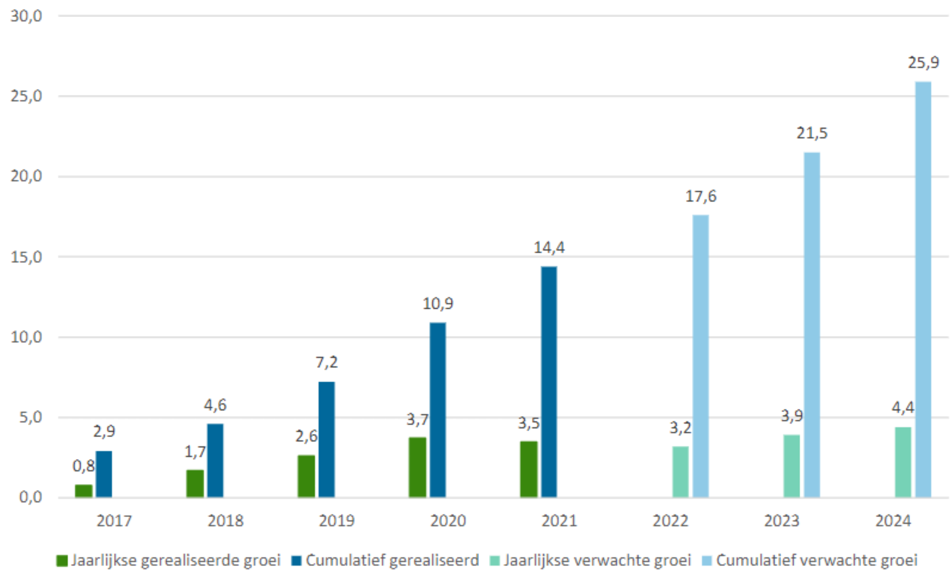

Figure 1.1: Installed solar PV capacity Netherlands 2017 - 2024

As the supply of electricity through wind and solar energy is heavily reliant on weather conditions and not all Dutch energy demand can switch to electricity, alternative low-carbon energy carriers will have to be adopted. One of the most promising potential carbon-free energy carriers is hydrogen, as it can be produced from water and electricity through the process of electrolysis. The promotion of this technology is progressively becoming part of political agendas and the Dutch government stimulates this movement with one of their objectives being an electrolysis capacity of 3 to 4 GW by 2030 [75]. To facilitate this goal, subsidies amounting to €783.5 million have been awarded to electrolysis projects. Once all the projects are completed, there will be an additional total electrolysis capacity of 1.150 GW [79]. These electrolytic hydrogen plants are intended to be fed entirely with renewable electricity, producing so-called green hydrogen.

When taking a closer look at these developments, a planning and coordination problem is found. So far, it is not sure whether the development of renewable electricity and electrolytic hydrogen production are aligned and, thus, if sufficient renewable electricity is available for electrolysis during the development phase of our new energy system. One of the reasons for this is the growing consensus that renewable electricity should first be used to electrify multiple sectors like industry, transportation and housing directly. Electrification entails converting a system or process to use electricity as its primary power source instead of, for example, gas. The reason for this is the energy loss of 30-40% during conversion to hydrogen [66, 133, 70]. In addition, research by Madeddu et al. [71] showed that 78% of energy demand in European industries is electrifiable with current technologies, while the addition of technologies currently under development could realise 99% electrification. As a result, the demand for renewable electricity is expecting significant growth, threatening the business case for electrolysers. Fossil fuel-based electricity could be utilised due to a shortage of renewable electricity, resulting in higher carbon emissions. On the other hand, electrolytic hydrogen production plants could run fewer operational hours, generating less profitability and possibly higher system costs [54, 34]. Moreover, uncertainty is found in developments regarding the demand for carbon-free hydrogen. National hydrogen demand projections are 75-270 PJ/year in 2040 and 100-1790 PJ/year in 2050 [16].

To conclude, the large-scale roll-out of electrolytic hydrogen production is accompanied by great uncertainty on both the supply and demand sides. It is unsure what the effect will be regarding cost- or carbon reduction. Secondly, and more importantly, there is little to no arithmetic foundation on how much electrolysis capacity is prudent for the future energy system in the Netherlands.

1.1.1 The hydrogen colour spectrum

The production of hydrogen knows many different routes, often labelled with a colour. A broad spectrum of colours has emerged over the past years, but for this research, four primary colours will be considered: grey, blue, green and yellow. Hydrogen produced with fossil fuels is labelled as grey hydrogen. This emits significant carbon emissions and accounts for 81% of current global hydrogen production. As 18% of global hydrogen is produced as a byproduct of chemical processes at refineries, currently around 1% of hydrogen production is blue, green or yellow [51]. Blue hydrogen is created by combining fossil-fuel-based production with carbon capture and utilisation or sequestration (CCU/CCS), avoiding a large portion of carbon emissions. Moreover, for yellow hydrogen, two different definitions are often used. The first refers to hydrogen production through electricity solely produced by solar power. The second, as used in the work of Liponi et al. [67], defines yellow hydrogen as hydrogen produced with electricity coming from the grid, of which the exact composition is unknown. The latter will be considered in this research. Lastly, there is green hydrogen, produced through electrolysers that are supplied only by renewable electricity and consequently emit nearly zero carbon emissions [92].

1.1.2 Roles of hydrogen in a low-carbon energy system

With the large-scale deployment of electrolytic hydrogen production, significant amounts of green hydrogen will be fed into the Dutch energy system. This hydrogen can serve multiple roles. The first and most evident role is substituting hydrogen from fossil fuels with green hydrogen. This entails substituting processes where hydrogen is used as feedstock, such as ammonia production. Secondly, hydrogen has the potential to substitute gas in processes where combustion is involved, being used as a fuel gas. Another prospective application of hydrogen is in mobility. Hydrogen-powered fuel cells could give a new impulse to road transportation and potentially also to aviation, shipping and all other sorts of mobility. Lastly, hydrogen can be used as an energy storage medium to mitigate the volatile nature of renewable energy sources. Electrolysis can be used to produce hydrogen during periods of low electricity consumption, not wasting valuable renewable electricity on curtailment[1]. By storing the hydrogen, it can later be converted back to electricity using

[1] Intentionally reducing renewable energy output by, for example, switching off windmills.

fuel cells or combustion engines when there is a combination of low renewable electricity supply and high demand. This method of converting electricity into a molecule-based gas carrier is also known as power-to-gas (P2G). Hydrogen can help reduce greenhouse gas emissions by replacing electricity generation based on fossil fuels like gas turbines. Storage deployment is critical for this last role of hydrogen to be successful. The Netherlands has excellent potential for underground hydrogen storage in salt caverns or depleted gas fields, but there is still little information available on the pace of these developments [132]. Uncertainty can thus be found in whether the development of large-scale green electrolytic hydrogen production and hydrogen storage are aligned, or one outpaces the other.

1.2 Literature review

As identified in the previous section, it is yet unsure what the exact role will be of the deployment of electrolytic hydrogen production in the Dutch energy system. To gain a better understanding of this problem, a literature review has to be conducted. With this, we will gain insights into the perspective literature has on the functioning of electrolysis in other subsystems and in relation to renewable electricity. By doing so, the exact knowledge gap can be identified. Lastly, similar studies into the future role of electrolytic hydrogen production in energy systems will be assessed on methodology and scoping choices to support the methodology for this work.

1.2.1 Literature review methodology

Google Scholar was used to collect literature for this review. Different search strings led to a total of 21 different articles. To ensure the literature review was relevant, only articles after 2020 have been selected for the first part of this review. However, the year 2017 was selected as the minimum when focusing on the approach of similar studies. An overview of the selected literature with reference and the most relevant conclusions can be found in Table 1.1. The articles reviewed for methodological purposes have been omitted from this table and do not belong to the 21 articles earlier.

Table 1.1: Overview of selected literature

ID	Title	Ref.	Relevant conclusions
1	Optimal hydrogen production in a wind-dominated zero-emission energy system	[137]	The use of hydrogen for grid-balancing is not favourable. This is due to the high costs and low efficiencies of round-trip conversion.
2	The importance of water electrolysis for our future energy system	[66]	The European electrolysis capacity target requires a significant amount of renewable electricity. This electricity could also be used to electrify industries directly. The deployment of electrolysers could help the wind and solar projects, on the other hand.
3	How flexible electricity demand stabilises wind and solar market values: The case of hydrogen electrolysers	[110]	Electrolysis projects create a better business case for wind and solar projects. The European market values will stabilise above 10 - 28 €/MWh and 21 - 35 €/MWh for solar and wind respectively.
4	Country-specific cost projections for renewable hydrogen production through off-grid electricity systems	[54]	Netherlands one of the most suitable countries for electrolytic hydrogen production with an estimate production cost of 1.8 €/kg in 2050. The demand for hydrogen will rise due to the electrification of other sectors. There is doubt that enough renewable electricity will be left for hydrogen production.
5	The Role of Green and Blue Hydrogen in the Energy Transition—A Technological and Geopolitical Perspective	[92]	Scaling of renewable electricity production might not be enough to fulfil the demand for electrolytic hydrogen production. Hydrogen could be used to fill this gap.
6	Green hydrogen: the crucial performance of electrolysers fed by variable and intermittent renewable electricity	[34]	Scaling of renewable electricity production might not be enough to fulfil the demand for electrolytic hydrogen production. Blue hydrogen should be adopted first.
7	Public Norms in Practices of Transitional Planning-The Case of Energy Transition in The Netherlands	[114]	Electrolysers will not always be able to use green electricity for their production. This could lead to fossil-based electricity being used, leading to higher carbon emissions.

Continued on next page

Table 1.1: Overview of selected literature (Continued)

8	Blue and green hydrogen energy to meet European Union decarbonisation objectives. An overview of perspectives and the current state of affairs	[62]	Scaling of renewable electricity production might not be enough to fulfil the demand for electrolytic hydrogen production. Blue hydrogen should be used to pave the way for green hydrogen. However, its contribution in the short term appears to be borderline due to the lack of projects on CCS that can be implemented before 2024
9	Economic and environmental analysis of hydrogen production when complementing renewable energy generation with grid electricity	[43]	Using grid electricity for hydrogen production significantly increases production rates and profitability. If this is done with small percentages, it does not affect the carbon emissions much.
10	The economics and the environmental benignity of different colours of hydrogen	[1]	Blue hydrogen production with CCS and green hydrogen production with grid electricity have substantially larger carbon emissions than green hydrogen with renewable electricity. They even approach emissions of grey hydrogen.
11	Green, Turquoise, Blue, or Grey? Environmentally friendly Hydrogen Production in Transforming Energy Systems	[39]	The main role of blue hydrogen will be to pave the way for green hydrogen.
12	The hydrogen economy: A pragmatic path forward	[70]	Renewable electricity should first be used to decarbonise other applications than producing electrolytic hydrogen. The opportunity costs are high when hydrogen is prioritised.
13	Potential and risks of hydrogen-based e-fuels in climate change mitigation	[133]	Hydrogen production must be prioritised for sectors where direct electrification is impossible.
14	Hydrogen and the decarbonisation of the energy system in Europe in 2050: A detailed model-based analysis	[119]	Hydrogen can play a role in absorbing, storing, and transporting most of the additional energy from renewable sources in a future where high binding targets are deployed for renewable energy supply
15	Hydrogen Production from Offshore Wind Parks: Current Situation and Future Perspectives	[8]	Hydrogen production with electrolysis can play a role in offering grid balancing purposes. Offshore production is less costly, while onshore production is more flexible.
16	Hydrogen generation by electrolysis and storage in salt caverns: Potentials, economics and systems aspects with regard to the German energy transition	[73]	Integration of electrolytic hydrogen production in the German energy systems with salt cavern storage. MILP optimisation focused on NPV maximisation. Hydrogen production through electrolysis combined with salt cavern storage will positively impact the energy system. Especially concerning peak loads and wind farm curtailment.
17	Design and evaluation of hydrogen electricity reconversion pathways in national energy systems using spatially and temporally resolved energy system optimisation	[138]	Integration of electrolytic hydrogen production in the German energy systems with salt cavern storage. MILP optimisation with cost minimisation and carbon emission calculations. Large-scale storage and reconversion of hydrogen combined with a hydrogen infrastructure can contribute to the electricity grid's expansion.
18	Optimal operation of a wind-electrolytic hydrogen storage system in the electricity/hydrogen markets	[142]	Profit maximisation of a short-term wind-electrolytic hydrogen storage system using MILP. Profits can be obtained by converting electricity into hydrogen.
19	Large-scale hydrogen production via water electrolysis: a techno-economic and environmental assessment	[125]	Costs and life-cycle carbon emissions minimisation with MILP. Water electrolysis that obtains low costs and emissions is only achievable at specific locations worldwide.
20	On the climate impacts of blue hydrogen production	[4]	Blue hydrogen is suitable for low-carbon energy systems if applied with high CO_2 capture rates and supplied with natural gas knowing a low-carbon supply chain. If these conditions are met, a carbon emission reduction of 80-90% is achievable compared to standard production with natural gas.
21	Blue hydrogen must be done properly	[99]	Blue hydrogen is suitable for low-carbon energy systems if applied with high CO_2 capture rates and supplied with natural gas knowing a low-carbon supply chain. The Netherlands has a suitable natural gas supply chain, reaching emissions below 0.5%.

1.2.2 Renewable electricity for electrolytic hydrogen production

One of the most essential points of consideration found in the literature is the mismatch between the scaling of renewable electricity production and electrolytic hydrogen production. According to research by Janssen et al. [54], the demand for renewable electricity will rise due to the electrification of other processes, raising the question of whether enough will be left for hydrogen production. Contrary to demand, it is rather the supply of renewable electricity that is the problem according to Furfari and Clerici [34] and Noussan et al. [92]. Their research concludes that the scaling of renewable electricity might not be enough to feed electrolytic hydrogen production. Blue hydrogen should be adopted first to fill the gap and act as a bridge towards a carbon-free future with hydrogen. Other research even states that the primary role of blue hydrogen will be to pave the way to a green hydrogen future [39]. This is also mentioned by Lagioia, Spinelli, and Amicarelli [62], who see blue hydrogen as the short-term decarbonisation option for hydrogen demand. Green hydrogen is expected to play a crucial role in the energy transition by 2030 but still needs time to develop prior to that point. Hydrogen production with CCUS can offer decarbonisation potential until 2030.

The absence of sufficient renewable electricity could lead to the use of fossil-based electricity from the grid, according to Salet [114], which could, in turn, lead to more significant carbon emissions than initially expected. Complementary to this result, the effect of using grid-originating electricity in electrolysis has been researched by Hurtubia and Sauma [43]. Their article states that by using 10% of grid electricity, the costs of hydrogen production significantly decrease, while it barely increases carbon emissions. Profitability and system costs are thus significantly affected by using grid electricity. However, when a minimum of 90% renewable electricity is not considered, grid electricity significantly increases carbon emissions. This production route and production with CCUS (blue hydrogen) both have substantially higher emissions than green hydrogen. Their emissions even approach those of grey hydrogen production [1]. This is opposed by Bauer et al. [4] and Pettersen et al. [99], According to their research, blue hydrogen can achieve significant greenhouse gas emissions if done correctly. This depends on three key requirements; (1) the entire natural gas supply chain, including production, processing, and transport, operates with minimum carbon intensity. This is already possible in several countries, amongst which the Netherlands with an emission rate generally below 0.5%, (2) the grid electricity utilised for CCS originates from a low-carbon source, (3) the CO_2 capture rates should be consistently deployed at rates higher than 90%, which is possible with current technologies. If these conditions are met, blue hydrogen can reduce carbon emission by 80-90% compared to direct production with natural gas.

1.2.3 Renewable electricity for decarbonisation

A critique on electrolysis that is commonly mentioned in the literature is that early in the transition, renewable electricity is better used to decarbonise existing applications directly. To illustrate an example by Lehner and Hart [66], the European electrolysis capacity target of 40 GW by 2030 would consume 160 TWh of electricity annually. This is a significant portion of the 515 TWh renewably generated electricity across Europe in 2018. This renewable electricity could also be used to directly electrify industries, leading to fewer losses due to conversion. Research by Ueckerdt et al. [133] and Mac Dowell et al. [70] stress that renewable electricity should first be used to decarbonise other applications connected to the electricity grid. The concept of opportunity costs is associated with the production of hydrogen from renewable electricity. Due to the conversion efficiencies, valuable low-carbon electricity is squandered when it could be used to electrify energy systems directly.

1.2.4 Role of electrolytic hydrogen production

Several articles in the literature have additionally researched the role of electrolytic hydrogen production in other subsystems, such as grid operation. Research into a cost-optimal zero-emission energy system for hydrogen production in the Netherlands showed that hydrogen is not favoured for grid-balancing purposes [2] [137]. This is due to the high costs and low efficiency of electricity-hydrogen-electricity conversion (± 30 %). However, Seck et al. [119] see a role for green hydrogen in absorbing, storing, and transporting most of the additional energy from renewable sources in a future where high binding targets are deployed for renewable energy supply. Another study on integrating hydrogen production into offshore wind power showcases the same role. Both onshore and offshore electrolytic hydrogen production can provide support in dealing with the fluctuations of variable renewable electricity. However, offshore production sees fewer transmission losses due to submarine pipelines instead of electrical cables. On the other hand, onshore hydrogen production gives more flexibility, as electricity can still be sold directly to the grid [8]. In addition, Lehner and Hart [66] and Ruhnau [110] see a role for electrolysers in creating a better business case for wind and solar projects. With the help of flexible hydrogen production, the market values for solar and wind increase. Due

[2] Storing electricity in the form of hydrogen to prevent imbalances in the electricity grid.

to the flexibility, the European market values will stabilise above 10 - 28 €/MWh and 21 - 35 €/MWh for solar and wind respectively.

1.2.5 Comparison of similar studies

By analysing methodologies applied in research of similar problems, we can better substantiate the methodology selected for this research. In this subsection, we will compare the objective of the methodology, decision variables, temporal resolution and other important assumptions or demarcations made. An overview of the findings from this analysis can be found in Table 1.2. First, the common practices are explained, after which the most salient points are addressed.

The overall most-used method is optimisation modelling and in particular linear programming, where the element being optimised is either a monetary factor, such as costs or profits, or emissions. As outputs, the studies primarily focus on system-level performance, such as costs and emissions. However, in some cases, the main output is determining the hydrogen production costs. Notably, meeting demand is thus often not considered a system element. In some studies, however, it is incorporated as a hard constraint. As a time step, hourly is most common due to data availability. Weather and energy demand profiles are generally available as hourly datasets, allowing this resolution. As a result of this hourly time step, the time horizon is often one year. The computational load of running for many years is often cited as a reason. A large experiment setup combined with running for multiple years leads to lengthy running times. Often, large experiments are preferred over longer time horizons.

Table 1.2: Approaches of similar studies

Ref.	Objective	Decision variables	Output	Time step	Horizon	Important assumptions
[137]	Multiple objective optimisation; minimisation of total annual costs and total annual CO2 emissions.	Investments in technologies and operation levels of technologies.	System costs and emissions.	Hourly	1 year	Copper plate and greenfield approaches. Hydrogen storage only in salt caverns.
[119]	Minimization of total costs.	Investment in various energy production technologies. Both for electricity and hydrogen.	Hydrogen demand and production mix.	3 times slices per day	2016-2050	Combination of three different models. The geographical resolution is the EU instead of one country.
[138]	Minimization of annual system costs.	Investments in the most cost-effective technologies for 5 different pathways.	System costs and emissions	Hourly	1 year (2050)	5 different pathways (scenarios). The geographical resolution is in Nort-west Germany. An important constraint is only using surplus electricity.
[73]	Maximization of NPV.	Investments in technologies and operation levels of technologies.	Comparison of levelized costs of hydrogen	Hourly	1 year (2025 and 2050)	The geographical resolution is in Germany. Considers microeconomic and macroeconomic perspectives. Hydrogen storage only in salt caverns.
[142]	Maximization of profits	Electricity-hydrogen conversion and selling to market.	Optimal system performance	Hourly	1 day	Stand-alone system coupled to energy markets, only powered by wind energy. Hydrogen is stored in a tank.
[125]	Multiple objective optimization; minimzation of total annual costs and total annual CO2 emissions	Investment in technologies and level of curtailment.	Hydrogen production costs and environmental burden	Hourly	1 year (2040)	Only considers production on islands, where autonomous generation is possible.

Different but important assumptions in the article by Weimann et al. [137] are the copper plate and greenfield approaches. With the first, transmission constraints are neglected and energy can flow freely through the system. With the second approach, simulations start without any installations already in place, proverbially on 'a green field'. A whole new set of investments must be performed for each run. Both these approaches have been adopted to show the desired configurations for the system at hand without being path-dependent on previous investments. Seck et al. [119] take differ from the other reviewed studies in two ways. Firstly, their modelling framework consists of a combination of three different models instead of using one model. Secondly, their work knows a time step of 3 times slices per day (day, night and peak) instead of the hourly time step mainly deployed in energy system optimisation studies. By doing so, they can optimise for several years while still maintaining computational efficiency. Moreover, Welder et al. [138] consider electrolysers only to start operation in times of surplus electricity. This is to explore if there is still a business case for these technologies with this configuration. Lastly, two other studies consider their system completely stand-alone and not connected through the grid or im- and exports [142, 125]. This is done to adequately demonstrate how the systems work when there is no outside interference.

1.3 Knowledge gap and research questions

A summary of the reviewed articles can be found in Table 1.3. This table displays the arguments that have achieved consensus and the topics that have received dissenting opinions. Through a review of these key conclusions and arguments, we can identify areas of research that have been overlooked or not thoroughly discussed but are essential for policymakers to consider in guiding the energy transition.

Table 1.3: Literature review summary

Topic	**Consensus**	**Dissent**
Hydrogen production technologies	(1) Blue hydrogen must be adopted rapidly and will serve as a bridging technology for green hydrogen. (2) Using grid-originated electricity for electrolysis significantly impacts its profitability and emissions.	Results on actual CO_2 emission reduction through the adoption of blue hydrogen differ.
Renewable electricity for electrolysis	(1) Renewable electricity will not be available in large enough quantities to support electrolysis. (2) Valuable renewable electricity should first be used to electrify industries directly	A disagreement in literature is found on whether the lack of renewable electricity is caused by a lack of supply or an increase in demand.
The role of electrolytic hydrogen production	Electrolytic hydrogen production supports the functioning of renewables.	A disagreement is found in the literature on whether hydrogen should be used to absorb the volatility of renewable energy sources.

First of all, there is a lack of knowledge as to what the exact role of hydrogen will be in the future energy system of the Netherlands. Articles share different conclusions about its role as a buffer for the electricity grid. In addition, no proper studies have been conducted about this role in the Dutch energy system. Gaining this information is of great importance, as it supports policy-makers and market parties in adapting their strategies to the future configuration of the energy system. For example, fewer electricity grid reinforcements must be carried out if a part of the electricity transportation or demand can be covered with hydrogen. This is also a societal concern, as these costs will eventually be traced back to the consumers.

Secondly, there is little quantisation regarding future electrolysis production capacity in the Netherlands. A consensus in literature has been found on the need for rapid adoption of blue hydrogen installations. However, the discussion on the amount of CCS installations required is left open. Over-investments could lead to companies being unable to recoup their investments, while under-investments lead to carbon emissions that could have been avoided. Even more significant, as it is not seen as a bridging technology, is a lack of insights about the capacity of (green) electrolytic hydrogen production. In the literature, research on electrolysis is generally focused on the potential for carbon emissions reduction, cost reduction, or the allocation of green hydrogen to be produced. The research fails to go one step further and discuss the quantity of electrolysis capacity required, especially in the Netherlands. Gaining insights into the effect specific quantities of installed electrolysis capacity have on the Dutch energy system is highly relevant for policy-making. These insights can not only support the shaping of instruments such as subsidies or regulations to promote or discourage electrolytic hydrogen production directly. They will also show the uncertainties that shape the required electrolysis capacity, as explained in Chapter 2.

Essentially, as research has not yet been conducted on the topic, a knowledge gap has been found in what exactly a *prudent* capacity for electrolytic hydrogen production is in the Netherlands. Prudent, by definition meaning 'careful in providing for the future' [17], is operationalised in different elements when it comes to electrolysis capacity:

1. A prudent production capacity for green electrolytic hydrogen ensures that under all scenarios, maximum impact on the security of supply of both hydrogen and electricity systems is guaranteed. This does not necessarily mean it will solve shortages of electricity or hydrogen in all future scenarios, but increasing the capacity will not reduce the unserved demand. Many other uncertain factors can cause a disturbance in the security of supply.

2. Overall system costs for the Dutch energy system are kept to a minimum. Overinvestments will lead to unnecessarily high spending, which could have been used to support the transition in other ways or lead to higher costs for consumers.

3. Within this budgetary limit, the potential for carbon reduction is exploited to the maximum. The underlying concept behind the possible transition to a hydrogen-based economy is the reduction of these emissions. For policymakers to explore whether it is worth focusing on green hydrogen, it is essential to highlight this potential correctly.

As emerged in the introduction and literature review, great uncertainty is involved in determining a prudent capacity. The objective of this research is not to eliminate these uncertainties but to offer policy-makers handles for dealing with them. Next to the proposed capacity at the end of this work, this allows self-direction as to what constitutes a good capacity based on the governments' understanding and expectations of uncertainties. Let's say policymakers know beforehand that future renewable energy policy will focus on promoting large-scale offshore solar PV parks. The implications of this decision for developing a prudent electrolysis capacity will be available through this work.

Hydrogen storage is a critical area of uncertainty for this study, along with uncertainties related to both demand and supply. Many articles discuss the role of hydrogen in future energy systems, where hydrogen storage is naturally added as a buffer. Waterstof Programma [136], TNO and EBN [132], and Netbeheer Nederland [85] all emphasise the importance of hydrogen storage for the development of electrolysers and functioning of the future energy system in the Netherlands. There is a general consensus that hydrogen storage is required for electrolysers to have a successful business case, as their operation will largely depend on the variability of renewable energy sources. However, no research has been found as to what extent this storage is decisive for the need for electrolysis capacity or until which storage-to-capacity ratio there is interaction regarding the prudent capacity. The last objective of this research is to gain insights into the extent to which hydrogen storage determines the potential for electrolytic hydrogen production capacity.

In addition, we will lay focus on gaining insights into this subject until 2040. This has been decided for two reasons: Literature shows that until 2030, green hydrogen cannot contribute significantly to energy systems, but blue hydrogen is expected to pave the way. Secondly, the most significant developments of offshore wind capacity will be until 2040, namely up to 50 GW. All in all, this adds up to the formulation of the following main research question and sub-questions:

What is the prudent production capacity of green electrolytic hydrogen in the Netherlands until 2040, while accounting for various uncertainties such as supply of renewable electricity and demand for carbon-free hydrogen?

SQ1 *What is, based on the availability of renewable electricity, the potential for production capacity of green electrolytic hydrogen in 2030?*

SQ2 *How does the prudent production capacity of green electrolytic hydrogen depend on key uncertainties in 2040?*

SQ3 *To what extent does large-scale hydrogen storage capacity determine the potential for electrolytic hydrogen production capacity?*

Hereafter, the interpretation and reasoning of every question are explained. Additionally, we will discuss the methodology of answering these questions and, if applicable, the format of the desired answer.

RQ - The main research question covers this research's core objective: the determination of a prudent green electrolytic hydrogen capacity in the Netherlands. This is, however, based on great ranges of uncertainty in most input variables, of which supply and demand are the most prominent. Instead of trying to take these uncertainties away from the hands of the policymakers, the objective is to gain insights into their behaviour and relation to the prudent capacity. This will be done by constructing a combined electricity and hydrogen market model, where the electrolysis capacity is considered the independent variable. By comparing and using the results from forecasting studies of the Dutch energy systems like IP2024 [86], II3050 [85], TNO's ADAPT/TRANSFORM [127] and more, we create an experiment design that will explore the realm of uncertainties in the future energy system. Ultimately, this design will help to create insights into how a prudent capacity relates to these uncertainties: Which elements are less uncertain and could already be incorporated into current policy? Which elements have a significant impact, are very uncertain or both and thus require additional consideration? Can current policies correctly handle uncertainties, or can necessary adjustments be identified? The scenarios will be conducted over two separate years, 2030 and 2040. A more in-depth explanation of this methodology will follow in Chapter 2.

SQ1 - The Netherlands and European Union have already shaped a significant part of their policies regarding renewable electricity and the use of hydrogen for 2030. This research question aims to explore these targets and test whether they can be justified. This will produce insights into whether we are on track to reaching these goals or whether additional steering is needed. On the one hand, this serves as a validation mechanism for the methodology. We will test if the reconstruction of other studies produces similar results in the base components, like production levels and emissions. On the other hand, it provides an arithmetic foundation for some of the current policy goals for which this is currently not publicly available. The key example is the goal of 3-4 GW of electrolysis capacity in 2030, of which there are no publications on strictly which numbers this goal is based. This first sub-question will provide an understanding of the validity of this objective. The methodology used for exploring the possibility of electrolytic hydrogen production by treating the system's maximum electrolysis capacity as unlimited. Doing so will give us insights into how much renewable electricity will still be available for electrolysis. Additionally, different capacities will be compared based on their effect on the system's output.

SQ2 - Towards 2040, uncertainty margins will grow, resulting in a more significant challenge for policymakers. This will logically impact the prudent electrolysis capacity and the formation of this answer. For this sub-question, large uncertainty ranges will be explored with the help of experiments and the mini-max regret approach (Chapter 2). Consequently, the analysis will provide an understanding of not only the highly influential parameters in the system but also those with the greatest level of uncertainty. These insights will guide policy-makers in their guidance of the energy transitions and allow for self-direction based on their understanding of these uncertainties. The data required for these scenarios will be obtained through a desk research of mostly grey literature. By aggregating this data, we can identify the ranges of uncertainty that have been reported. This methodology is further explained in Chapter 2.

SQ3 - Hydrogen storage is generally considered important for the development of electrolysers. However, for the last sub-question, the objective is to identify the extent to which this storage impacts the potential for electrolysis capacity. This will be done by measuring additional capacity potential and costs or emissions as a result of differences in storage capacities. Gaining these insights is highly relevant, as utilisation of (underground) storage is suitable for governmental intervention. Currently, this is an already occurring phenomenon with natural gas storage such as 'Bergermeer', where subsidies are deployed to increase its levels before winter falls [76]. A similar construction could lead to an increase in the development of hydrogen storage. By gaining insights into this extent of influence, policymakers can decide whether or not to stimulate or intervene in the market.

It is important to note that this regards the functioning of hydrogen storage as a mid-term or seasonal buffer for the energy system, not the dampening of day-to-day fluctuations in demand and supply. Existing pipelines will smoothen out these and will not require the full capacity range of a storage facility.

1.4 Report structure

In Chapter 2, the suitable modelling tool is chosen and the other research methods are explained. Next, Chapter 3 will give a detailed description of the system, leading to an overview of all the variables that compose the system. Subsequently, Chapter 4 will highlight how these variables and their relations have been used to construct a model. Based on the impact and uncertainty, an experiment design will then be composed in Chapter 5, of which the results will be given in Chapter 6. In the following chapters, these results will be discussed, concluded and reflected upon, thereby answering all three subquestions and the main research question.

Chapter 2

Methodology

2.1 Research approach

To investigate the production capacity of electrolytic hydrogen, two distinct, but highly intertwined subsystems must be studied: the electricity and hydrogen subsystems. Both these systems are socio-technical in nature and are still in development, being primarily guided by policy-making. The chosen research approach must therefore clarify what the effects of the institutional arrangement are and how interventions can (positively) impact the system. In addition, the development of these systems is accompanied by great uncertainties. The chosen research approach should offer functionalities for dealing with them. To fulfil these requirements, the modelling approach has been chosen as the research approach. This choice was based on several arguments:

Firstly, a research approach that gives insights into yet unknown relationships and interactions is required, as this research focuses on the evolution of systems until 2040. According to Edmonds et al. [21], models offer researchers the possibility to describe how mechanisms relate over time. As internal consistency between relations can be ensured with different setups in modelling, it makes it a suitable approach for developing scenarios. For this research, scenarios will have an essential role because it is a commonly used way to address uncertainties. Moreover, Epstein [28] also refers to modelling as a hands-on methodology for dealing with uncertainties. With modelling, huge ranges of parameters can be swept over a vast range of scenarios, identifying the most significant uncertainties, robustness zones and critical thresholds. This, in turn, allows us to simulate the system's reaction to possible interventions and gives policymakers the handles to deal with these uncertainties.

On the contrary, a limitation often mentioned in using models to deal with great uncertainty is that the quality of the assumptions largely determines the quality of the output. In some cases, it requires the modeller to make assumptions due to a lack of quality data. An inevitable consequence of these assumptions is, to a smaller or larger extent, the bias of the modeller. This concept is also known as the value-ladennes of assumptions. As mentioned by Kloprogge, Van der Sluijs, and Petersen [57], this effect can be reduced by collaboration with peers or by consultation with external reviewers, so that choices can be validated and data can be checked. During the course of this work, we will host several information sessions and give presentations to experts about the assumptions made and the data used. This allows us to validate the model on multiple occasions and ensure large biases are removed. In addition, uncertainty in data is also dealt with by not attempting to combat the uncertainties and producing a one-fits-all answer that is able to deal with all uncertainties in all scenarios. Instead, the goal is to acknowledge and embrace these uncertainties and explore their regions. By doing so, acceptable regions of answers can be found that are not heavily reliant on the modeller's assumption choices or quality of data.

2.1.1 Modelling framework

The modelling approach knows several interpretations that go into more detail on, for example, modelling activity, variable quantity or structure [139, 72]. To give more structure to the research, we implement a slightly modified version of the Modeling and Simulation (M&S) Life-cycle as defined by Verbraeck et al. [135]. This life-cycle consists of fives stages, of which a visualisation can be found in Figure 2.1:

Problem definition In this first step, which has already been performed in Chapter 1, the problem and requirements of the study are identified. This essentially entails the determination of system boundaries and Key Performance Indicators (KPIs).

Conceptual modelling For the purpose of creating a bridge between the modeller and the problem owner, a conceptual model needs to be created. A conceptual model is a higher-level abstraction of the system to be modelled. In the case of this research, the problem owner can be seen as the Dutch government. The conceptual model can be presented in a textual or graphical manner, or both.

Specification In this step, the conceptual model is translated into formal specification language, which is normally independent of the platform it will be implemented on in the next step For this research, the specification and implementation are combined. The tool that will be used, Linny-R, is already a formal language. This makes implementation a form of specification. Additionally, the required data is added to the model. From this step onwards, verification is constantly performed between each step, making the process iterative.

Implementation After the specified model is verified with the help of the conceptual model and both are aligned, the specified model is ready to be implemented. This entails the creation of a platform-specific model in the software. After the model is implemented, a separate verification is performed.

Experimentation The last phase consists of constructing the scenarios, running them through the actual model and analysing the results. Within this phase, the validation is performed to check whether the output behaviour matches the expected purpose of the study.

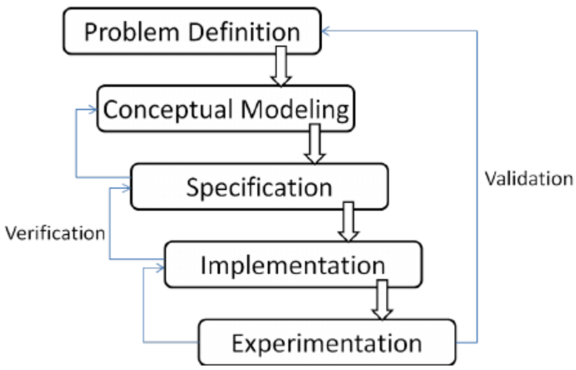

Figure 2.1: Modeling and Simulation Life-cycle [135]

2.2 Research methods

As mentioned in Section 1.3, research methods must be selected to properly answer the research (sub-)questions. In this research, we use a selection of three different research methods based on the different requirements as formulated in the sub-questions. First, we select a research method for the identification and quantification of the uncertainties regarding the role of large-scale electrolytic hydrogen production. Secondly, the appropriate modelling method and tool are selected, Lastly, we determine a method for the analysis of data based on dealing with great uncertainty.

2.2.1 Identification and quantification of the system and the uncertainties

In order to identify the uncertainties affecting the role of electrolytic hydrogen production in the Netherlands, we have to thoroughly study the Netherlands' combined electricity and hydrogen system. For this, we first have to gain knowledge on the production side of electricity and hydrogen regarding capacities, technical specifications, costs and carbon emissions. This entails a thorough research of grey literature on the evolution of the system until 2040. Secondly, future energy demand knows great uncertainty, both for electricity and hydrogen. Quantifying this demand into appropriate values, which can be used in the model to be implemented, therefore requires additional effort. The first step in this is to peruse reports and current literature on the future demand for carbon-free hydrogen and electricity. The second step is to aggregate this data into appropriate ranges of uncertainty. Moreover, the institutional arrangements influencing the system on both European and Dutch levels will be analysed. Ambitions and goals are identified by analysing strategy documents, directives, regulations and roadmaps. By doing so, estimations can be made on the expected levels of subsidies, limitations and possibilities for import and export and the effect on carbon pricing systems like the European Trading System (ETS).

2.2.2 Modelling tool

After determining the research approach, a decision must be made on the correct modelling tool. The modelling of energy systems, like the Dutch electricity and hydrogen systems, can be performed by an array of different tools. To select the most suitable tool, a small review has been conducted. A comprehensive review of modelling tools for energy and electricity systems, integrated with large shares of renewables, reviewed a total of 75 modelling tools [109]. The tools from this review, complemented with tools resulting from self-performed exploration, form the basis of which the selection takes place. The first selection was made based on three criteria. If these criteria are not met, the tool is excluded:

Geographical scope This study focuses on the energy systems in the Netherlands. It is, therefore, important that the coverage of the tool can be set to one nation or a specific area of the modeller's choice. Moreover, imports and export must be a possibility for commodity trading.

Commodities The tool must not only focus on electricity but also on other commodities. If a tool offers the possibility to include commodities as desired, it is included.

Accessibility The tool must be accessible with the resources available for this study. This includes open-source and free tools, along with tools offering a free academic licence.

After the first selection round, a total of 77 tools have been reduced to the 14 tools depicted in Table 2.1. Within this table, the tools are assessed on their purpose, temporal resolution, time horizon, and the offering of the following functionalities: H_2 storage, CO_2 emissions and CO_2 costs. Tools are generally designed to fulfil a specific task or purpose. We divided the tool into three different categories based on their purpose:

Operation decision support Tools designed for optimizing energy system's operation or dispatch, such as unit commitment. The temporal resolution and horizon of these models are often short, but geographically large scales are defined (national or European)

Investment decision support Tools designed for optimizing investment decisions in energy systems. As investments generally know longer cycles, the horizon often runs over a year or longer.

Scenario Tool designed for the investigation of scenarios. This is, for example, useful in exploring the impact of policy and interventions.

An important thing to note is that a tool is not necessarily bound to only one category, it is possible to fulfil all three purposes. A tool could, for example, be asked to generate different investment decision pathways for multiple scenarios.

Table 2.1: Overview of suitable modelling tools

Abbreviations used in this table: **Purpose:** S - Scenario, IDS - Investment decision support, ODS - operation decision support; **Temporal resolution:** UD - User Defined

Tool	Purpose	Temporal resolution	Horizon	H_2 storage	CO_2 emissions	CO_2 costs	Reference
Calliope	S, IDS, ODS	UD	UD	✓	✓	✓	[100]
EMLab-Generation	IDS	Yearly	2050	✓	✓	✓	[12]
EnergyPlan	S, IDS	Hourly	1 year	✓	✓	✓	[69]
ETM	S	Hourly, yearly	2050	✓	✓	✓	[102]
ETSAP-TIAM	S, IDS, ODS	Yearly	2100	×	✓	✓	[68]
HOMER	S, IDS, ODS	Minutes	Multi-year	✓	✓	✓	[64]
I-ELGAS	S, ODS	Hourly	UD	✓	×	✓	[58]
LIMES-EU	S, IDS, ODS	5 year, 10 year	2050	✓	✓	✓	[93]
Linny-R	S, IDS, ODS	UD	UD	✓	✓	✓	[7]
MESSAGEix	S, IDS	yearly	50-100+ years	✓	✓	✓	[42]
OEMOF (SOLPH)	S, IDS, ODS	UD	UD	✓	✓	✓	[40]
Renpass	S, ODS	Hourly	1 year	×	✓	✓	[140]
TEMOA	S	Yearly	UD	✓	✓	×	[41]
Urbs	S, IDS, ODS	UD (hourly)	UD (yearly)	✓	✓	✓	[18]

The appropriate tool for this research must meet specific requirements in order for it to be able to represent the proposed system. First, the *temporal resolution* must be, as a minimum, hourly. The underlying reason for this is the data format and method of measuring performance. Datasets on electricity and hydrogen demand, weather conditions and other required information are usually expressed in an hourly format. Carbon emissions and system costs, which will form the results of the model, are likewise often hourly outputs. This does not necessarily mean that ultimately our modelling time step will be hourly, we do, however, require this for verification and validation purposes as a minimum. Considering this requirement, EMLAB-Generation, ETSAP-TIAM, LIMES-EU, MESSAGEix and TEMOA are not selected for this study.

Secondly, as we focus on the development of hydrogen until 2040, the *horizon* of the modelling tool must be able to stretch until 2040. Considering that further research should be able to continue on the work created for this study, a horizon that stretches beyond this horizon is preferred. Considering this requirement, EnergyPlan and Renpass are not selected for this study.

Moreover, *hydrogen storage* is expected to play a significant role in future energy systems, including that of the Netherlands [51, 62, 34]. This research is exploratory in nature. Therefore the tool must be able to test the effects of hydrogen storage on the future role of hydrogen. Similar to this is the incorporation of *CO_2 emission* and *CO_2costs*. The main driver behind the energy transition as a whole is the reduction of carbon emissions. Without the ability to measure this, and the effect carbon pricing will have on the systems, the model will be biased. Only measuring the costs of new energy systems does not cover the trade-off policymakers face; decarbonisation versus system costs. Taking these requirements into account, I-ELGAS is additionally not selected for this study.

After considering the hard constraints of functionalities that need to be included in the tool, the next step is to take a closer look at the potential outputs and benefits that can be derived from the modelling. This entails taking a closer look at the function and the purpose of the model. Firstly, the model is required to optimize the hourly (if possible also daily) unit commitment problem and find the most cost-efficient generation scheme to simulate the Dutch energy markets properly. The second requirement for the tool is the capability to replicate or model investment decisions. This is necessary because our objective is to determine a prudent electrolysis capacity, which should be based on cost minimization in the first place. Moreover, conducting scenarios and experiments is a key functionality required for dealing with the ranges of uncertainty associated with the development of the energy system. This is also required to demonstrate the anticipated outcomes of various interventions to policy-makers. The Energy Transition Model (ETM) is one of the most versatile and detailed models for exploring energy scenarios [102]. The drawback this tool has for this research, however, is the absence of investment decisions in the simulation. In addition, it does not allow the modeller to run experiments with a range of input variables, often done in research that deals with a high level of uncertainty. We, therefore, decide not to use the ETM as our tool. HOMER (Hybrid

Optimization Model for Multiple Energy Resources) is often used to research renewable energy systems. For instance, a similar study into the future role of biomass constructed a model of the urban area of Amsterdam [55]. Despite being used in similar studies, HOMER is best utilized in microgrid settings where (entire) new renewable energy systems are designed [64]. As this project regards the nationwide, already partly existing, systems of the Netherlands, HOMER is not chosen as the modelling tool.

In essence, Calliope, Linny-R, OEMOF, and URBS are all well suited for modelling the proposed problem. When looking at the key functionalities needed for this research, all boxes are checked. However, we select Linny-R as the modelling tool for this thesis due to the additional advantages compared to the other tools. First and foremost is the intuitive and easy-to-understand graphical representation of Linny-R (Chapter 4). It can be described as a conceptual model that can simultaneously be used for optimization. Other tools often consist of lines of code, like the Python-based tool Calliope. As a result, policymakers or other relevant parties can not correctly understand what is at the heart of the model without first understanding how the coding works. With Linny-R, models can be created or changed while the conversation with the policymaker or system experts is still in progress. As the main modelling is not in code but with diagrams in the form of shapes and links, the policymaker can track and understand the development process. In contrast to other tools, where the other party needs to trust the modeller's claims about the content of the code, Linny-R allows for direct observation through the graphical representation, requiring only a brief explanation. This makes the model in Linny-R extremely transparent in communication towards relevant parties. On the one hand, this allows for model validation with experts without needing prior knowledge of the model. On the other hand, this allows for precise and transparent communication of the final model to policymakers, researchers and other experts. Secondly, Linny-R has a built-in feature that allows the modeller to switch the time step with only one click. This allows the modeller to quickly validate the model's behaviour and reduce the runtime if necessary. If, for example, hourly time steps take too much time to execute, the time step can easily be changed to 2 hours or even a full day. This approach will consolidate the data of 24 hours into a single time period.

Despite these advantages, Linny-R also knows its disadvantages compared to the other tools. First of all, it is still under development. Although having seen tremendous improvement over the years, the chance of bugs occurring is greater than with more established software like Calliope. Especially when using new features that have not been thoroughly tested yet. Additionally, attempting novel modelling constructions could require functionalities not yet available in the tool. This is, however, well-compensated by quick replies to bug reports due to accessible communication with the creator of the software. Overall, the advantages in terms of communication and transparency of modelling with Linny-R more than outweigh its drawbacks.

Linny-R rationale

To further understand the rationale of working with Linny-R, it is essential to take a closer look at the underlying mechanisms of the software. Linny-R is an executable graphical representation language for Mixed Integer Linear Programming (MILP) problems and is generally used for unit commitment problems (UC) and generation expansion planning (GEP). In essence, UC seeks to find the most cost-effective or profitable way to operate a set of generators that can satisfy the demand while satisfying other operational and engineering requirements. An important thing to understand is that this form of optimisation follows a neoclassical economic theory. The theory is based on the idea that individuals make rational decisions based on their preferences and the constraints they face and that markets are the most efficient way to allocate resources. All actors have access to the same knowledge and make rational decisions based on that knowledge. In addition, the experiments in Chapter 5 will be performed with complete foreknowledge. It should be noted that these conditions (almost) never occur in real-life situations. Not all market parties have access to equal amounts of information and are definitely not able to predict, for example, weather data a few months in advance. Rationality can not always be guaranteed as parties overlook certain information or have other underlying motives. This should be kept in mind when assessing the outputs of this research.

2.2.3 Dealing with uncertainty

One of the objectives of this research is to offer policy-makers handles for decision-making under uncertainty. To do so, methodologies have to be selected that; (1) still allow the creation of insights under multiple ranges of uncertainty; (2) will be able to quantify the degree to which the risk of uncertainty is dealt with.

The first methodology is covered by first gaining a proper overview of all the factors in the system and structuring them in such a way that uncertainties can be identified. This structuring of information is achieved by adopting the XLRM framework, shown in Figure 2.2. In the XLRM framework, the system is designed in a way that all uncertainties are considered as external factors. For instance, when there is uncertainty regarding specific relationships within the system, it is treated as an external factor. Within the framework, a model consists of attributes that include uncertainties, levers, and outcomes, which respectively refer to exogenous factors, policy levers, and performance metrics. Inside the model, the relationships of the system can be found. Using this framework, we thus get insights into the exact uncertainties that influence the system. The

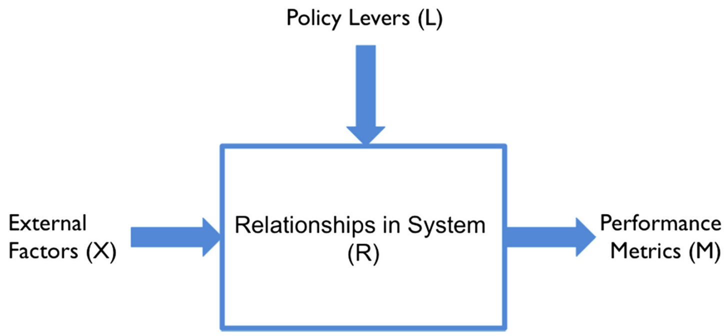

Figure 2.2: XLRM framework [61]

next step is to create an experiment design with these uncertainties. But before they can be translated into an experiment design, insights must be gained into their level of uncertainty and influence on the system. For this, an impact-uncertainty analysis will be conducted, as also done in the work of Ng and Ramasamy [88] and Kim-Soon et al. [56]. All input variables or external factors retrieved from the XLRM framework will be ranked first on their impact and second on their uncertainty. Impact, in this case, refers to the actual impact an external factor has on the value of the KPIs, These levels of impact will be achieved through a sensitivity analysis. Uncertainty, in this case, refers to the level of convergence of data retrieved from projections of the future Dutch energy system. The level of uncertainty will thus be achieved through the width of the range of projections. Once a ranking has been established, the input variables that compose the experiment design can be selected.

The mini-max regret methodology

For the quantification of dealing with risk, an additional methodology is required. One of these methods is the mini-max regret (MMR), a decision-making approach that seeks to minimize the maximum possible regret that could arise from a decision. It is often used in decision-making where there is a high degree of uncertainty. Regret refers to the difference between the actual outcome and the best possible outcome that could have been achieved if a different decision had been made. MMR aims to identify a decision that minimizes the maximum possible regret that could occur, regardless of the actual outcome that eventually happens, replicated through the experiment design. It is a conservative, risk-averse approach that seeks to protect the system against worst-case scenarios [105]. An example of this methodology can be found in Table 2.2. The table provides the costs associated with three different alternatives under two given scenarios. The concept of regret is defined here as the potential cost reduction that could have been achieved if a different alternative had been chosen. For the best alternative in a given scenario, this value is thus 0. To find the alternative with the lowest maximum regret, we calculate the maximum regret value for each alternative across all scenarios and select the one with the smallest value, in this case alternative 2.

Table 2.2: Mini-max regret example.

	Costs			**Regret**		
	Alt. 1	**Alt. 2**	**Alt. 3**	**Alt. 1**	**Alt. 2**	**Alt. 3**
Scenario 1	100	80	55	45	25	0
Scenario 2	95	70	105	25	0	35
			Max regret	45	25	35

MMR will be deployed on the KPIs, explained in the following subsection. By comparing the unaltered outcomes and the MMR outcomes of the modelling, we can gain insights into the differences in, for example, system costs and carbon emissions as a result of maximum risk aversion. This insight enables policymakers to determine their level of risk aversion regarding the stimulation of electrolysis in the Netherlands.

2.2.4 Measuring performance

To properly assess the scenario outcomes, key performance indicators (KPIs), referring to the 'M' in the XLRM framework, must be determined. We relate the KPIs to the different elements of a prudent capacity as defined in Chapter 1:

Electrolysis capacity This KPI resembles the core research performed in this work. After performing the experiments, the goal is to identify a prudent capacity in the Netherlands until 2040. This KPI can be achieved in two ways; considering the capacity as infinite during optimization to see the potential for electrolysis or incorporating an investment decision into Linny-R to optimize a prudent capacity. The electrolysis capacity is measured in GW.

Loss of load Preventing unserved demand, or loss of load, is extremely important in shaping energy policies in every country. As adding extra capacity should not jeopardize the security of supply, this KPI has been added. In addition, increasing the hydrogen storage buffer through additional electrolysis capacity could positively affect loss of load mitigation. Loss of load is measured in GWh.

System costs This KPI is included for two reasons. First, when optimizing, Linny-R seeks to minimize the overall system costs by deploying multiple different generation units. Since the system is thus evaluated based on the costs, it is important to incorporate this. Secondly, minimizing costs is a cornerstone of the Dutch (and European) energy policy. The recent energy crisis has shown us that maintaining affordable energy prices is extremely important for the system's functioning. Systems costs are measured in million euros (MEURO)

CO_2 emissions The reduction of carbon emissions is at the heart of the energy transition and one of the reasons for the deployment of electrolysers in the first place. This KPI is included to test whether these electrolysers have the desired effect on carbon reduction. CO_2 emissions are measured in kilo tonnes (kton).

Chapter 3

The Dutch electricity and hydrogen market: Conceptualisation

The Dutch electricity and hydrogen market are highly complex and interconnected systems. In this chapter, we will break down these systems to gain a better understanding of their functioning, corresponding to the conceptualisation phase in the M&S life-cycle. In the subsequent chapter, explanations will be provided on how this system is translated into an optimization model, showing all the detailed relations visually. Before an in-depth analysis can be conducted, we give a higher-level system abstraction. The conceptual overview of the system in Figure 3.1 shows the essential elements and flows in the system we consider.

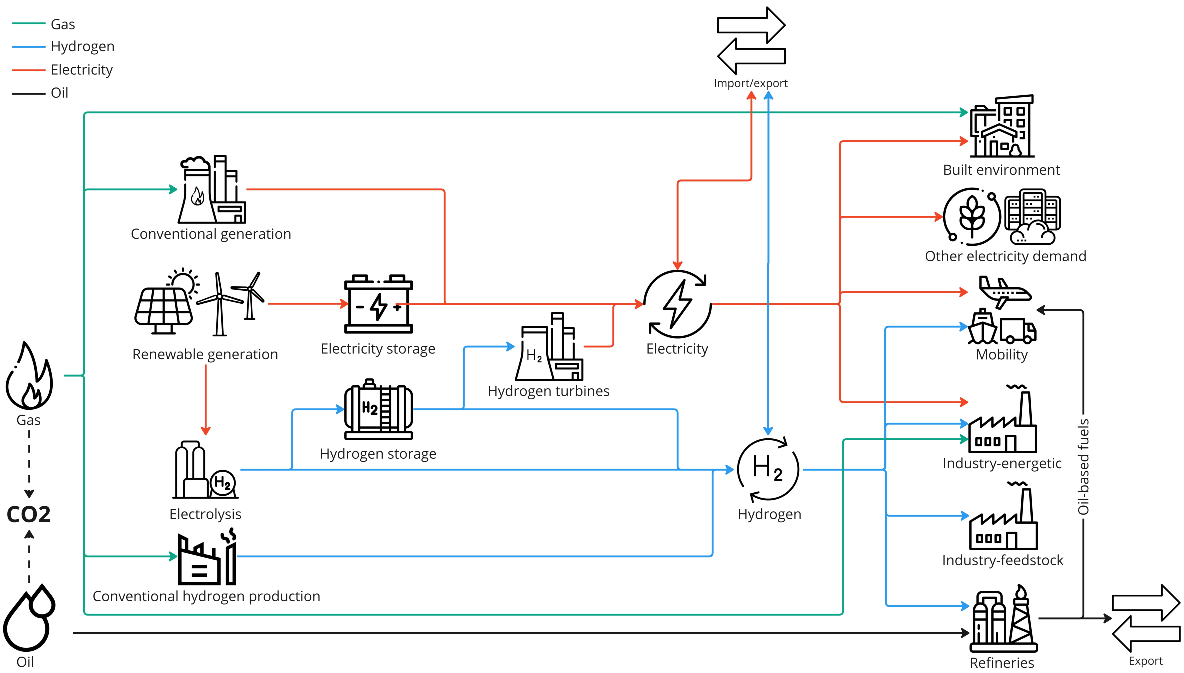

Figure 3.1: Conceptual overview of the system

This conceptual overview serves as a valuable tool for identifying several subsystems within the system. In the upcoming sections, we will delve into each subsystem in greater depth, providing a comprehensive understanding of its present state and expected evolution towards 2040. Additionally, we will define the system's boundaries, outline underlying assumptions, and highlight any significant uncertainties that may affect the modelling of the system. How these uncertainties are dealt with in constructing the model is additionally addressed. Furthermore, we make some assumptions to apply to the system in general and not only specific subsystems. These assumptions are:

- For the electricity and hydrogen systems, we assume no constraints in transmission and transportation. This approach is generally known as the 'copper plate' assumption. The reason for this is that the goal of this thesis is to find out a prudent capacity for electrolysis from a system perspective. The outcomes regarding the electrolysis capacity will be heavily reliant on how much the grid's limitations are considered. They will thus give a blurred image of the real potential for electrolysis. Moreover, modelling the Dutch electricity grid is a time-consuming task and does not fit in the timeframe available for this thesis. Lastly, grid simulations exponentially increase computational time, resulting in far less time available for experiment runs.

- Import and export are seen as black boxes and different countries are not considered in depth. Including this will shift away the attention from the core objective of this research and is too time-consuming.
- The processing of carbon captured from industrial processes is outside the scope of this research. For this reason, Carbon Capture and Utilization (CCU) will not be mentioned after this point. Every form of carbon capture is assumed to be Carbon Capture and Storage (CCS).
- One of the core modelling choices in this work is to determine the system's carbon emissions solely on the primary energy source consumption. Biomass and waste are assumed to have no carbon emissions. The reasoning behind this methodological choice is as follows: Calculating the individual emissions of carbon-emitting processes is always based on fossil fuel consumption and the consumption of possible carbon-based electricity. As we consider both the hydrogen and electricity systems, it ultimately all leads back to the consumption of fossil fuels for both the production of hydrogen and electricity. We are not concerned with the total gas consumption in the Netherlands or the EU, as this research aims to determine the additional effect of electrolysis capacity on carbon emissions. Hence, we can compare the gas consumption (read: carbon emissions) between scenarios or in comparison to a base scenario.

3.1 The Dutch electricity system

For years, the Dutch electricity system has been characterised by central generation and a one-sided electricity flow from the central producers to the consumers. As a result of the years of gas-stimulating agendas, this central generation was and still is primarily powered by conventional, mostly gas-fired, power plants [78]. One of the principal benefits of these gas-fired power plants and other conventional power plants like coal and nuclear is their controllable power generation. In times of low electricity demand, the generation can be scaled down, while in times of high demand, the generation can be scaled upwards. However, to meet the agreements written down in the climate agreement, this conventional, carbon-emitting generation will have to give way to renewable energy sources. By 2030, 70% of all electricity will come from renewable sources, like wind and solar PV [75]. As a result, the electricity supply will increasingly follow a weather and seasonal pattern, thus being more volatile. On the other side of the spectrum, growing demand is found due to the electrification of different sectors like industries, built environment and mobility. In this work, we chose to divide electricity generation into the categories conventional generation and renewable generation; both will be explained in the following subsections.

3.1.1 Conventional generation

Conventional power plant is the term generally used for an electricity-generating facility where fossil fuels are burned to create electricity with steam as an intermediary. However, for reasons of categorisation in this work, conventional generation refers to thermal power plants where any heat source is used to drive a generator that produces electricity. Conventional, or controllable, generation capacity will become increasingly important in the Dutch electricity system towards 2040. Due to its growing dependence on weather conditions, the Dutch electricity system requires carbon-neutral backup generation capacity to compensate for any shortfall in variable renewable energy generation. Especially in the case of prolonged periods with exceptionally low generation, the so-called "Dunkelflaute", the system needs to remain robust. For this, conventional generation remains of great importance and is therefore grouped into one category. The types of conventional generation, together with their expected installed capacity for 2030 and 2040, are displayed in Table 3.1.

It can be noted from the table that not all types of conventional generation capacity are included. Coal power plants have been left out, as all plants have to be taken out of operation by 2030 [106]. Moreover, geothermal energy production plants, although already widely deployed in the Netherlands, are not expected

Table 3.1: Conventional generation capacity [27, 86, 85]

Type	Current	2030	2040	Unit
Combined cycle gas turbine (CCGT)	1.2	9	4 - 7[1]	GW
Open cycle gas turbine (OCGT)	2.3	0.9	0	GW
Biomass	0.6	0.4	0 - 0.4[1,2]	GW
Waste incineration	0.2	0.3	0.3	GW
Nuclear	0.5	0.5	1.5	GW
Hydrogen turbine	0	0	9-11	GW

[1] Mostly with CCS.[2] -25% of base value.

to be used for electricity generation. This is due to the high cost-price of 300-400 €/MWh and the technical difficulty that, even with high geothermal temperatures, only an efficiency of 20% is within reach. Geothermal energy is better suited to fulfil the growing demand for heat in, for example, the built environment [141].

Another significant portion of conventional generation in the Netherlands stems from gas-fired combined heat and power (CHP) plants in greenhouse horticulture and industry. While the primary function of these installations is to generate heat, approximately 40% of their output is electricity. As there is very little information on the installed capacity of CHPs, we assume the generation to be an uncontrollable generation asset. This essentially means that electricity generation from CHPs follows a seasonal pattern, with higher generation in the winter.

Moreover, the Dutch electricity system knows a high degree of interconnection with neighbouring countries. A combined capacity of 9 GW is currently installed, amounting to more than half the gas generation capacity. This interconnection can become an essential option for flexibility in a future energy system with a high share of renewables. It is, however, not desirable because of the dependency on neighbouring countries, which has proven to be impactful in the most recent energy crisis.

The most significant uncertainty concerning conventional generation can thus be found in the different installed capacities of the technologies. The degree to which these capacities consist of hydrogen turbines significantly influences the demand for (green) hydrogen, especially during low VRES generation periods. In the experiment design, we deal with this uncertainty by formulation regions of installed capacity, especially for hydrogen turbines.

3.1.2 Renewable generation

The term renewable generation refers to variable renewable energy sources (VRES). In the Dutch energy systems, this is known as wind, onshore and offshore, and solar PV. Hydropower (< 0.03%) and other renewable energy sources like residual steam (< 0.4%) are not considered for this research [10]. As already mentioned, the electricity supply of VRES is highly dependent on weather conditions and thus volatile. When there is (close to) no wind and solar radiation, the remaining demand should be fulfilled by either controllable power and storage or absorbed with flexible demand. To reach a share of 70% electricity from VRES by 2030 written, the installed capacity of renewables will have to undergo significant growth. The ambitions regarding offshore solar wind for the Netherlands have already been set in concrete for both 2030 (21 GW) and 2040 (50GW) [74]. In contrast, the projections for the installed capacity of onshore wind and solar PV still vary. The climate agreement only states that by 2030, 35 TWh of renewable electricity should be generated onshore [75]. As also seen in Figure 1.1, solar PV is expected to experience a steep growth curve.

Solar PV and onshore wind are thus seen as the most significant uncertainties in this subsystem, as the goals for offshore wind are already determined for 2040. Their development has a great influence on the need for conventional generation, as more renewable generation implies that conventional generation or other flexibility is needed in fewer hours. In addition, it also determines the need for electrolysis capacity and storage, as more renewable generation capacity entails more hours of overshoot of renewable electricity.

3.1.3 Electrical energy storage

Electricity storage can play an essential role in dealing with the short-term volatility of VRES. There are many forms of electrical energy storage with large-scale lithium-ion batteries, supercapacitors, household batteries, flow batteries and batteries in electric vehicles. However, the assumption for this research is that the total installed electrical energy storage for the (high-level) Dutch electricity system is formed by large-scale lithium-ion batteries, household batteries and EV batteries. The reasoning behind this assumption is twofold. On the one hand, these batteries are expected to offer the most potential for short-term grid balancing and therefore have the most significant influence on the systems. On the other hand, increasing the types of storage within the model significantly increases the computational burden and, thus, runtime of the model. A lengthier runtime will lead to fewer experiments, which decreases the quality of the analysis. For this same reason, all batteries are assumed to have the same technical characteristics as a Lithium-Ion battery. Lastly, the batteries are assumed to have no ramping limitations.

The key assumptions and scoping choices made for the electricity subsystem:

- The electricity generation of CHPs is not influenced by the electricity demand and is thus seen as external.
- Electrical battery storage comprises large-scale lithium-ion, household, and EV batteries.
- Electrical battery storage has no ramping limitations.

3.2 The Dutch hydrogen system

The Dutch hydrogen system will experience drastic changes from this point till 2040. Until now, the hydrogen market consisted of a stable industrial demand and production, fed mainly with natural gas-based hydrogen. The emissions from the production of grey hydrogen currently account for 8% of national emissions with around 3 Mton of CO_2 a year [107]. Green hydrogen is expected to be the path to reduce these emissions drastically. In this section, we will describe what the hydrogen system currently looks like and the expectations for 2040.

3.2.1 Hydrogen production

As identified in Chapter 1, hydrogen production knows many different colours. Currently, grey hydrogen production in the Netherlands is dominated by steam methane reforming (SMR) technology [13]. In this process, natural gas reacts with steam to produce syngas, a mixture of hydrogen, carbon monoxide and carbon dioxide. SMR is often coupled with a water-gas shift reactor to obtain pure hydrogen from this mixture. This reactor extracts the carbon monoxide, leaving (almost) pure hydrogen. The most widely implemented technology for syngas production is auto thermal reforming (ATR), which also produces a mixture of hydrogen, carbon monoxide and carbon dioxide [13]. If coupled with a gas-water shift reaction like SMR, ATR can also produce hydrogen and is an excellent prospect for the future production of low-carbon hydrogen. The reason for this is the technically possible high capture rates of 98% or more if coupled with a carbon capture installation. In contrast, the capture rates of SMR with CCS peak around 70% [2]. Implementing CCS installations on either SMR or ATR significantly increases electricity consumption and, thus, hydrogen production costs. For example, CCS coupled to SMR induces additional electricity consumption of 0.9 GWh per kton of hydrogen [126].

Moreover, around 20% of the current hydrogen supply in the Netherlands stems from by-products of other chemical processes [11]. Catalytic reforming[1] and steam cracking[2] in refineries put out small proportions of hydrogen as a result of their primary function. However, we do not consider these processes for this system, as most of this hydrogen is used within the refineries, and export forms an insignificant part of the total supply (< 0.3%) [128]. Almost all production of hydrogen as a byproduct stems from the chlor-alkali process, the creation of chlorine and sodium hydroxide through electrolysis of sodium chloride (NaCl). In 2016, this accounted for a total of 24 PJ of hydrogen [116]. The last form of hydrogen production we consider in this research is gasification. This process transforms solids like biomass, coal, waste or heavy residues from refineries into, in this case, hydrogen gas. Only biomass gasification is expected to be deployed in the coming

[1] A chemical process to increase the octane rating in fuel mixtures

[2] A chemical process for breaking hydrocarbons into smaller (unsaturated) hydrocarbons

years [128]. Gasification of residues from refineries is left outside of the scope of this system, as this is mainly performed within the production plant itself and is not fed into the system.

We leave the production of hydrogen through pyrolysis of natural gas, also known as turquoise hydrogen, out of the scope of this system. This technology is still in development and is not expected to hit the ground in the coming 10+ years. We assume that by the time this technology reaches commercial readiness, electrolysis and reforming with CCS have already taken the market.

We decide to include these forms of conventional hydrogen production as they relate to the need for electrolysis capacity and hydrogen storage. These forms of hydrogen production are more stable and, to some extent, also controllable. Electrolysis, in contrast, is dependent on surpluses of VRES generation in the electricity system. The greater the steady influx of conventional hydrogen in the system, the less need for electrolytic hydrogen production accompanied by storage.

The most significant uncertainty arises in the capacity for hydrogen from reforming and the production of hydrogen as a by-product. In the experiment design, ranges based on different reports will be used to cope with this uncertainty

Electrolysis

In general, three different electrolysis technologies are considered the most well-developed and suited for large-scale production of hydrogen; Alkaline (AEL), Solid Oxide (SOEC) and Proton Exchange Membrane electrolysis (PEM).

Alkaline electrolysis is an already well-established and commercialised technology for the large-scale production of hydrogen. Holland Hydrogen 1, Shell's announced hydrogen production plant, will be based on a 200 MW alkaline stack [48]. It is characterized by low capital and operation and maintenance (O&M) costs. The downsides of this technology are the reduced efficiency with partial loading, being important for grid-balancing purposes and the relatively longer ramping times.

In contrast to alkaline electrolysis, PEM electrolysers are well-suited for short-term changes in load. They are characterized by their efficient production in partial loads and quick ramping times and are currently utilized for large-scale applications beyond 10 MW. However, the technology still experiences durability and deterioration issues.

Solid oxide has considerably higher efficiencies than other known electrolysis production methods. As a result, lower production costs are achievable due to less electricity consumption. However, it knows many disadvantages in high costs, long ramping times, durability and degradation of the stacks. Solid oxide can be useful for industrial applications operating at high temperatures. An overview of the characteristics of these technologies, based on four studies, is given in Table 3.2 [122, 36, 65, 118].

Table 3.2: Characteristics electrolysis technologies 3.2 [122, 36, 65, 118]

Characteristics	**AEL**	**PEM**	**SOEC**
Capital costs [€/kW]	426-1390	500-2140	2000-4800
Maintenance costs [% of investment/year]	2-3	3-5	n.a
Efficiency [%]	50-80	46-83	76-96
Warm start-up	1-5 min	<10s	15 min
Cold start-up [min]	5-50	0.5-20	60-600
Technology readiness level [-]	9	6-8	4-6

Based on the information from this small literature review and the current investment decision in the Netherlands being made based on AEL electrolysers, we consider the electrolysers in this research to be AEL electrolysers. In addition, the literature review showed that a cold start-up of an AEL can be performed within an hour. As the smallest time step to be considered in this research is one hour, we do not consider any start-up times or ramping rates.

Offshore or onshore electrolysis

The ambitious goals for offshore wind capacity require a vast area of the North Sea to be occupied with wind farms. As a result, these wind farms are placed at considerable distances from the Dutch shores. For example, the electricity generated in Nederwiek 3, the wind farm (currently) planned furthest from the shore, has to cover a total of 95 km (in a straight line) [80]. The transportation of the electricity to be produced by these wind farms invokes several issues. Offshore power-to-gas, close to the offshore wind farm, is increasingly mentioned as an option to prevent these issues, with a 1 MW pilot already planned in the Netherlands [98]. This has multiple reasons:

- The maximum capacity of an electric cable is around 2 GW, while the capacity of an offshore gas pipeline is 10-12 GW. This means that hydrogen transportation is less costly, as less cabling is required. Additionally, gas is much easier to store and the North Sea is filled with natural gas pipelines that could be repurposed for hydrogen transportation. The former brings additional benefits as fewer new coastal landings are required, which is seen as an advantage from an ecological and spatial planning point of view.

- Large volumes of electricity cannot always be fed into the electricity grid onshore at peak times. Transformation of this electricity provides a solution to the rising issue of net congestion [83].

- Lastly, transportation of electricity over such distances could lead to transmission losses up to 2.5% [94]. With future wind farms placed even further from shore, transportation in the form of hydrogen brings additional benefits as it has fewer transmission losses [108]. Opposing these benefits is the fact that the conversion of electricity into hydrogen knows a conversion loss of around 30% and the high fixed costs of building electrolysers offshore.

For these reasons, we make a distinction between onshore and offshore electrolysis. Although not considering any grid constraints, offshore electrolysis will have a specified portion of the offshore wind capacity allocated solely for the production of green hydrogen offshore. This is done to show to be able to show the difference dedicated wind parks have on the role of electrolysis in the Dutch energy system.

The level of installed electrolysis capacity is one of the KPIs of this study and, thus, of great importance. An investment function will be built into the model as we want to find a prudent capacity by optimising the system. With this function, a decision will be made based on the annuity of an electrolyser. This entails the capital expenditure costs of the electrolyser divided by its lifetime. If the optimization shows that one extra electrolyser will return the investment for that year, the extra investment will be made.

3.2.2 Hydrogen storage

Storage is essential in a future energy system where green hydrogen will be produced mainly by the electrolysis of VRES. With storage, short-term or seasonal shortages of both the hydrogen and possibly the electricity supply can be absorbed. Generally, hydrogen storage is divided into two kinds: above-ground hydrogen storage (AHS) and underground hydrogen storage (UHS). UHS is expected to support mid-term (dunkelflaute) and seasonal varieties in supply and demand, while AHS is expected to be used for short-term or even daily cycles. This research aims to identify the role of hydrogen storage for seasonal varieties and periods of shortages longer than a few hours. Hence, we leave above-ground hydrogen storage out of the scope of this research.

For underground storage, hydrogen is expected to be injected into either depleted natural gas fields, empty salt caverns or possibly also existing gas storage facilities. Storage in salt caverns is generally preferred over storage in depleted gas fields because of the proven maturity and examples in the UK and USA [143]. In addition, the Netherlands has excellent capacity potential with large caverns at Zuidwending, in the North of the Netherlands, where the first installations are already in development [45]. Between 2030 and 2050, around 60 caverns could be converted into 15 TWh of storage capacity. If this amount is insufficient to fulfil the demand for storage, storage capacity can be extended with depleted gas fields, which have a potential of over 200 TWh [132]. There is also the potential for offshore storage in depleted gas fields and salt caverns [131]. We assume UHS to be only filled with green hydrogen stemming from electrolysis. This is in line with the sustainability goals of the Netherlands and the EU and is also assumed in other studies involving underground hydrogen storage [132, 131].

As an assumption, we ignore the pressure-dependent filling rate of underground hydrogen storage. Underground hydrogen storage will consist of many caverns or gas fields in the future. These facilities must be filled separately, absorbing the pressure-dependent filling rate effects. Where one storage could be close to the maximum, another storage could just be starting to fill up.

The most significant uncertainty regarding underground hydrogen storage can be found in the amount of capacity that will come available. As insights into the relationship between this storage capacity and the prudent electrolysis capacity are also required to answer sub-question 3, we will treat the storage capacity as a policy lever for answering sub-question 3. In this way, we remove the uncertainty regarding the capacity and treat it as a variable determined by policymakers.

The key assumptions and scoping choices made for the hydrogen subsystem:

- Electrolysers are only fed with renewable electricity.
- Electrolysers do not have any ramping limitations.
- A portion of the offshore wind capacity is reserved for electrolysis.
- Underground hydrogen storage is solely filled with green hydrogen stemming from electrolysis. There are no injection rate curves based on filling degree.
- Hydrogen as a by-product from industrial processes is assumed to be constant and does not respond to changes in demand.
- Gasification of residual gasses from refineries is not separately included.

3.3 Energy demand

Transforming the Dutch energy system towards a low-carbon alternative requires not only the supply but also the demand for energy to change in multiple aspects. First of all, the composition, as well as the quantities, will take different shapes towards 2040. PBL [96] and Gasunie [35] created projections for the total electricity and hydrogen demand in 2030, depicted in Figure 3.2.

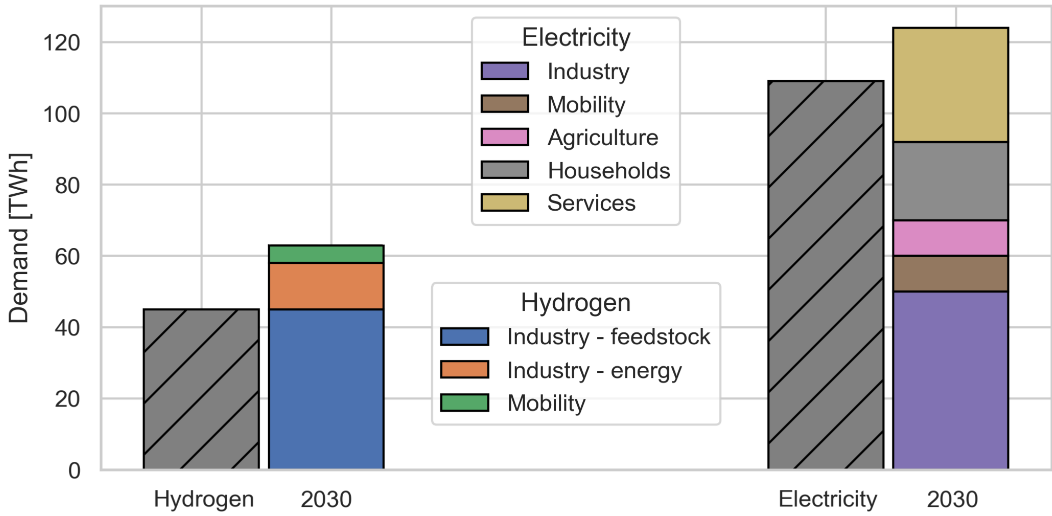

Figure 3.2: Demand per energy carrier 2030 [96, 35, Scenario 'midden']

By 2030, the demand for hydrogen (64 TWh) will be more than half the demand for electricity (124 TWh). What is remarkable is the difference in growth compared to 2022. The electricity demand is expected to grow from 109 to 123 TWh (+12.8%), while the hydrogen demand is expected to grow from 49 to 64 GWh (+30.6%) [10]. From 2030 to 2040, a considerably steeper growth in electricity is expected. TNO [127] reports a bandwidth of 144-189 TWh in 2030 and 210-330 TWh in 2040. This can be attributed to the extensive utilization of heat pumps in the built environment, the implementation of power-to-heat technology in the industry, and the surge in electrified transportation, all expected to take off after 2030.

Moreover, the graph shows no usage of hydrogen in households and services, also known as the built environment. Very few developments have emerged so far and numerous studies have reported little to no use of hydrogen in this sector [35, 11, 96]. For this reason, we assume no demand for hydrogen in the built environment until 2040.

The demand for energy is grouped into four main sectors; industry, mobility, built environment and grid-balancing. We consider the demand for hydrogen, electricity and natural gas for each sector. Natural gas demand is only accounted for if it can be replaced by either electricity or hydrogen or is used to produce hydrogen or electricity. Hereafter, we will discuss the different components that make up all of these demands and explain how we will deal with their uncertainty during the modelling.

3.3.1 Industry

As can be seen in Figure 3.2, a major part of the energy demand for both electricity and hydrogen is from the industry. Within the industry, hydrogen fulfils two main purposes; (1) a feedstock for the production of other commodities and (2) an energy carrier used to produce heat.

An overview of the current application of hydrogen in the Dutch industry, shown in Figure 3.3, clearly shows this distribution. The use of hydrogen as a feedstock consists of four elements: refineries, ammonia, methanol and other pure hydrogen use. Another energy carrier, like electricity, cannot replace hydrogen in this category. Therefore the only method of reducing carbon emissions is the replacement of grey hydrogen with green or blue hydrogen. The uncertainty in the use of hydrogen in ammonia, methanol and other uses is on the lower end of the spectrum. The usage of these feedstocks is not expected to undergo a lot of change in the transition towards a more sustainable industry. Therefore, we consider the combination of these three as one demand for hydrogen as a feedstock.

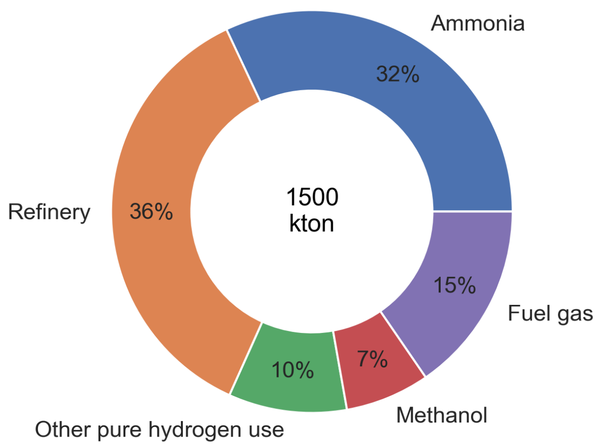

Figure 3.3: Hydrogen by application in industry [128]

As refineries play an integral part in the industrial sector, their functionalities are included in more detail. Refinery products are predominantly used in transportation, and transportation fuels form a large portion of the outputs (> 50%). The demand for products like diesel, gasoline and kerosene in other sectors determines the hydrogen demand for refineries [103]. If the demand for oil-based fuels in mobility declines, the demand for hydrogen in refineries declines with it. In addition, Dutch refineries largely produce fuels for export, of which the quantity is highly uncertain. We deal with this uncertainty by relating the export of oil-based fuels to domestic consumption. With this, we assume that the transition in mobility develops at an equal pace across Europe. This has been done by averaging export percentages over the past few years. As a result of this method, around 20% of production from refineries is destined for domestic use and subsequently, 80% is exported [9].

Meeting the demand for heat in future energy systems is expected to involve using hydrogen as an energy carrier. Currently, the primary method of generating heat for the industry is through the combustion of natural gas. However, by 2040, two possible replacements for natural gas combustion have emerged. First, in applications where lower temperatures are required, e-boilers or heat pumps based on electricity could be used instead of natural gas ovens. Second, the combustion of hydrogen can replace natural gas where the demand for temperatures is higher and heat pumps are insufficient [85]. An example of this is the glass industry. The pace at which these technologies are expected to develop knows high uncertainty, which we deal with as follows: First, the demand for industrial heat is grouped into one range of data, independent of the energy carrier used. As a result of this grouping, we can express the demand for hydrogen, electricity and gas in this domain as percentages of the total demand for industrial heat. The only two percentages that will increase towards 2040 are electricity and hydrogen consumption, as no new gas installations are built and they thus largely replace existing gas installations. Now, the error margin is reduced and predictions can be made by aggregating information from existing forecasting studies.

Furthermore, we consider some parts of the industry to be able to incorporate flexibility in two ways; through commodity switching and through scaling up and down of production. The first can be achieved by simultaneously operating e-boilers and hydrogen turbines so that they can switch commodities depending on the lowest costs. The second can be achieved by incorporating the possibility of stopping or instead extra start-up of (parts of) the industrial processes over time. In times of high electricity prices, parts of the industrial processes can be stopped and vice-versa.

3.3.2 Mobility

Fossil-based fuels have long held a dominant position in the mobility sector. Electricity and hydrogen, though, are expected to find their way into the market in the coming years. For this system, we consider four manners of transportation: road, air, water and rail. Figure 3.4 shows the different transportation methods along

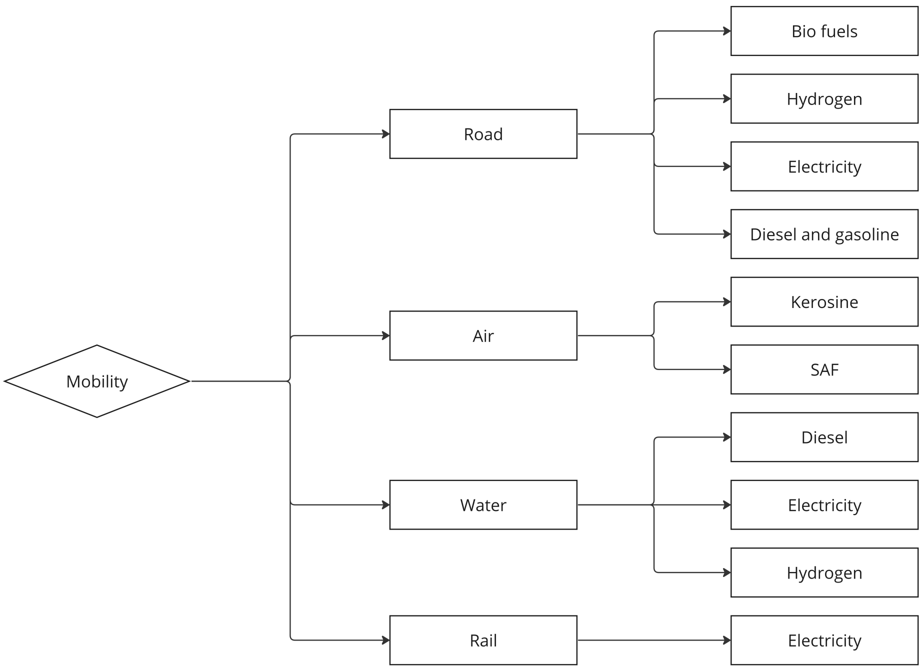

Figure 3.4: Types of energy demand in mobility

with the fuels that will be considered. In road transport, we consider passenger cars, public transportation by road as well as heavy-duty transportation trucks. Especially electric vehicles (EVs) have been finding their way into the market over recent years. However, in February 2023, the percentage for EV passenger cars and trucks remains at a marginal 6.1% and 0.3% of the total vehicle fleet in the Netherlands, respectively [82]. The road transportation landscape, thus, still holds significant potential for transformation. Hydrogen-powered vehicles, also known as fuel cell electric vehicles (FCEVs), are mostly expected to be found in heavy-duty road transportation [24]. Several documents and aspirations have been articulated on this matter, such as the ambition to have 100,000 heavy-duty trucks running on hydrogen in Europe by 2030, underwritten by a coalition of 62 parties [33].

For both road and air transportation, we assume an emergence of bio-fuels and Sustainable Aviation Fuels (SAF). The European Commission has issued the ReFuelEU Aviation initiative in the Fit for 55 package, which is based on a minimum of 5% SAF in 2030. This proposal significantly increases future demand for renewable hydrogen, as a significant part of this SAF will be based on hydrogen produced from electrolysis, also known as E-SAF [124].

The Netherlands is an essential hub for the bunkering of international water transport due to their extensive harbour area and refining capacity. Smaller domestic shipping is expected to change with the utilisation of electric or hybrid motors. On the other hand, international water transport faces a longer and more complex transition due to global legislation issues and difficulties with international waters [81]. For this reason, we assume only a small portion of the international water transport demand to electrify. Rail transportation is currently powered mainly by electricity. No major change technological changes are expected, and therefore, we assume the same electricity demand from now until 2040.

Uncertainty can predominantly be found in two elements in the mobility sector; the total demand for transportation and the level of adoption of hydrogen and electricity. Similar to industrial heat demand, we deal with this by grouping the total energy demand for mobility in the Netherlands into one factor. The demand is then satisfied by four types of fuel; hydrogen, electricity, oil-based fuels and other fuels, with bio-based fuels belonging to other fuels. In conducting the experiments, these types relate to each other based on substitution with oil-based fuels. When electricity, hydrogen or other demand grows, the demand for oil-based fuels declines and vice versa.

3.3.3 Built environment

The demand for energy in the built environment comprises many different components like spacial heating, lighting, tapwater, cooking and use of other appliances. As cooking is only a tiny fraction of the total demand (± 1 %) and all other functions are only to be powered by electricity, we assume that only the demand for spacial heating is substitutable between different energy carriers [112]. The electricity demand for other functionalities is assumed to not differ much over the coming years. As mentioned in Section 3.3, we also assume no use of hydrogen in the built environment. Hence, this demand for heating is met with either natural gas, electricity or heat networks with geothermal or residual heat. Towards 2040, the main focus is, therefore, on the degree of replacement of natural gas by electricity and heat networks. Gas is expected to be replaced by electricity mainly through the utilization of heat pumps. Other alternatives that could be used (in combination) are solar boilers, air conditioners and electrical (floor) heating.

Heat networks, also known as district heating systems, are essential to the Netherlands' carbon reduction policy. These networks supply heat to residential and commercial buildings through a network of insulated pipelines. The biggest long-term heat sources are geothermal, residual waste heat from the industry and greenhouse horticulture [97]. According to RVO [112], the number of households connected to heat networks will almost double from ±450,000 in 2021 to ±850,000 in 2030. The uncertainty for the development of electricity usage for heating the built environment is higher than for heat networks, as these numbers show.

3.3.4 Hydrogen for grid balancing

A potential key function of hydrogen storage in the future is as a buffer for the security of supply in the electricity network. In times of surplus of renewable electricity, which is expected to occur more frequently in the future, hydrogen storage can be filled by converting this electricity through electrolysis. If, towards 2040, there are extended periods without solar and wind production, the hydrogen can then be converted back to electricity with the help of gas turbines. As none of the reviewed studies incorporates fuel cells in scenarios for the future Dutch energy system, we only assume the use of hydrogen gas turbines. With these turbines, hydrogen storage acts as a giant 'battery' for the electricity grid. In the short term, this role can be fulfilled by electrical batteries, demand side response or other flexibility options. However, if the 'draughts' of energy persists for a more extended period (Dunkelflaute), greater quantities of energy are required and hydrogen might have to be used. Especially when considering the phasing out of natural gas.

The biggest drawback of this method is the massive energy losses due to the conversion of electricity. As seen in Table 3.2, electrolysers have an efficiency of around 70-80%. Although still partly in development, hydrogen-powered gas turbines are much less efficient, with an efficiency of around 52% (CCGT) [113]. As a result, a total round-trip efficiency of 30-50% is attained through electricity-hydrogen-electricity conversion. This can be seen as a waste of the valuable carbon-free electricity produced by renewables but may be crucial to ensure the security of supply in the future. For 2030, we assume no use of hydrogen gas turbines, as this is not mentioned in any of the reviewed scenarios. For 2040, both technologies will only be fed with green hydrogen coming from UHS. This is because the electricity supply should be carbon neutral by 2040 and, secondly, because direct usage of green hydrogen from electrolysers would imply that electricity is already available. This makes the use of hydrogen turbines and electrolysers in those times redundant.

The conversion rate of gas turbines and scaling of hydrogen turbines has a high degree of uncertainty. In addition, their influence on the system depends on the number of underground storage facilities and their production rates. If a storage facility cannot withdraw hydrogen quickly enough to feed all the gas turbines, adding more capacity will not have any effect.

Although not a part of the industry, we also consider the energy demand in the agricultural and ICT sectors. The purpose of this is to complete the total national demand for electricity. This demand in agriculture currently consists predominantly of electricity and is assumed to stay this way until 2040. Additionally, the volume of the demand is also assumed not to change, based on predictions of PBL [96] and Netbeheer Nederland [84]. Conversely, the ICT sector is expected to grow significantly due to the rise in data centres.
The key assumptions and scoping choices made for the energy demand subsystem:

- The demand for oil-based fuels for export is based on a percentage of domestic consumption.
- Industrial energy demand is constant over the year.
- There is no hydrogen consumption in the built environment.
- Fuel cells are not considered for the generation of electricity.
- Hydrogen turbines are not yet available in 2030.

3.4 Model scheme

Through the conceptualisation in the preceding subsections, we gained an understanding of all the elements in the system, their degree of uncertainty and how this uncertainty will be dealt with in the construction of the model and running of the experiments. This information allows the model scheme to be created by following the XLRM framework. The results can be found in Figure 3.5. This diagram shows in detail the level of uncertainty we face in modelling the future energy system. In our work, we consider three policy levers; installed electrolysis capacity, the number of underground hydrogen storages and carbon price. These variables are seen as the handles of the Dutch policy-makers. Their levels can be altered through legislation, subsidies or any other institutional arrangement. In the following chapter, we will clearly demonstrate how these variables relate to each other in the modelling performed.

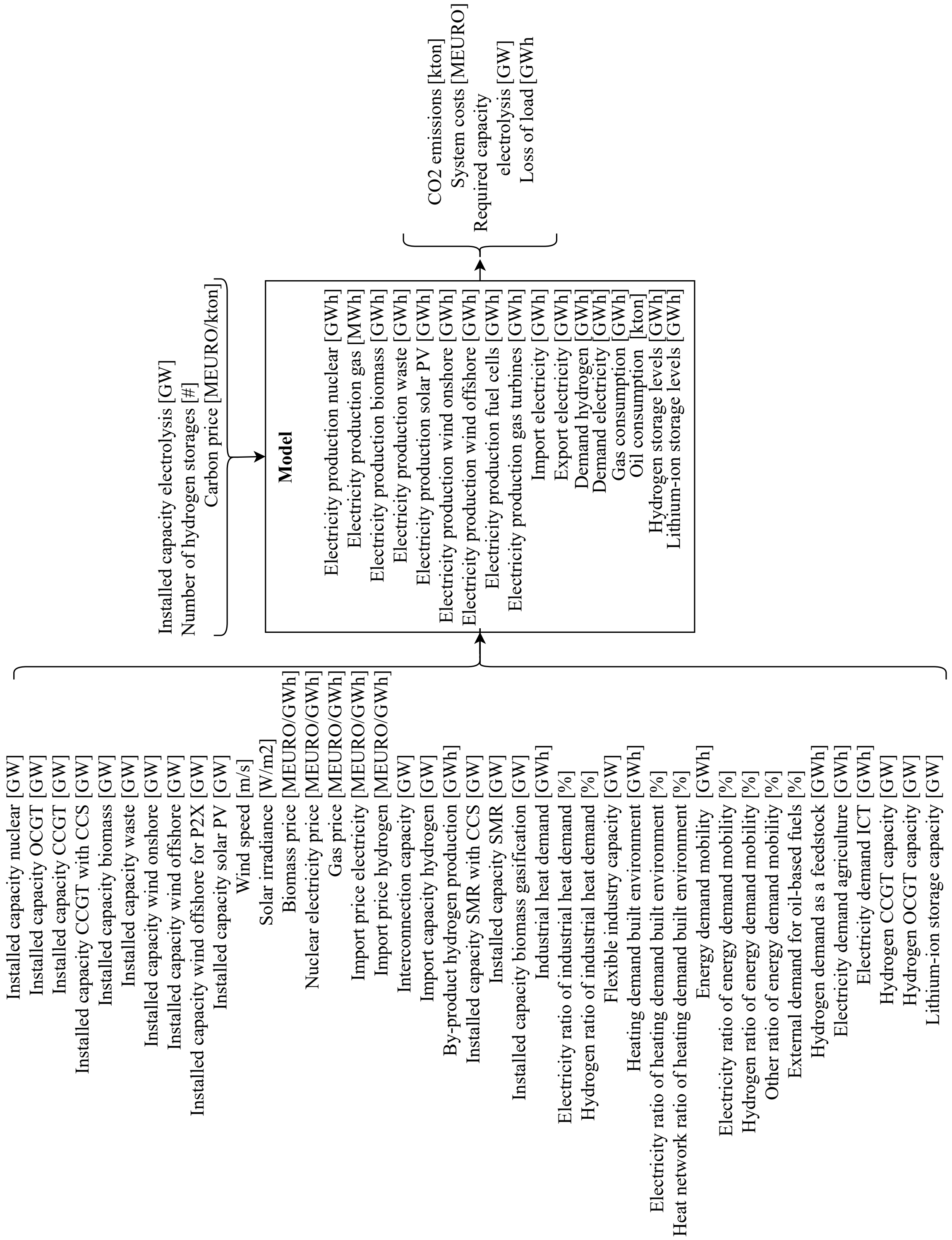

Figure 3.5: Model scheme

Chapter 4

Implementation in Linny-R

After giving a more detailed description of the system to be modelled in the previous chapter, we will now explain how this is translated into the actual model implementation in Linny-R. As Linny-R is characterised by its strong conceptual representation of relations, we will simultaneously use this chapter to show how the relations described in Chapter 3 are modelled.

4.1 Key concepts of Linny-R

Before a description of the model can be given, we must first describe the tool's basic (visual) components. This will contribute to a better understanding of the conceptual representation in Linny-R. It essentially exists of three main entities, products, processes and clusters. A more extensive description of Linny-R can be found on its web page [7].

- A product, representing something that can be consumed and/or produced by a process. This can be something tangible as electricity in our model, but also information, which is visualised as a 'data product'. Moreover, a 'stock 'is a product that acts as a storage, bound by an upper and lower bound (Figure 4.1).

- An item, representing a transformation of one or more products into one or more other products. An example in our model is the creation of the product hydrogen from the product electricity with the process of electrolysis (Figure 4.2.

- A cluster, a 'cosmetic' tool used to structure the model into subsystems. They do not influence the optimization but are solely used to make the model more understandable. Every process can only be part of one cluster, a product can be integrated into every cluster (Figure 4.3.

In addition, products and processes are connected through links. The links hold information about the flows between the entities, like the efficiency.

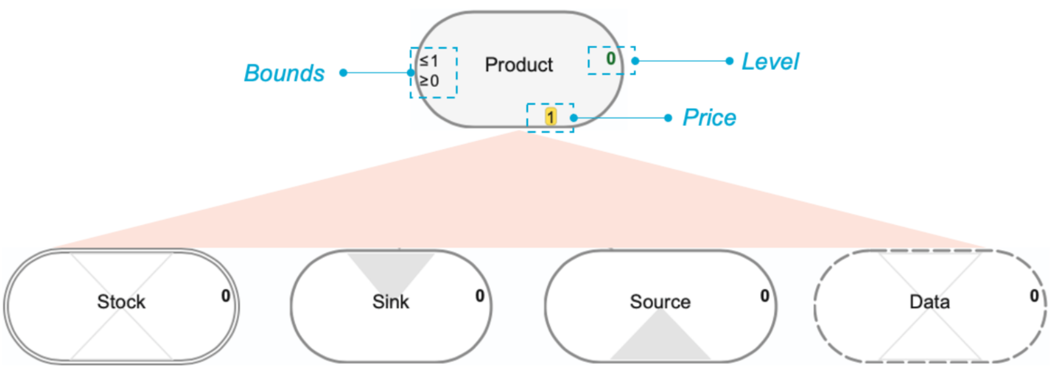

Figure 4.1: Linny-R - A default product and its four variants. Adopted from Groenewoud [38].

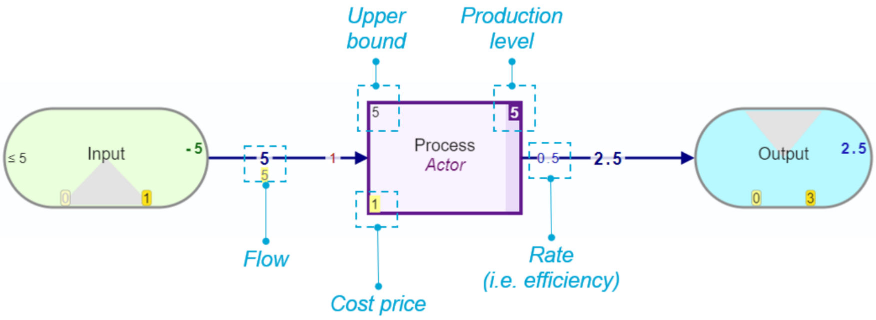

Figure 4.2: Linny-R - A process transforming an input product into an output product. Adopted from Groenewoud [38].

Figure 4.3: Linny-R - A cluster.

4.2 The model

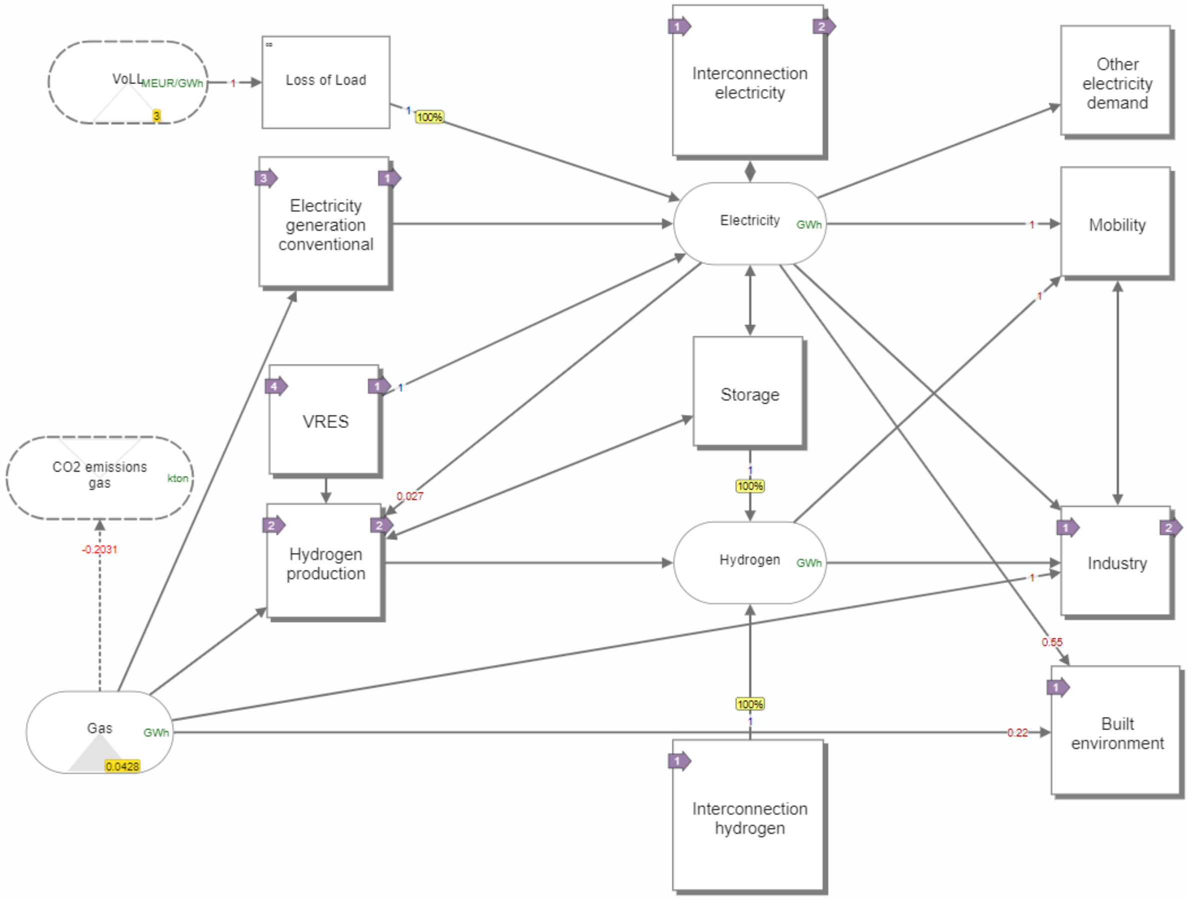

Figure 4.4: The top-level model.

For each model component, we will highlight the most essential modelling choices and, if necessary, clarify relationships. Figure 4.4 gives an overview of the top-level view of the model, showing the main clusters and relationships. On the left side, the generation clusters can be found, on the right side the demand with storage and interconnection in between. An important note to make is that the Loss of Load acts as a last-resort generation unit. If no other options are left, it will provide the system with electricity at an exorbitant price, the Value of Lost Load (VoLL), to prevent imbalances. Moreover, an arrow runs from the industry cluster to the mobility cluster. The reason for this is the oil-based fuels produced by the refineries in this cluster. More explanation will follow in subsection 4.2.4.

4.2.1 Electricity generation

Electricity generation, apart from the re-conversion of hydrogen, is divided into two clusters; electricity generation conventional and VRES, shown in Figures 4.5 and 4.6 respectively. The most important choices and assumptions are:

- The electricity output of CHP does not respond to changes in the model but is a fixed given output. There is no proper data available on the CHP capacity in the Netherlands and most of the assets are heat-driven instead of electricity-driven. Therefore, the CHP output corresponds to the hourly output of 2022 for all experiments.
- CCS installations, also for SMR, have a fixed capture rate of 70% (Figure Tab: A.1). The CO_2 emissions and thus additional costs for both the fuel and carbon price are reduced with this percentage in all experiments.
- A portion of the offshore wind capacity is reserved solely for electrolysis. As there is little to no information as to which fraction of these electrolysers will be placed offshore, the generated electricity will be fed into the same electrolysis as renewable electricity from other VRES through the product 'Renewable electricity for electrolysis'
- If renewable energy sources cannot feed their electricity into the system, they have the option to curtail their electricity.

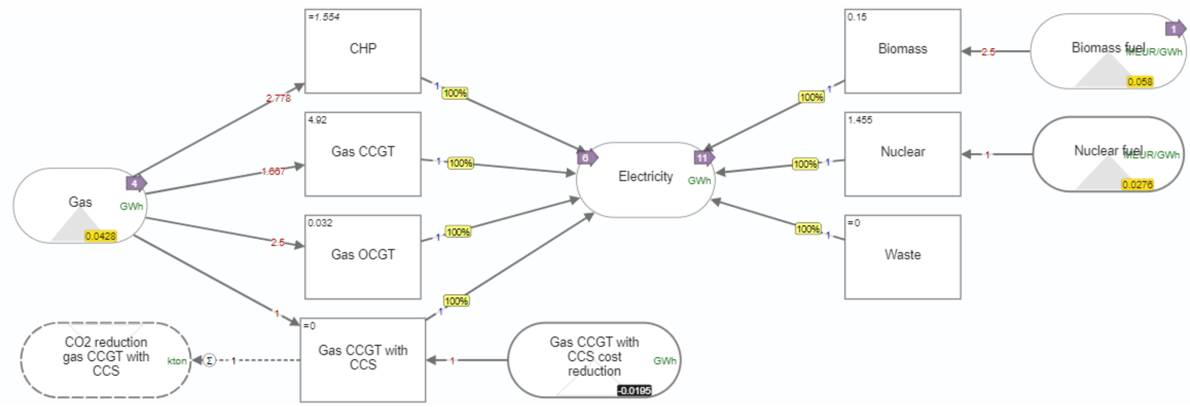

Figure 4.5: Electricity generation conventional cluster.

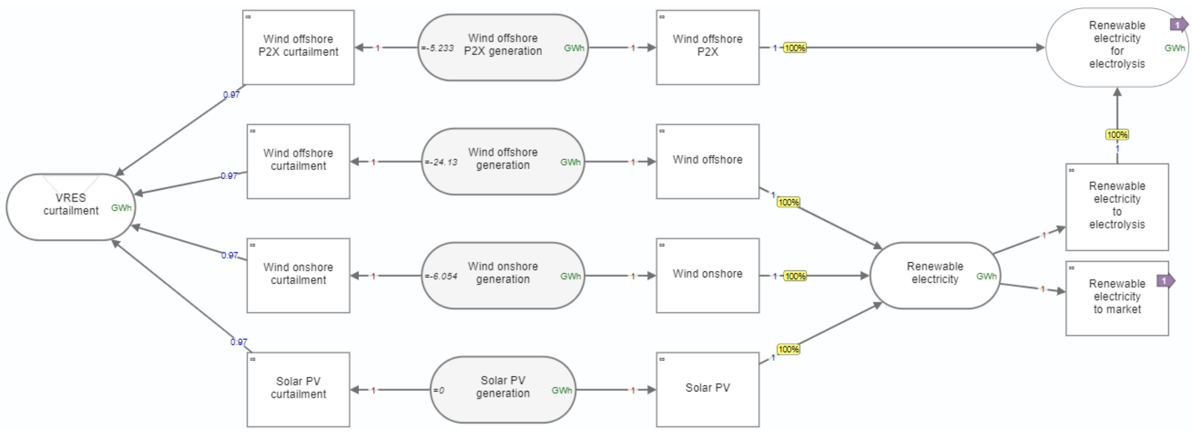

Figure 4.6: VRES cluster.

4.2.2 Hydrogen production

The Linny-R implementation of the hydrogen production cluster can be found in Figure 4.7. The following relevant modelling choices have been made:

- All the hydrogen produced in the system is collected in the product 'hydrogen', except for a fraction of green hydrogen that can be stored in UHS.
- Electrolysers are only fed with renewable electricity for this research. If there is no supply of renewable electricity, the demand for hydrogen needs to be fulfilled with other controllable production processes or with the help of storage.
- The industrial by-product of hydrogen is considered a fixed, unchanging supply of hydrogen. It does not react to changes in the model and remains at the same level in each time step throughout the entire run.
- The data-product 'Electrolysis: investment' contains the electrolyser investment function in the model. The investment is based on the annuity[1] of standard-sized 200 MW electrolyser stacks. The annuity of one standard stack is set at 4 MEURO, of which the calculation can be found in Table A.2. If 200 MW extra capacity reduces overall cost, Linny-R will invest.
- SMR and ATR are not considered separately but are grouped in one process. The reason for this is the lack of information regarding ATR; no projections could be retrieved from the literature.

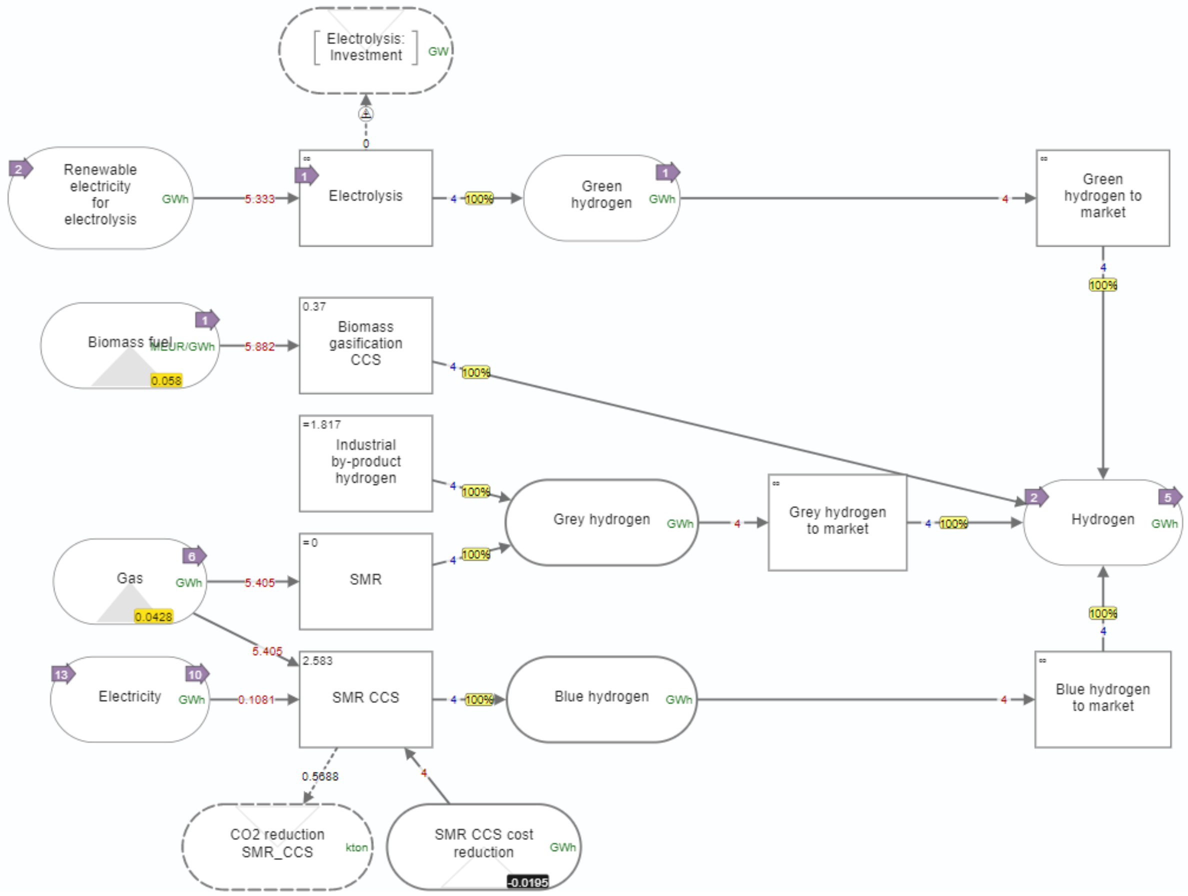

Figure 4.7: Hydrogen production cluster.

4.2.3 Storage and interconnection

In the model, we consider two main technologies for storage; batteries (LiOn) and underground hydrogen storage, collected in one cluster (Figure 4.8):

[1]The total investment costs divided by the lifetime

- Although the capacity combines different technologies such as EV-, household- and large-scale batteries, the product name is LiOn. To reduce the computational burden of the model, the different technologies have been grouped as one battery technology with the characteristics of a standard Lithium-ion battery. This entails a self-discharge rate or energy loss of 1% per day and a round-trip efficiency of 85%. Furthermore, we assume the charge rates of the batteries to be infinite, meaning the batteries can fully charge or discharge in one time step of 4 hours (subsection 4.3.1.

- The total UHS capacity comprises a given number of standard-sized storage units. These storages have the technical characteristics of salt caverns and each storage has a capacity of 200 GWh. The other characteristics can be found in Table A.1 This also means that the injection and withdrawal rates of the UHS increase with the number of storage units in the model.

- Underground hydrogen storage in salt caverns requires the compression of hydrogen. For this reason, the charge of UHS consumes an amount of electricity for every GWh of hydrogen stored. After this, the hydrogen can either be used to meet the electricity demand through hydrogen-powered OCGTs and CCGTs, or directly be used to meet the hydrogen demand.

- Lastly, the interconnection clusters are displayed in Figure 4.9. The Netherlands has multiple interconnectors with different neighbouring countries. However, modelling them separately into the system significantly increases the computational demand of the model. Therefore we have decided to aggregate all the interconnectors into one single process, represented by either import or export. Both these processes are linked by the data product 'Cable', which ensures only one of these processes can be used in each time step. Or in other words, the system cannot import and export electricity at the same time.

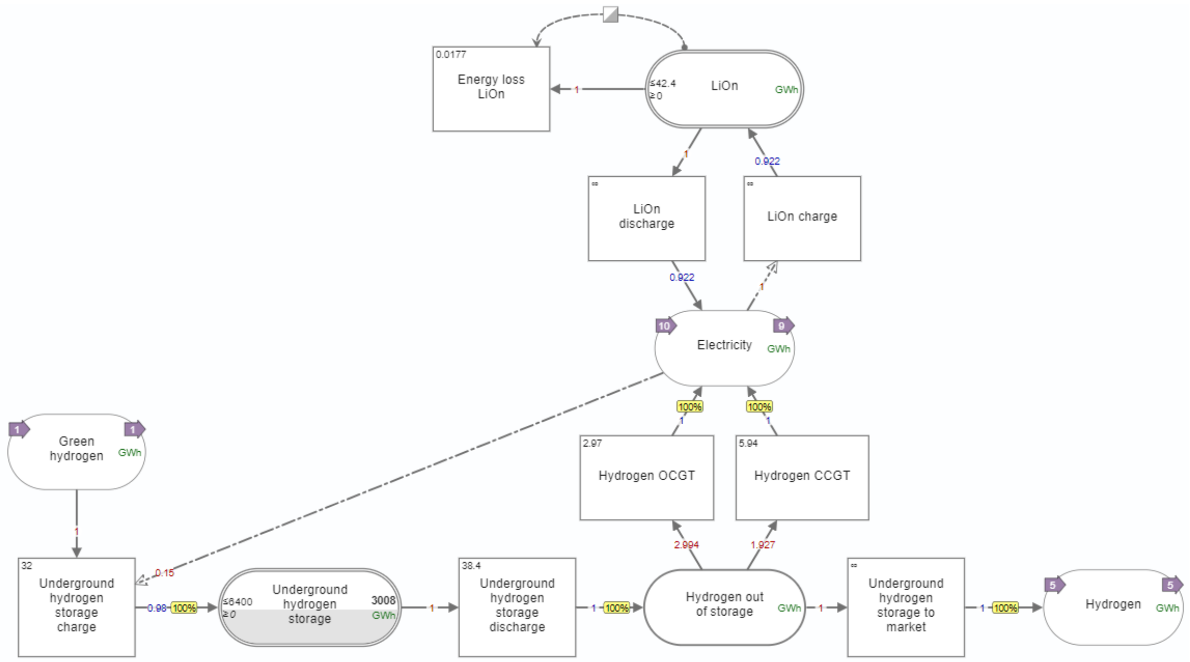

Figure 4.8: Storage cluster.

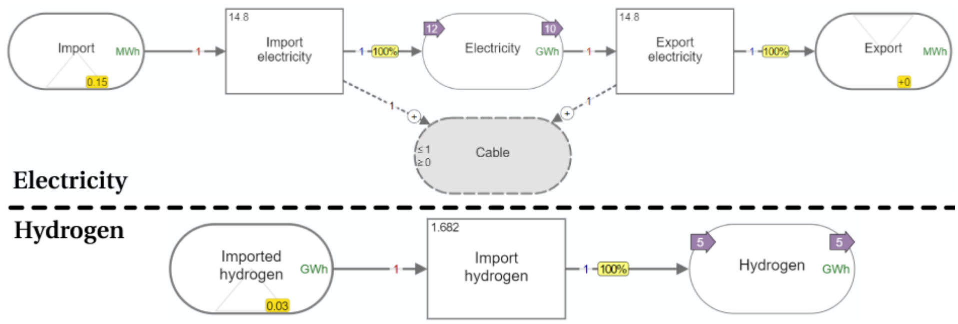

Figure 4.9: Interconnection clusters.

4.2.4 The energy demand clusters

The right-hand side of the top-level model is composed of the demand for energy. This demand is divided into different clusters, all discussed in this subsection.

Industry

Figure 4.10 gives the industry cluster, as implemented in Linny-R. In this cluster, the following modelling mechanisms have been implemented:

- The production level of refineries is based on the demand for oil-based fuels used in mobility. The demand for other products flowing from this process lies outside of the scope of this research. The decision behind this approach stems from the fact that oil-based fuels represent the largest proportion of the output, while there is a notable lack of data concerning the demand for other products resulting from refining. Additionally, this demand for oil-based fuels consists of domestic consumption and export. The demand for export is expressed as a ratio that can be defined by the user and is based on the level of domestic consumption.

- Typically, industrial processes operate consistently without adhering to daily patterns, as their production continues uninterrupted during the day and night. Despite utilizing other tools, such as the implementation of II3050 in ETM, no specific profile could be identified for industrial demand. To simulate the flat demand pattern, the demand for hydrogen as a feedstock and for industrial heat remains constant throughout the optimisation period, similar to the production of hydrogen as a by-product.

- The demand for industrial heat is composed of gas, electricity and hydrogen and is based upon substitution. Demand for gas-based heat is determined by subtracting the electricity- and hydrogen-based heat demand from the total industrial heat demand. This decision is made assuming that no further gas installations will be constructed and new installations will solely be powered by electricity or hydrogen, either as a new addition or to replace gas.

- Flexible capacity in the industry sector is incorporated in two ways; substitution between electricity and hydrogen and the adjustment of production levels, both upward and downward, following the same methodology as the II3050 report by Netbeheer Nederland [85]. The first involves creating two distinct processes, which the optimizer can select between. In this way, it will select the technology with the energy carrier being produced at the lowest costs for that time step. For the latter, a stock product has been built into the cluster to represent the possibility of stopping or, instead, extra start-up of (parts of) the industrial processes. When the electricity costs are high, electricity is drawn from the stock and vice-versa. However, the downside of this function is that downscale can only occur after production has first been increased for a (small) period. This limitation should be considered when assessing the results of industrial flexibility. The pool for the temporal flexibility shift is calibrated so that industries can only reduce or increase their process levels by one week. This has been done to prevent the model from reducing production for a (unrealistic) prolonged period. Lastly, because there was no data available for the distribution between these two methods, the total flexible capacity, in GW, is assumed to be evenly distributed.

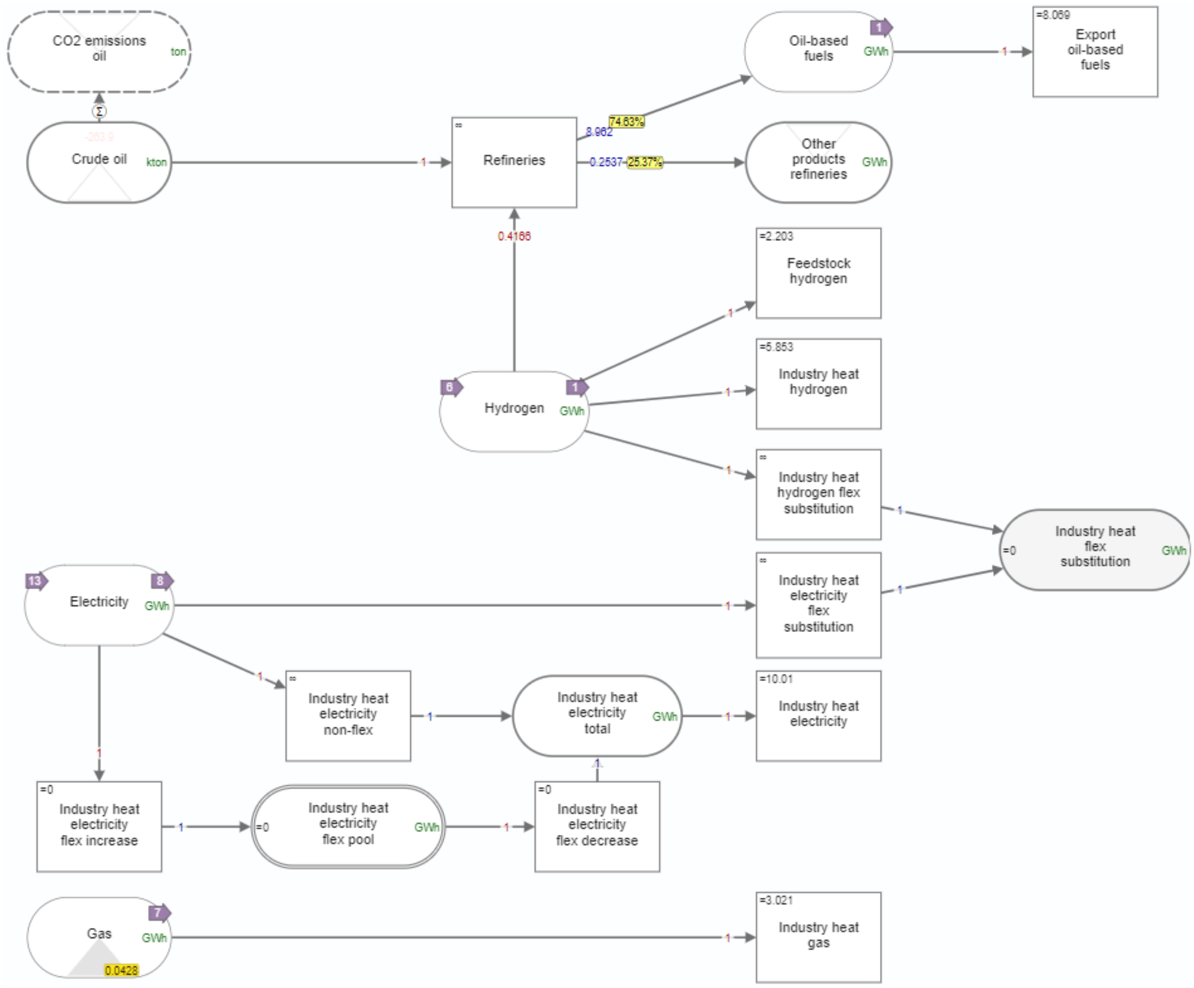

Figure 4.10: Industry cluster.

Built environment, mobility and other electricity demand

Although separate clusters in the Linny-R model, the clusters for energy demand in the built environment, mobility and other sectors have been grouped in Figure 4.11. The following mechanics have been implemented and choices have been made:

- Similar to industrial heat demand, the built environment and mobility demand have also been based on substitution between energy carriers. In the built environment, the demand for gas is achieved by subtracting the demand for electricity and heat networks from the total demand. This has been done under the same assumption as in the industry cluster. No new gas-powered buildings will be constructed and new buildings will solely be powered by electricity or heat, either as a new addition or to replace gas. New transportation vehicles powered by oil-based fuels, however, are still put on the market until 2035 [31]. For this reason, the demand for mobility is expressed in fractions, not in total demand. This way, the absolute value can still increase while losing market share compared to electricity and hydrogen, depending on the user's input value. For standardisation purposes, this substitution-based approach with fractions has also been used for other demands that can switch from energy carriers.

- The mobility demand for other fuels is used to determine the demand for oil-based fuels. So although having no visible relation with other products or processes, it should still be included in the model.

- The demand for built environment follows a daily, weekly and seasonal pattern derived from the Energy Transition Model [102]. Mobility, agriculture and ICT demand profiles are flat and do not have any variations between time steps. This assumption has been made due to a lack of data for these demand profiles.

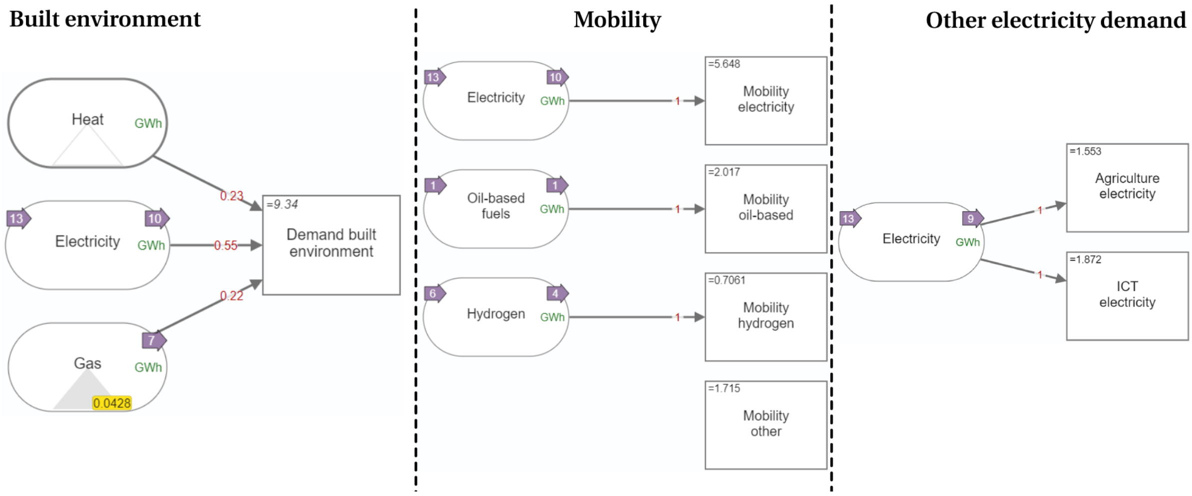

Figure 4.11: Built environment, Mobility and Other electricity demand clusters.

4.3 The base model settings

The research performed in this work focuses on two separate simulation years; 2030 and 2040. In this subsection, the implementation of the base scenario for both years is discussed. This includes base model settings such as time step and storage configurations, but also the KPIs' base outputs and the storage's behaviour.

4.3.1 Temporal resolution and horizon

When optimising with Linny-R, the temporal resolution (or time step) significantly impacts the run time and, thus, the number of experiments that can be conducted. For this reason, we should determine a time step with the lowest possible run time without changing the model's functioning and losing too much detail in the model's outputs. The minimum and most detailed time step for the model is 1 hour, as this aligns with the resolution of data sets used as inputs. To determine the time step for our experiments, we compare the outputs of different time steps with the output of a 1 hour time step. The scenarios used are similar to the base case only with slight changes, similar to those used for the sensitivity analysis, explained in subsubsection 4.4.1. The KPI values for the 1h time step are given in Table 4.1 and the comparison results are shown in Figure 4.12 and Figure 4.13.

Table 4.1: Time step validation - KPI values 1h time step.

KPI	2030	2040	Unit
Maximum electrolysis level	10.94	39.41	GW
Loss of load	9	64	GWh
System costs	8423	4504	MEURO
Carbon emissions	48716	23833	kton

In 2040, a substantial difference can predominantly be found in the loss of load and system costs when moving from a 4-hour to a 6-hour time step. The system costs drop by roughly 20%, which equals almost 1000 MEURO, while the loss of load almost disappears. The other two KPIs only show a significant change until a 12-hour time step. Based on the 2040 analysis, a 4-hour time step is thus acceptable. For the 2030 comparison, maximum electrolysis level, system costs and carbon emissions are not affected heavily until an 8-hour time step. However, the loss of load is highly affected by the change in resolution. A substantial difference of 65.6% in loss of load is found between the 1-hour time step and the 2- and 4-hour time steps. However, in absolute values, this difference is around 4 GWh, a difference we chose to accept for the 2040 comparison. The difference in percentages is thus highly determined by the maximum value in this particular scenario. However, the complete disappearance of the loss of load, which occurs after a resolution of 6 hours, is unacceptable. We thus choose to accept this difference until a 4-hour time step because of the substantial

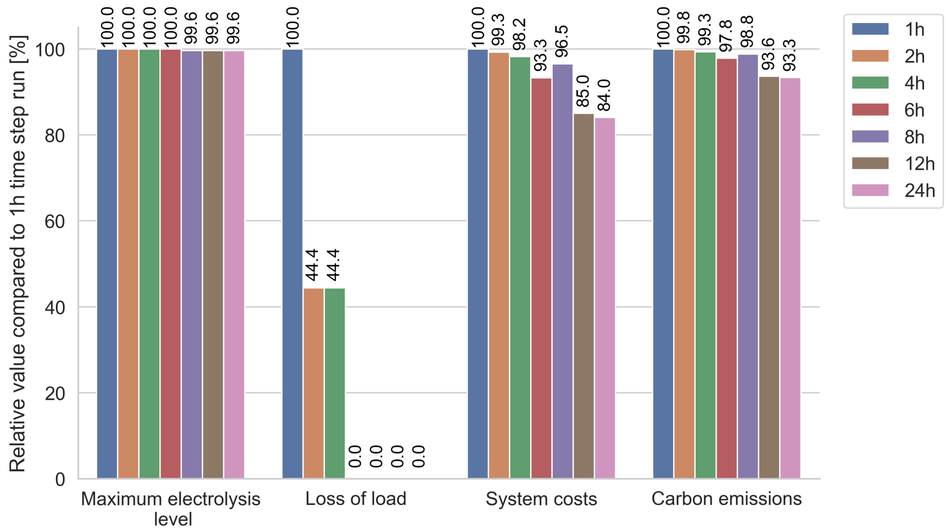

Figure 4.12: Time step validation - comparison for 2030.

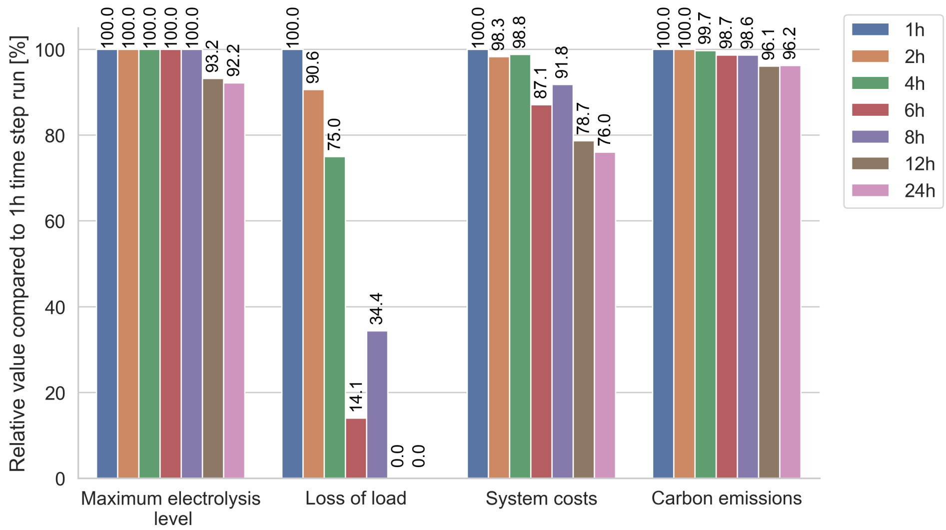

Figure 4.13: Time step validation - comparison for 2040.

computational benefits it brings. The optimization time of a single run decreases by approximately 800% when switching from a 1-hour to a 4-hour time step. This allows us to perform eight times the experiments and thus generate much more valuable data in the same period of time.

In addition, the increase in loss of load and system costs from a 6- to an 8-hour time step can be explained based on the solar PV generation cycle. If the time step is 8 hours, every second time step is between 8:00 and 16:00, as the optimization starts on January 1st at 00:00. For a significant portion of the year, excluding the days during and near the summer season, it thus effectively encompasses the entire solar cycle. As a result, the other two time steps receive no solar PV generation, resulting in higher losses of load and system costs For the 6-hour time step, the generation cycle is split over two time steps, spreading the generation more evenly.

Lastly, a common doubt in reducing the temporal resolution of optimization models is the change in functionality of a storage medium. In the case of this model, the batteries and underground hydrogen storage. The underground hydrogen storage should not show significant differences in behaviour, as it is expected to function predominantly as a seasonal or mid-term storage medium. On the other hand, batteries are expected to see a reduction in charging cycles, as they often operate within short-term volatility in the electricity market. Figure 4.14 showcases that the functional behaviour of the underground hydrogen storage is not affected much by the change in time step. Table 4.2 shows a decrease in the charge cycles of the batteries in the system. This is, however, acceptable, as the focus of this research is on electrolysis capacity and underground hydrogen storage, not the functionality of batteries and the change in charging cycles does not largely affect our KPIs.

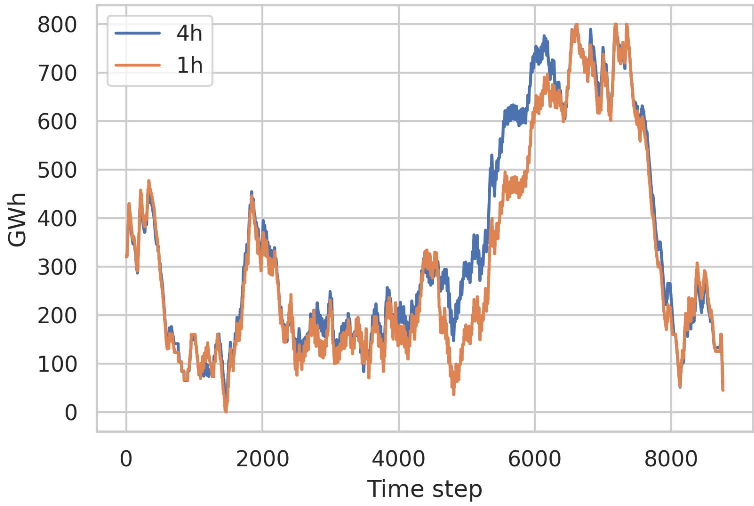

Figure 4.14: Time step validation - H_2 storage behaviour.

Table 4.2: Battery charge cycles.

Time step	**Charge cycles [#]**
1h	1018
4h	511

In total, each optimization will cover an entire year from January 1st 01:00 till December 31st 00:00, which consists of 2190 time steps of 4 hours. Next to the time step and optimization horizon, Linny-R lets its user define the block length and look-ahead, with the number of time steps as the unit. Block length refers to the number of consecutive time steps the optimizer optimizes in a single iteration. The longer the model's block length, the more information it has for its optimization, but the greater the computational demand. Secondly, the look-ahead represents the information of consecutive time steps available to the optimizer beyond the defined block length. However, a greater look-ahead also results in a greater computational burden, as with each iteration, more time steps need to be considered. For the optimizations in this work, the block length will cover the entire simulation (= 2190 time steps) and the look-ahead will be zero accordingly. This decision has been made for two reasons. First and foremost, certain factors within the model, such as demand in the built environment and industrial feedstock demand for hydrogen, can already be accurately estimated in great detail for the upcoming year. Patterns and quantities are already primarily known and the same goes for weather data. Although not able to predict on a daily or weekly basis, seasonal variations occur every year and reserves are built upon this basis. If we do not give this information to the model, it will act as if it has zero knowledge of what will happen for the rest of the year. Secondly, the ratio between block length and look-ahead could also have been, for example, 1095/1095. However, while having exactly the same information available, the model has to optimize while considering 2190 time steps twice with this method. As a result, the run time will significantly increase while not gaining any advantages in optimization.

4.3.2 Storage constraints

Near the end of a single run, Linny-R automatically empties any products or goods left inside a stock. The objective function is the minimization of costs, and in this way, it reduces any costs made with generation. The single-year runs for this study start on the 1st of January and end on the 31st of December. Generally, gas and other energy reserves are not allowed to reach a level of zero at this period in time. If we look closer at the Dutch gas reserves since 2010, the fill rates have only been lower than 65% on one occasion (in 2021) [89]. As empty hydrogen storage in the last time step is unrealistic, a constraint must be added. This constraint has been determined by stimulating 10 consecutive weather years and measuring the storage fill rate on the last step of each year for 2030 and 2040. The results are in Appendix C. The minimum fill rates at the last time step of 2030 and 2040 resulting from this method are 41% and 47%, respectively.

Furthermore, large-scale energy storages generally have a minimum filling rate for the system to be robust against a Dunkelflaute or other disruptions. However, in these situations, the storage must be able to reduce its filling rate to a level (close to) zero to cope with the disruptions. To simulate this behaviour, a constraint is added to the model that commands the storage to be filled back to 20% of its capacity every two weeks, based on the graph of NOS [89]. Between these control points, the model is free to empty its storage.

4.3.3 Weather years

In an energy system with a high penetration degree of VRES, the weather is one of the most important but simultaneously uncertain parameters. As predicting weather data for 2030 and 2040 is impossible, we use historical data obtained from renewables.ninja [101, 123]. This database consists of hourly production factors for solar PV and wind offshore and offshore from 1985 until 2019. We decided to optimize with two weather years; a normal year and a year representing a dunkelflaute. The first is to gain insight into the 'normal' functioning of the system, and the second is to test its robustness against a drought of renewable electricity. We assume 2019 to be the normal year as it is the most recent and does not show prolonged periods without sun or wind. The weather representing the dunkelflaute is 1997. At the end of January, it knows a prolonged period without wind production, as shown in Figure 4.15.

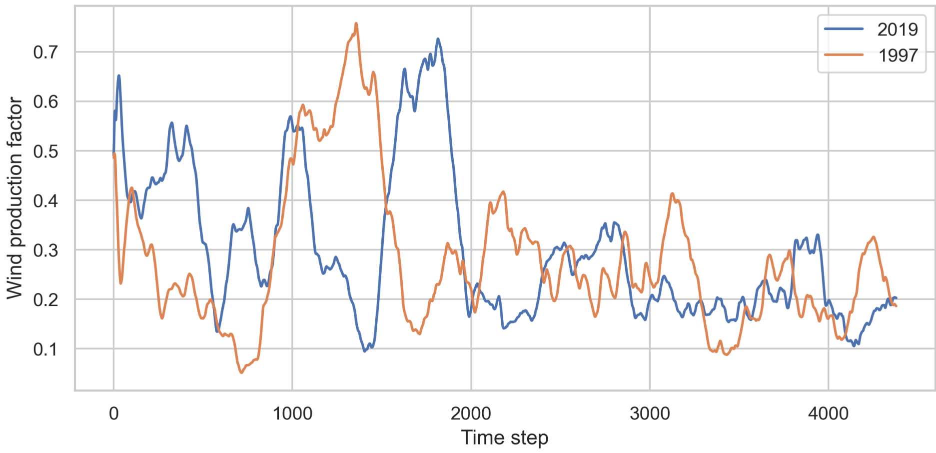

Figure 4.15: Weekly average wind production factors 1997 and 2019, first half year.

4.3.4 Base scenarios 2030 and 2040

To establish a benchmark for comparing outcomes and as a basis for conducting verification and validation analysis, two base scenarios are constructed: one for 2030 and another for 2040. The input values for these scenarios can be found in Table A.3 and A.4. The model settings described in previous subsections have been adopted for both scenarios and are depicted in Table 4.3. For both the base scenarios, the weather year 2019 was used, representing an average weather year. Additionally, as it is the primary independent variable for this research, the electrolysis capacity is kept infinite for the base scenarios. This has been done due to the scarcity of data on electrolysis, and, more significantly, the objective of this study is to establish a prudent capacity. Therefore the research aims to avoid any potential pitfalls by pre-determining this capacity.

Table 4.3: Base model settings.

Setting	**Value**
Time step	4h
Optimization period	t=1-2190
Block length	2190
Look-ahead	0
Unit currency	MEURO
Unit CO2	kton
Unit electricity	GWh
Unit hydrogen	GWh

Before we can assess the output of the base scenarios, it is particularly important to make a remark regarding the values for system costs and CO_2 emissions. These values are only based on the marginal costs of the generation units for electricity and hydrogen. Investment, except for electrolysis in some experiments, operation & maintenance (O&M) and many other costs are not included. The same goes for carbon emissions, which are solely based on the consumption of carbon-emitting energy carriers like gas for the production of electricity and hydrogen. Other emissions stemming from, for example, other fuels consumed, transportation or construction of the asset are not included. The exact values are, therefore, not representative of the actual costs or emissions of the combined Dutch electricity and hydrogen system. They are, however, extremely valuable in comparing the outcomes of different experiments and the implementation of specific electrolysis capacities. Or in other words, they should be used for relative comparison, not exact prediction. With these remarks in mind, the outcomes of the base scenarios can be found in Table 4.4.

Table 4.4: Outcomes base scenarios.

KPI	System costs [MEURO]	CO_2 emissions [kton]	Electrolysis (max) [GW]	Loss of Load [GWh]
Value 2030	8272	48378	10.94	4
Value 2040	4304	23773	39.41	0

First, due to the higher degree of renewable electricity, the system costs and CO_2 emissions are significantly lower in 2040 compared to 2030. Conventional electricity generation, one of the main factors contributing to the system costs and emissions, has considerably fewer operational hours and generates a lower output measured in GWhs in 2040. This difference can clearly be seen in Figures 4.16 and 4.17. Additionally, it shows the significantly increased flow of electricity in the system. Where the electricity mix in 2030 rarely crosses the 30 GWh line, the electricity mix in 2040 rarely drops below it. This results from the increased supply of renewable electricity and increased electrification across all domains described in Chapter 3.

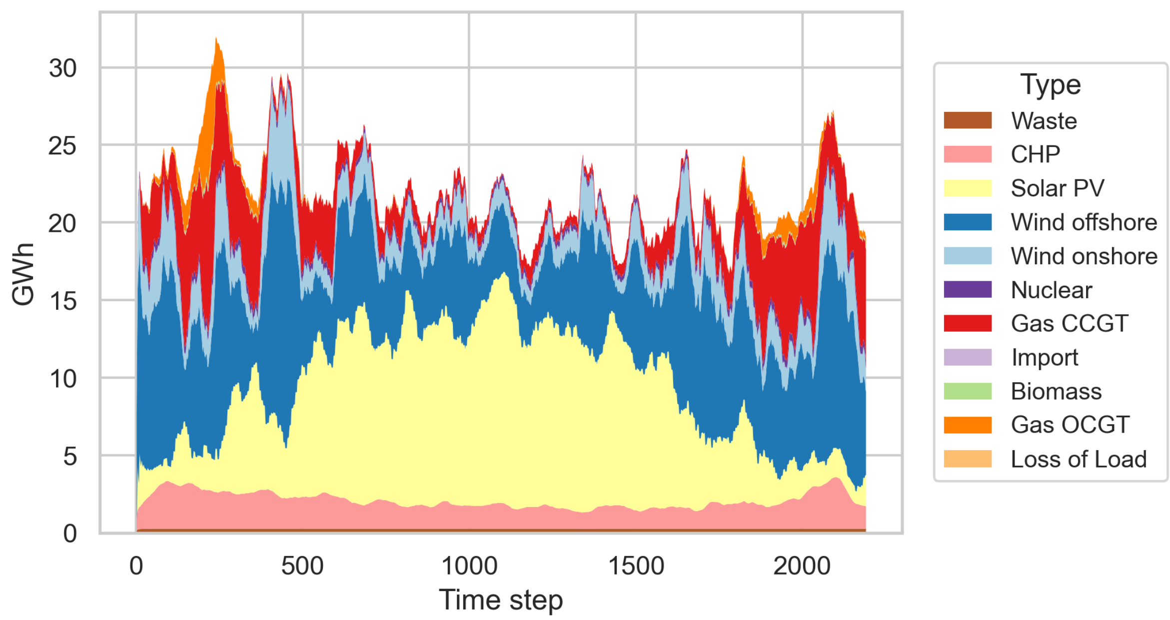

Figure 4.16: Base scenario 2030 - electricity mix, moving average of one week.

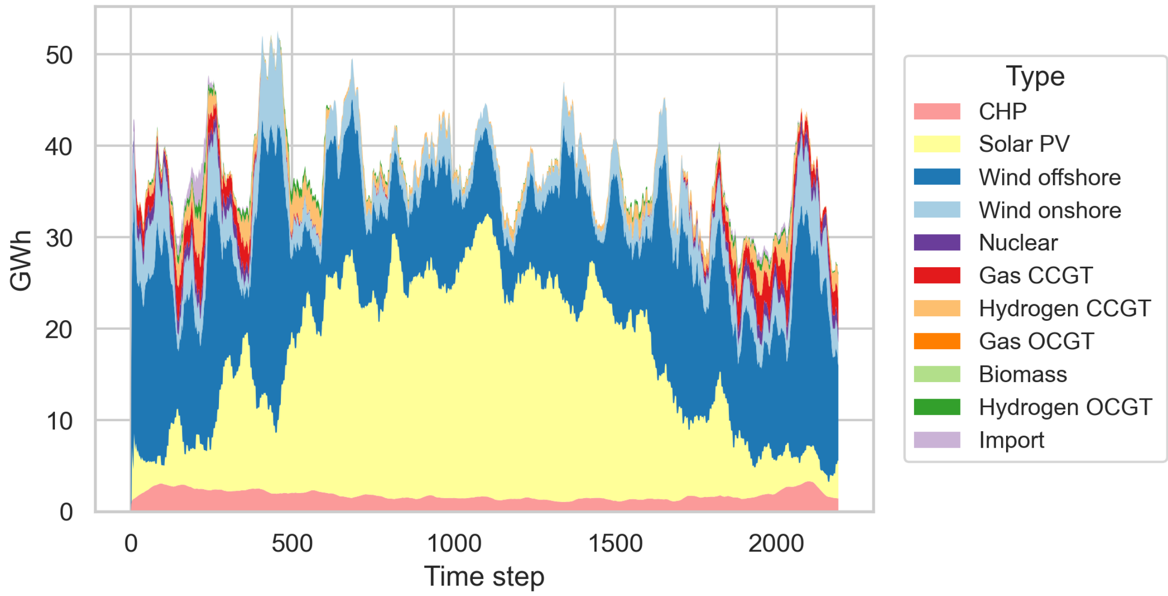

Figure 4.17: Base scenario 2040 - electricity mix, moving average of one week.

Moreover, due to greater utilisation of electrolysis, the use of SMR (with or without CCS) and biomass gasification is also significantly reduced. This automatically results in less emissions and costs in the system.

When taking a closer look at the third KPI, maximum electrolysis capacity used, we can see that the value for 2040 grows almost fourfold compared to 2030. This can be justified by the growth of installed renewable electricity capacity. Being an optimization model, Linny-R will always search for the least costly allocation of its generation assets. When there is a large influx of low-cost renewable electricity, the system will have larger quantities available to convert into hydrogen instead of replacing electricity generation with conventional assets. This behaviour is well-displayed in the residual load duration curves of both the base scenarios in Figure 4.18 and 4.19. This curve is derived by subtracting the variable, and thus inflexible, renewable electricity supply from the electricity demand. We can obtain the residual load duration curve by sorting the residual load curve into descending order. With this curve, we create insights into what would happen if we did not try to balance our renewable energy system with conventional generation, batteries or other flexible mediums. Although depicted in red, the area below the 0-GWh line is the overshoot of renewable electricity and the blue area is the shortage of renewable electricity. The curves show us that in 2040, both the number of hours and the volume of VRES overshoot will grow, allowing for more potential for electrolysis.

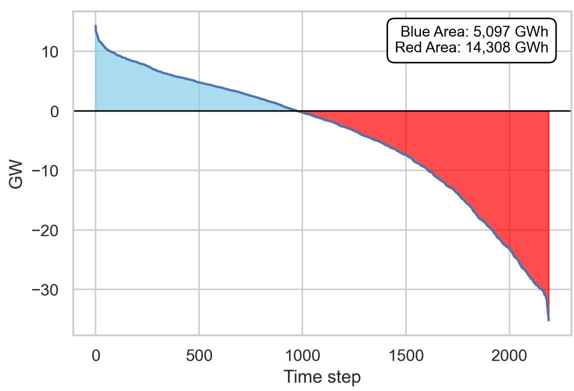

Figure 4.18: Base scenario 2030 - residual load duration curve.

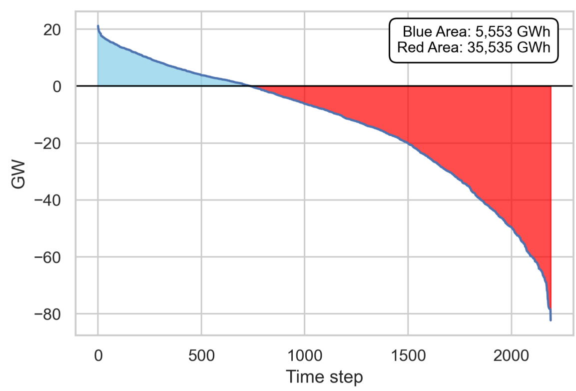

Figure 4.19: Base scenario 2040 - residual load duration curve.

Lastly, a difference in loss of load can be identified. Especially remarkable is the absence of loss of load in 2040. Due to the increased flexibility and the collection of other input variables, this scenario does not show any loss of load. However, in the experiments that will be conducted in Chapter 6, losses of load will occur due to different input variables used. In 2030, the loss of load occurs in two specific periods at the start of February. A confluence of high demand from the built environment (shown in Figure B.1, little renewable generation and the lack of flexibility in 2030 create a system-wide shortage of electricity. In 2040, the built environment demand and weather patterns remain the same. However, the increased flexibility resolves this loss of load issue.

4.4 Verification and validation

This section will test if the conceptual system has been correctly implemented in Linny-r. This will be done in two ways. First, the correctness of the model will be tested through verification. With this, we will check if the model has been built correctly and if it shows the logical and correct behaviour Secondly, the purpose of the model will be tested through validation. With this, we will check whether the model indeed serves as a tool for finding a prudent electrolysis production capacity within the Dutch electricity and hydrogen system.

4.4.1 Verification

During the construction of the Linny-R model, small test runs were constantly performed to test whether the model was still functioning correctly and whether no mistakes were made. In this subsection, we will replicate these test runs and vary the input variables to see if the core functions of the model show the correct behaviour. As we want to cover all model functionalities, including the reconversion of hydrogen to electricity through hydrogen turbines, the 2040 base scenario will be used. The following functionalities will be thoroughly verified; storage behaviour, loss of load occurrence, and the relation between mobility and hydrogen in refineries. By formulating and testing hypotheses, we test whether these functionalities have been implemented correctly.

Additionally, sensitivity analysis is often used to test whether a model is built correctly. This analysis examines the impact of a change in all input variables on the key performance indicators (KPIs). With this, we can verify whether these changes show the correct and expected behaviour and, if not, examine and explain the nature of this behaviour.

Storage behaviour

The behaviour of the storage is affected by many components. We will significantly alter some of its input, output and technical parameters for this verification step. The input is represented through the installed capacity wind offshore for P2X, the output through the installed capacity of hydrogen turbines and the technical parameters through its injection and withdrawal rates. In Table 4.5, the experiments can be found along with the hypotheses of the expected behaviour that should follow from these changes. The results of the experiments are shown in Figure 4.20.

If we closely examine the figure, we can see that all the expected behaviour from the hypotheses is reflected. The effect of the ’reconversion’ experiment is subtle, but this can be explained by the minor use of hydrogen in gas turbines compared to the total hydrogen demand (16.7%) in the base scenario.

Table 4.5: Verification of storage behaviour - inputs.

Experiment	Variable	Value	Variable	Value	Hypothesis
P2X	Installed capacity wind offshore for P2X [GW]	90	-	-	There is much less need for storage. The large capacity of wind energy reserved for offshore wind will result in a much greater production of green hydrogen.
Reconversion	Hydrogen CCGT [GWh/h]	0.594	Hydrogen OCGT [GWh/h]	0.297	The storage will overall be fuller throughout the year. It has fewer options to empty the storage, especially during shortages.
Injection	Injection rate [GWh/h]	0.1	Withdrawal rate [GWh/h]	0.12	The storage fluctuations will be less volatile. It is not possible to quickly charge, or discharge the storage and therefore the fluctuations will be less impactful.

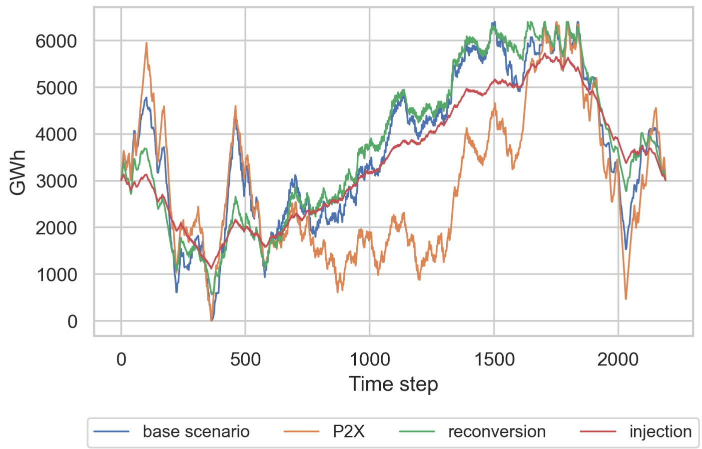

Figure 4.20: Verification of storage behaviour.

Loss of load occurrence

The prevention of loss of load is, next to overall inflexible demand and generation, predominantly determined by the degree of flexibility in the system. The most prominent flexibility options within the system are; gas CCGT and nuclear, lithium-ion storage, hydrogen turbines, industry flexibility and interconnection. By removing one of these options, there should be a high chance of loss of load reoccurring in the system. For this verification step, we will remove these flexibility options from the system one by one to see whether this indeed inflicts a loss of load. The results of this verification analysis can be found in Table 4.6.

As expected, removing the flexibility options from the system invokes additional loss of load in the base scenario. Without this flexibility, the system cannot address the significant mismatches in supply and demand.

Table 4.6: Verification of loss of load occurrence.

Variable with value = 0	Gas CCGT and nuclear	LiOn storage	Hydrogen turbines	Industry flexibility	Interconnection
Loss of Load [GWh]	25	25	114	17	1141

Hydrogen consumption for oil-based fuels

As refineries take on an integral role in both the industry and mobility sector, their behaviour should be adequately verified. The demand for hydrogen by refineries is determined by; (1) the domestic demand for oil-based fuels and; (2) the ratio of external demand for oil-based fuels. In turn, reducing the total demand for oil-based fuels should decrease hydrogen demand and, thus, the level of electrolysis and total emissions. The latter, not being completely straightforward, is reduced due to a reduction in SMR (with or without CCS) production levels.

If we take a closer look at the results of this verification in Table 4.7, we can see that a reduction in the demand for oil-based fuels in fact leads to a reduction in in the total hydrogen demand and thus also CO_2 emissions and electrolysis production.

Table 4.7: Verification of hydrogen consumption for oil-based fuels.

Variable	Base value	Test value	Hydrogen demand	Emissions	Electrolysis
Demand oil-based fuels	2.017	1.017	-1.65%	-0.15%	-7.59%
Percentage of export	0.8	0.7	-1.11%	-0.10%	-7.21%

Sensitivity analysis

The last method used to verify the model is a sensitivity analysis. By conducting this analysis, we can cover verifying the effect of changing all input variables on the KPIs in a clear and concise way requiring only one table. As the sensitivity analysis will also serve as a tool for the creation of the experiment design (Chapter D), an analysis will be conducted for both the base scenarios. By doing so, we can identify critical input variables that significantly influence the optimization model's output and prioritise them in creating the experiment design

The method used for the analysis is one-variable-at-a-time, or OVAT. This entails that each input variable of the model is adjusted individually by a predetermined percentage, which in our case is +20%, while keeping the remaining variables at their standard values. It is important to note that the variables with a zero value in 2030 or 2040 have not been included in this analysis. Nonetheless, the impact of a variable is always represented in either 2030 or 2040. Moreover, the KPI 'total costs' is divided into two categories; 'costs electricity' and 'costs hydrogen'. This is to gain insights into whether the change in system costs stems from a change in electricity production (costs electricity) or hydrogen production (costs hydrogen).

Moreover, as the base scenario for 2040 does not have any loss of load, it currently can not show a variable's potential for reduction of loss of load. For this reason, the value of the input variable 'interconnection capacity' is reduced to the level of the base scenario for 2030, namely 12.8 GW. This value is still within a future reasonable limit and the maximum change in the KPI outcomes is still acceptable. The maximum electrolysis remains the same, while system costs and carbon emission change by +3,39% and -0.04%, respectively. As a result, the loss of load for the base scenario is increased to 48 GWh, and the complete influence of the input variables can be verified. Table 4.8 shows the sensitivity analysis for 2030 and Table 4.9 for 2040.

None of the variables show unexpected or unexplainable behaviour concerning changes in the KPIs. Some variables, however, do not have a directly understandable relation:

- Increased installed capacity in all generation and production units leads to decreased system costs because there are no capital or O&M costs (CAPEX and OPEX). Only the marginal costs of production are considered. So if an asset's installed capacity grows, it can produce more when it is the most cost-effective option, decreasing the overall costs.

- More installed capacity of gas-powered generations and production assets leads to increased carbon emissions. The reason for this is that the model optimizes for the lowest costs. Generation and production with gas instead of other more expensive energy carriers is often an economically beneficial choice.

- In 2030, the loss of load increases when the import price of hydrogen increases. Instead of importing, the model chooses to fully deploy SMR with CCS. The already shortcoming electricity in these hours is then used for SMR with CCS, increasing the loss of load. It is the most cost-effective option to produce hydrogen from SMR with CCS and leads to an overall system costs reduction, accept a small increase in loss of load.

A more extensive breakdown of the sensitivity analysis can be found in Chapter 5.

Table 4.8: Sensitivity analysis base scenario 2030.

	Unit	Costs electricity *MEURO*	Costs hydrogen *MEURO*	Total costs *MEURO*	CO2 emissions *kton*	Electrolysis (max) *GW*	Loss of load *GWh*
Base scenario		-5889	-2383	-8272	48378	10.94	5
Installed capacity nuclear	20%	-0.48%	-0.30%	-0.40%	-0.19%	0.00%	-20%
Installed capacity OCGT	20%	-0.01%	0.00%	-0.01%	0.01%	0.00%	-4%
Installed capacity CCGT	20%	-1.13%	-0.80%	-1.02%	1.02%	0.00%	-100%
Installed capacity biomass	20%	-0.05%	0.00%	-0.04%	0.00%	0.00%	-17%
Installed capacity waste	20%	-0.48%	-0.30%	-0.40%	-0.13%	0.00%	-12%
Installed capacity wind onshore	20%	-2.44%	-2.60%	-2.48%	-0.85%	0.00%	-27%
Installed capacity wind offshore	20%	-7.08%	-8.20%	-7.54%	-2.69%	0.00%	-68%
Installed capacity wind offshore for P2X	20%	-0.01%	-0.20%	-0.08%	-0.02%	0.00%	0%
Installed capacity solar PV	20%	-2.27%	-8.20%	-4.59%	-1.94%	0.00%	0%
Biomass price	20%	0.29%	0.40%	0.33%	0.06%	0.00%	0%
Uranium price	20%	0.30%	0.00%	0.19%	0.02%	0.00%	0%
Gas price	20%	10.00%	9.80%	9.91%	-0.89%	0.00%	0%
Import price electricity	20%	1.60%	0.20%	1.04%	0.01%	0.00%	0%
Import price hydrogen	20%	2.38%	-2.20%	0.59%	0.21%	0.00%	37%
Interconnection capacity	20%	-0.19%	-0.10%	-0.15%	0.02%	0.00%	-100%
Import capacity hydrogen	20%	0.00%	0.00%	0.00%	0.00%	0.00%	0%
By-product hydrogen production	20%	-0.44%	-17.60%	-7.20%	-1.89%	-7.31%	0%
Installed capacity SMR with CCS	20%	-1.22%	-2.20%	-1.59%	1.22%	0.00%	0%
Installed capacity biomass gasification	20%	-0.08%	-0.20%	-0.14%	-0.05%	0.00%	0%
Industrial heat demand	20%	45.02%	76.50%	57.42%	23.72%	30.94%	574%
Electricity ratio of industrial heat demand	20%	11.75%	6.10%	9.52%	2.92%	0.00%	502%
Hydrogen ratio of industrial heat demand	20%	2.72%	19.30%	9.26%	1.53%	8.50%	5%
Flexible industry capacity	20%	-0.92%	-6.40%	-3.06%	-0.16%	-8.34%	-92%
Heating demand built environment	20%	22.34%	5.10%	15.55%	8.04%	0.00%	3915%
Electricity ratio of heating demand built environment	20%	22.34%	5.10%	15.55%	-6.22%	0.00%	3915%
Heat network ratio of heating demand built environment	20%	0.00%	0.00%	0.00%	-2.07%	0.00%	0%
Energy demand mobility	20%	9.11%	10.70%	9.75%	2.54%	2.64%	340%
Electricity ratio of energy demand mobility	20%	8.49%	2.30%	6.04%	2.09%	-0.90%	336%
Hydrogen ratio of energy demand mobility	20%	0.09%	3.80%	1.55%	0.30%	1.52%	1%
Other ratio of energy demand mobility	20%	-0.07%	-1.60%	-0.66%	-0.16%	-0.66%	0%
External demand for oil-based fuels	20%	0.40%	8.30%	3.51%	0.50%	3.41%	2%
Hydrogen demand as a feedstock	20%	0.58%	9.70%	4.16%	0.60%	4.03%	2%
Electricity demand agriculture	20%	1.98%	1.10%	1.63%	0.55%	0.00%	64%
Electricity demand ICT	20%	1.96%	1.10%	1.61%	0.55%	0.00%	63%
Numer of underground hydrogen storages	20%	0.00%	-0.50%	-0.18%	0.07%	0.00%	0%
Lithium-ion storage capacity	20%	-2.30%	0.50%	-1.19%	-0.07%	0.00%	-100%
Carbon price	20%	7.83%	5.70%	6.99%	-0.84%	0.00%	0%

Table 4.9: Sensitivity analysis base scenario 2040.

	Unit	Costs electricity *MEURO*	Costs hydrogen *MEURO*	Total costs *MEURO*	CO2 emissions *kton*	Electrolysis (max) *GW*	Loss of load *GWh*
Base scenario		-3990	-460	-4450	23764	39.41	48
Installed capacity nuclear	20%	-1.90%	-3.10%	-2.00%	-0.60%	0.00%	-23%
Installed capacity OCGT	20%	0.00%	0.00%	0.00%	0.00%	0.00%	0%
Installed capacity CCGT	20%	-4.40%	-0.60%	-4.00%	1.10%	0.00%	-75%
Installed capacity biomass	20%	-0.10%	0.00%	-0.10%	0.00%	0.00%	-2%
Installed capacity wind onshore	20%	-3.00%	-20.50%	-4.60%	-1.80%	0.00%	-19%
Installed capacity wind offshore	20%	-9.90%	-48.90%	-13.60%	-5.20%	0.00%	-40%
Installed capacity wind offshore for P2X	20%	-0.10%	-11.00%	-1.10%	-0.50%	0.00%	0%
Installed capacity solar PV	20%	-3.30%	-26.90%	-5.50%	-2.30%	0.00%	-20%
Biomass price	20%	0.00%	0.00%	0.00%	0.00%	0.00%	0%
Uranium price	20%	0.60%	0.80%	0.60%	0.10%	0.00%	0%
Gas price	20%	5.50%	0.50%	5.00%	-0.20%	0.00%	0%
Import price electricity	20%	1.00%	25.40%	3.30%	1.70%	0.00%	0%
Import price hydrogen	20%	0.20%	8.50%	0.90%	0.10%	0.00%	0%
Interconnection capacity	20%	-3.40%	-2.20%	-3.30%	-0.10%	0.00%	-100%
Import capacity hydrogen	20%	0.00%	-7.00%	-0.70%	-1.10%	0.00%	0%
By-product hydrogen production	20%	-1.50%	-34.90%	-4.60%	-2.30%	-2.17%	0%
Installed capacity SMR with CCS	20%	0.00%	-0.10%	0.00%	0.00%	0.00%	0%
Installed capacity biomass gasification	20%	0.00%	0.00%	0.00%	0.00%	0.00%	0%
Industrial heat demand	20%	70.30%	430.90%	103.80%	49.30%	1.84%	187%
Electricity ratio of industrial heat demand	20%	21.30%	67.10%	25.50%	5.80%	0.00%	179%
Hydrogen ratio of industrial heat demand	20%	2.30%	97.70%	11.10%	4.20%	3.18%	0%
Flexible industry capacity	20%	-12.40%	-17.80%	-12.90%	-3.30%	-7.43%	-100%
Heating demand built environment	20%	38.50%	39.90%	38.60%	9.70%	0.00%	595%
Electricity ratio of heating demand built environment	20%	38.50%	39.90%	38.60%	-18.60%	0.00%	595%
Heat network ratio of heating demand built environment	20%	0.00%	0.00%	0.00%	-10.00%	0.00%	0%
Energy demand mobility	20%	29.00%	116.50%	37.10%	9.00%	1.16%	236%
Electricity ratio of energy demand mobility	20%	27.30%	61.60%	30.50%	6.50%	-0.64%	236%
Hydrogen ratio of energy demand mobility	20%	1.00%	25.00%	3.20%	1.40%	0.97%	0%
Other ratio of energy demand mobility	20%	0.00%	-9.40%	-0.90%	-0.40%	-0.32%	0%
External demand for oil-based fuels	20%	0.10%	2.10%	0.30%	0.20%	0.10%	0%
Hydrogen demand as a feedstock	20%	1.00%	33.40%	4.00%	1.70%	1.20%	0%
Electricity demand agriculture	20%	3.20%	6.40%	3.50%	1.10%	0.00%	24%
Electricity demand ICT	20%	3.90%	7.90%	4.30%	1.20%	0.00%	29%
Installed capacity hydrogen OCGT	20%	-0.70%	0.70%	-0.50%	0.00%	0.00%	-15%
Installed capacity hydrogen CCGT	20%	-5.30%	3.50%	-4.50%	-0.70%	0.00%	-47%
Numer of underground hydrogen storages	20%	0.00%	-10.00%	-0.90%	-0.70%	0.00%	0%
Lithium-ion storage capacity	20%	-10.20%	10.60%	-8.20%	-0.40%	0.00%	-85%
Carbon price	20%	9.80%	1.70%	9.10%	-0.30%	0.00%	0%

4.4.2 Validation

Validation refers to the process of establishing that the right model is built for the objective of this research. Or, in other words, how effective the model is in achieving our goals. One of the most common methods is validating the model's outcomes with historical data. As this research revolves around constructing a model of the future Dutch energy system, historical data is unavailable. However, several entities have published reports attempting to forecast the composition of the future Dutch energy system. In this section, we will conduct validation runs using the input values from these reports and their corresponding model. We will then compare the behaviour and outcomes of our model with those described in the reports. This method of validation is known as cross-model validation. For the base scenario of 2030, validation will be conducted using the IP2024 report, written by Netbeheer Nederland [86]. To be more precise, the scenario 'Klimaatambitie', based on all existing and planned energy and climate policies, together with the government's ambition for additional agenda-driven policy from the Coalition Agreement. The implementation of the scenario in the Energy Transition Model is also utilized. For the base scenario of 2040, validation will be conducted using the II3050 report, also written by Netbeheer Nederland [85]. Precisely, the 'Nationaal Leiderschap (NAT)' (National Leadership) scenario. In this scenario, the Dutch government aims for an energy-efficient system powered mainly by domestic capabilities and production. If the reports, or published models behind the reports, offer equal or somewhat equal outputs to our model, they will be compared for validation. By doing so, we can determine if our model is able to achieve its intended purpose; the prediction of (a part of) the future Dutch energy system.

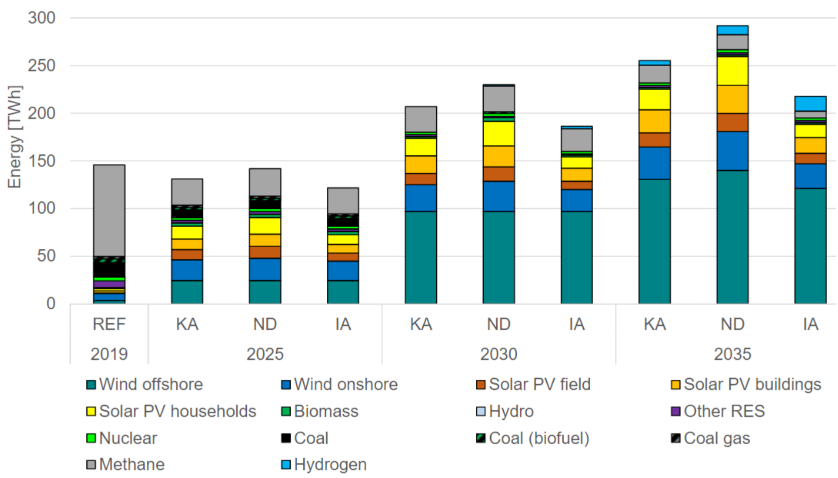

Figure 4.21: Validation - electricity supply IP2024, scenario KA.

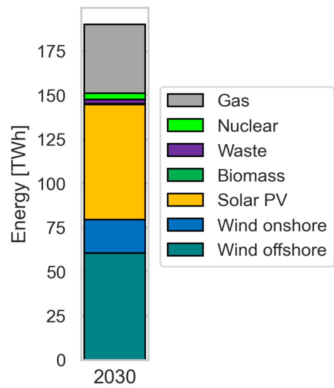

Figure 4.22: Validation - electricity supply model.

Figure 4.21 gives the electricity supply mix for the three scenarios and simulation years of IP2024. The bin 'KA' in 2030 is the scenario that has been reproduced for this validation run. In Figure 4.22, the results of the validation run from our model are given, grouped as uniformly as possible, While gas, biomass and nuclear have similar outputs of generation, a slight difference can be found in the generation of renewable energy sources. As the installed capacities are identical in both simulations, the difference can be clarified based on the weather data used. While we use historical data from renewables.ninja, ETM defines its own weather data, which can be adjusted to the user's wishes. In this scenario, the number of full load hours equals 4500 for offshore and 3100 for onshore wind. In the data used in the model, average loads of 32.4% (2800 hours) for offshore and 24.1% (2100 hours) for onshore are achieved. This is considerably lower than the loads used in the ETM model, which explains the lowered output of VRES.

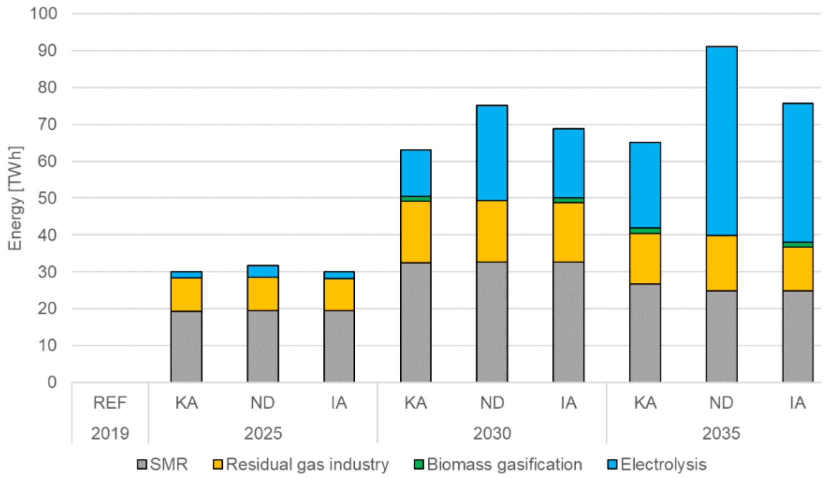

Figure 4.23: Validation - hydrogen supply IP2024, scenario KA.

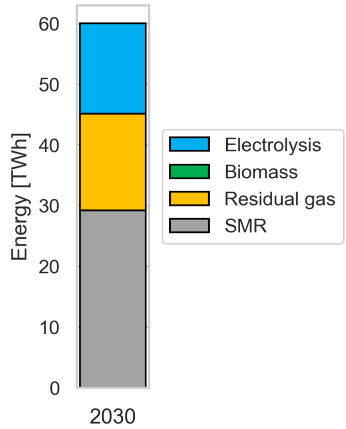

Figure 4.24: Validation - hydrogen supply model

The second validation method is the total hydrogen production per production type. Figure 4.23 gives the hydrogen supply from the IP2024 scenarios, Figure 4.24 the hydrogen supply from the validation run in our model. All outputs are approximately the same level in both figures, except for production from biomass gasification. This can be explained by the fact that, in the model, production with biomass is more costly than production with SMR. As our model focuses solely on cost optimization, and the production of SMR is still predominantly below the upper bound, biomass is used less often. In the ETM model, biomass gasification production depends on much more factors like the plants needing to recoup their investment or production objectives from policies. This thus results in slightly different outputs, but they can still be deemed valid.

In addition, we validate the behaviour of lithium-ion batteries (Figure 4.26) by comparing its behaviour to the behaviour of large-scale batteries as derived from the ETM (Figure 4.25). Both of the figures give a snapshot of January. The large-scale batteries in the ETM model are fully charged on 21 different occasions, while the batteries in our model are fully charged on 23 different occasions. This, in combination with some similar smaller peaks in similar time steps, demonstrates that the behaviour of both battery storage is similar and thus validated.

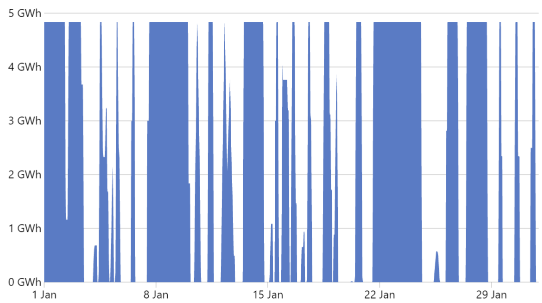

Figure 4.25: Validation - large-scale batteries behaviour January IP2024, scenario KA (derived from ETM).

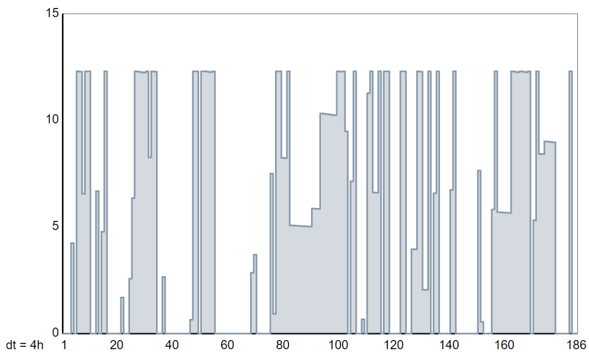

Figure 4.26: Validation - battery behaviour model January.

To validate the 2040 model, the electricity supply mix of II3050 is also considered. Figures 4.27 and 4.28 give the electricity supply mix for II3050, scenario NAT and our own model, respectively. Similar to 2030, the electricity generation from wind is considerably lower due to the difference in production factor. However, an additional difference can be found in the gas and import levels. Comparing the II3050 electricity mix to our electricity mix, gas generation is lower, while import is much higher. This can be explained based on how import is modelled in our work, functioning as a last-resort flexibility option with a cost price higher than the costliest domestic electricity generator. Generation with natural gas thus replaces the import in our model, as approximately the same values can be found after summation. All other generation assets show similar values.

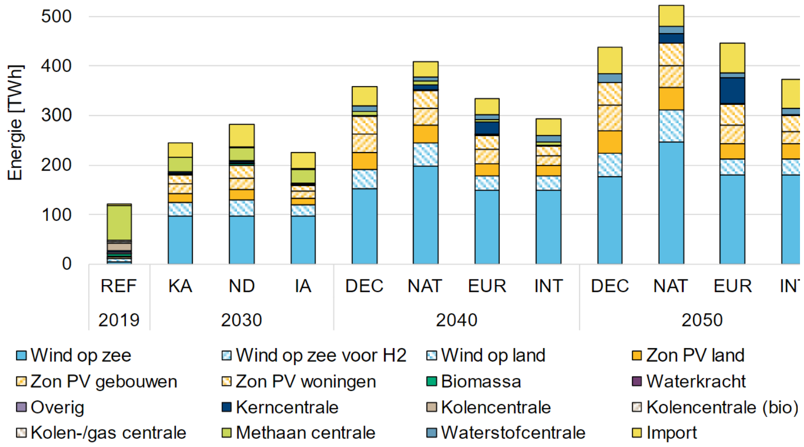

Figure 4.27: Validation - electricity supply II3050, scenario NAT.

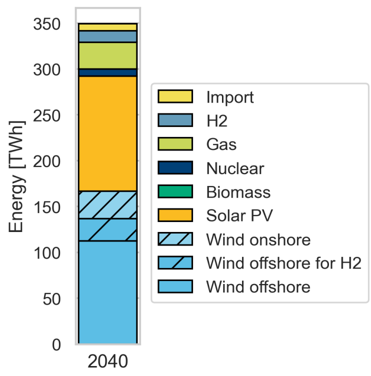

Figure 4.28: Validation - electricity supply model 2040.

The next validation for 2040 concerns hydrogen production per production type. Figure 4.29 gives the hydrogen production for the II3050 scenarios, Figure 4.30 the production for our model. In the II3050 scenario, a distinction is made between dedicated offshore electrolysis and flexible electrolysis on land. In our model, this is grouped. Both the total production of hydrogen and the separate categories are in the same order of magnitude. Only a slight decrease in SMR production is found in our model compared to II3050. This can be explained based on the difference in wind generation in the electricity mix. Due to the reduced wind generation in our model, there will be an increased frequency of periods with insufficient renewable electricity available for electrolysis. As a result, SMR will be required to compensate and provide the hydrogen necessary to meet the demand more frequently.

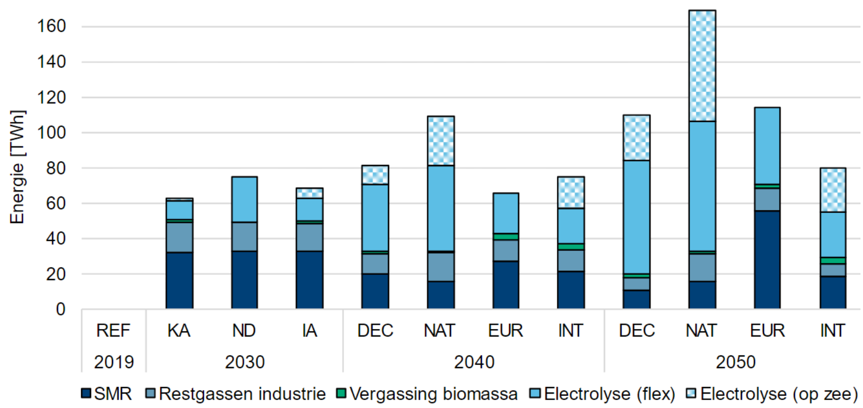

Figure 4.29: Validation - hydrogen supply II3050, scenario NAT.

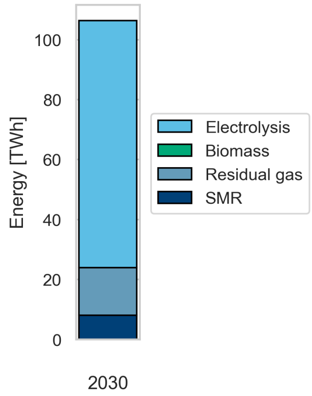

Figure 4.30: Validation - hydrogen supply model 2040

In addition to this cross-model validation, experts were consulted during the course of this work, as we held several presentation sessions with experts from TU Delft, Energie Beheer Nederland and TNO. In these sessions, the model and its results were presented to check whether; (1) the outcomes are in an acceptable range and serve the right purpose and; (2) the model can give an answer to the main questions in this research. After each session, adjustments could be made to improve either the model itself or the insights gained from the outcomes. Some examples are:

- Addition of tables that give insights into the number of full load hours and average load in Chapter 6.
- Addition of tables showcasing the LCOH in the different series of experiments in Chapter 6.
- Addition of electricity consumption of hydrogen injection into the model's storage facilities.

Chapter 5

Experiment design

Following the implementation of the model, the next step in the M&S Life-cycle is experimentation. For this, an experiment design will be created. As we deal with a large number of uncertain input variables, a selection has to be made. Incorporating all of these variables into the experiments would lead to unattainable large experiments that are simply not executable on the equipment available. For this reason, we first conduct an impact-uncertainty analysis, giving insights into the most impactful and uncertain input variables. By doing so, we are able to make a well-argued selection of the most critical variables, which will in turn be incorporated into the experiments. Following this, we will create several experiments that aim to create insights needed to answer the research questions.

5.1 Impact-uncertainty analysis

The objective of the impact-uncertainty analysis is to first assess and rank the impact of each input variable on the system, particularly the KPIs. Additionally, the analysis aims to rank the input variables based on the level of uncertainty resulting from the range of the collected data. The outcome that will be generated is an impact-uncertainty table, ranking the most critical input variables.

5.1.1 Impact analysis

The starting point for the impact analysis is the sensitivity analysis conducted in Chapter 4. The results from this analysis allow us to see the individual impact on the KPIs for each input variable. In general, if the absolute impact of an input variable on an output variable is greater than delta (δ), the original change in the input variable, it is considered sensitive [115]. Considering our delta of +20%, every input variable that inflicts a change greater than 20% (positive or negative) can be considered sensitive. However, the impact on the KPI 'Loss of Load' is approached differently. The outcomes for the base scenarios for 2030 and 2040 are 4 and 48, respectively. Small changes in these numbers quickly lead to significant relative changes (expressed in %.) For this reason, we consider a change of more than 100% as sensitive for this KPI. Following this line of reasoning, we can normalize the impact of every input variable to a relative impact from 1 to 5, where 5 is the most significant, using the assessment criteria as shown in Table 5.1. By then taking the maximum relative impact of each input variable, we can rank all the input variables based on their impact on the KPIs. A comprehensive version of this analysis can be found in Appendix D.

Table 5.1: Impact assessment criteria.

Total costs	CO2 emissions	Electrolysis (max)	Loss of load	Relative impact
0-5%	0-5%	0-5%	0-24%	1
6-10%	6-10%	6-10%	25-49%	2
11-15%	11-15%	11-15%	50-74%	3
16-20%	16-20%	16-20%	75-99%	4
20+%	20+%	20+%	100+%	5

5.1.2 Uncertainty analysis

The uncertainty of the input variables is based on the uncertainty of the input data. Different steps are conducted to reach the final value for uncertainty, ranging between 1 and 5. First, we base the uncertainty on the input ranges in the data retrieved from (grey) literature. In total, 20 scenarios stemming from 8 reports were assessed to establish the uncertainty ranges. Additionally, mono-topic web pages, articles or reports were consulted to retrieve stand-alone data for specific variables. Examples of this are import and carbon prices. All these values are assembled in an easy-to-use spreadsheet that can be assessed through this spreadsheet[1]. For each variable, The relative uncertainty for each variable was calculated by using the range of collected data. These relative uncertainties are then ranked by normalizing the value between 1 and 5. If none or just one input value could be retrieved from the literature, the relative uncertainty is not representative of this data's uncertainty level. In this scenario, we aim to investigate the factors contributing to the scarcity of available data on the subject matter. An example of this is weather data, which can simply not be expressed in a value and is therefore perceived as highly uncertain. More information on relative uncertainty and the exact composition of the other values can be found in Appendix D. An important thing to note is that we are thus not discussing the stochastic uncertainty (except for the weather conditions) but the uncertainty in projections and, thus, the future development of system elements. If projections are widely spread, the development of an element can be viewed as more uncertain.

The impact-uncertainty table can be constructed now that both the impact and uncertainty values for each input variable are obtained. For this table, the variables are first sorted by impact and then by uncertainty. This approach was adopted to address the pitfall of varying variables that are highly uncertain but have minimal impact on the KPIs. The experiment design aims to provide the broadest possible picture of the future energy system. It is, therefore, essential to prioritize variables that generate substantial changes. As a result, the impact-uncertainty tables for 2030 and 2040 can be found in Table 5.2.

Table 5.2: Impact-uncertainty tables. Selected variables are underlined.

2030			**2040**		
Variable	**Impact**	**Uncertainty**	**Variable**	**Impact**	**Uncertainty**
Wind speed	5	5	Wind speed	5	5
Solar irradiance	5	5	Solar irradiance	5	5
Installed capacity CCGT	5	3	Energy demand mobility	5	3
Electricity ratio of energy demand mobility	5	3	Interconnection capacity	5	2
Lithium-ion storage capacity	5	3	Industrial heat demand	5	2
Heating demand BE	5	2	Electricity ratio of industrial heat demand	5	2
Interconnection capacity	5	2	Flexible industry capacity	5	2
Industrial heat demand	5	2	Electricity ratio of energy demand mobility	5	2
Flexible industry capacity	5	2	Heating demand BE	5	1
Energy demand mobility	5	2	Electricity ratio of heating demand BE	5	1
Electricity ratio of industrial heat demand	5	1	Installed capacity CCGT	4	3
Electricity ratio of heating demand BE	5	1	Lithium-ion storage capacity	4	3
Installed capacity wind offshore	3	2	Installed capacity wind offshore	3	2
Electricity demand agriculture	3	2	Hydrogen ratio of industrial heat demand	3	2
Electricity demand ICT	3	2	Installed capacity hydrogen CCGT	2	3
By-product hydrogen production	2	4	Heat network ratio of heating demand BE	2	2
Installed capacity wind onshore	2	2	Installed capacity nuclear	2	1
Heat network ratio of heating demand BE	2	2	Electricity demand ICT	2	1
Carbon price	2	2	Carbon price	2	1
Gas price	2	1	Installed capacity OCGT	1	5
Hydrogen ratio of industrial heat demand	2	1	Installed capacity CCGT with CCS	1	5
Installed capacity OCGT	1	5	Installed capacity biomass	1	5
Import capacity hydrogen	1	5	Installed capacity wind offshore for P2X	1	5
Installed capacity biomass gasification	1	5	Uranium price	1	5
Hydrogen ratio of energy demand mobility	1	5	Hydrogen ratio of energy demand mobility	1	5
Biomass price	1	4	Import capacity hydrogen	1	4
Installed capacity SMR with CCS	1	4	By-product hydrogen production	1	4
External demand for oil-based fuels	1	4	External demand for oil-based fuels	1	4
Hydrogen demand as a feedstock	1	4	Hydrogen demand as a feedstock	1	4
Installed capacity biomass	1	4	Number of underground hydrogen storages	1	4

[1] https://docs.google.com/spreadsheets/d/1sTR9id_cf9hNhRiPZOD3G6TMWvSzuS_v/edit#gid=2103789454

Table 5.2: Impact-uncertainty tables. Selected variables are underlined.

2030			2040		
Installed capacity wind offshore for P2X	1	3	Import price hydrogen	1	4
Installed capacity solar PV	1	3	Installed capacity biomass gasification	1	3
Import price hydrogen	1	3	Installed capacity wind onshore	1	2
Other ratio of energy demand mobility	1	2	Installed capacity solar PV	1	2
Installed capacity nuclear	1	1	Biomass price	1	2
Import price electricity	1	1	Installed capacity SMR with CCS	1	2
Number of underground hydrogen storages	1	1	Other ratio of energy demand mobility	1	2
Installed capacity CCGT with CCS	1	1	Electricity demand agriculture	1	2
Installed capacity waste	1	1	Installed capacity hydrogen OCGT	1	2
Uranium price	1	1	Installed capacity waste	1	1
Installed capacity hydrogen OCGT	1	1	Gas price	1	1
Installed capacity hydrogen CCGT	1	1	Import price electricity	1	1

The next step in creating the experiment design is determining which input variables will be incorporated and varied. First, the design must ensure variations occur on the demand, supply and storage sides for both hydrogen and electricity. Given this prerequisite, we select the variables with the highest combined score, the sum of impact and uncertainty, provided that it does not have a score of 1 for either impact or uncertainty. The results from this selection are underlined in the table above and their input ranges can be found in Tables 5.3 and 5.4. Due to computational limitations, each experiment's maximum number of variables is 10. Given that each variable can take on two values, the total number of runs amounts to 1024. In some experiments, explained later in this chapter, the total number of input variables has to be reduced to 8. In the design for 2030, although 'by-product hydrogen' is ranked lower, it is still included because the other two variables, representing mobility demand and electricity supply, are already accounted for by other variables. 'By-product hydrogen' represents the only form of hydrogen supply in this design. In the design for 2040, the same applies to 'hydrogen CCGT'. Reconversion of hydrogen to electricity is expected to fulfil an essential role in the security of supply by some studies [130, 127, 85]. For this reason, we want to test its effect on the KPIs by accommodating the variable in all experiments for 2040. In addition, only one value for the input variable, 'by-product hydrogen production', could be retrieved from the literature. To address this issue, we assume the lower input variable to be -25% of the base value.

Table 5.3: Experiment variables 2030.

Abbr.	**Variable**	**Lowest value**	**Highest value**	**Unit**
GAS	Installed capacity CCGT	6	14.7	GW
EMB	Electricity ratio of energy demand mobility	0.06	0.23	-
LI	Lithium-ion storage capacity	6.14	12.3	GW
BE	Heating demand built environment	109722	146667	GWh/y
INT	Interconnection capacity	12.8	25	Gw
IH	Industrial heat demand	104167	158400	GWh/y
FL	Flexible industry capacity	1.5	2	GW
MB	Energy demand mobility[1]	113700	171667	GWh/y
OFF	Installed capacity wind offshore[1]	12	21.5	GW
BH2	By-product hydrogen production	11398[2]	15917	GWh/y

[1]Not included in all experiments.[2] -25% of base value.

Table 5.4: Experiment variables 2040.

ID	Variable	Lowest value	Highest value	Unit
MB	Energy demand mobility	88357	228611	GWh/y
INT	Interconnection capacity	14.8	25	GW
IH	Industrial heat demand	104167	184600	GWh/y
EIH	Electricity ratio of industrial heat demand	0.33	0.53	-
FL	Flexible industry capacity	2.5	5.1	GW
EMB	Electricity ratio of energy demand mobility	0.05	0.23	-
GAS	Installed capacity CCGT	2.086	8.5	GW
LI	Lithium-ion storage capacity[1]	10	42.2	GW
OFF	Installed capacity wind offshore[1]	31.5	45	GW
H2T	Installed capacity hydrogen CCGT	2.97	9	GW

[1]Not included in all experiments.

5.2 Composing the experiments

With the selection of all the input variables that will be varied, the experiments can now be constructed. In total, four different series of experiments have been composed. These series of experiments will be conducted for the two weather years and the simulation years 2030 and 2040. As a result of the limited availability of time and reduced relevance for 2030, the last two series of experiments will only be conducted for the simulation year 2040. The exact reasoning will be explained hereafter. In each series of experiments, the variables in Table 5.3 and 5.4 will be varied with the lowest and highest value obtained from the literature. From this point onwards, we call a given combination of these input variables a scenario. An experiment thus consists of 1024 scenarios. By considering these large ranges of uncertainty, we can draw a comprehensive picture of an electrolysis capacity that can be considered prudent for each scenario of the future Dutch energy system. An overview of the resulting experiment design, along with the number of runs per experiment, can be found in Table 5.5.

Potential exploration Our first subquestion, *"What is, based on the availability of renewable electricity, the potential for production capacity of green electrolytic hydrogen in 2030, if current Dutch and European policies are continued?"* aims to give insights into the potential for electrolysis, unrelated to potential investments or comparison between capacities. For these experiments, the electrolysis capacity is assumed to be infinite. The maximum electrolysis capacity for each run in this experiment design will then give us insights into the bare maximum overshoot of electricity available for conversion to hydrogen. If this capacity is adopted, it will result in minimal wastage of valuable renewable electricity. Moreover, with this experiment, we create an overview of the range of capacities (in GW) that fit into the system. This overview is essential for formulating the second experiment, as it will form the basis for the range of capacities that will be compared. It is computationally not feasible to compare more than 6 capacities while still giving room to uncertainties in the design. Thus, a selection has to be made, which this first experiment facilitates. This experiment will be conducted for 2030 and 2040, as we want to compare the capacities for both simulation years.

Capacity comparison For the second series of experiments, electrolysis capacities will be compared. Based on the range of capacities resulting from the first series of experiments, 6 capacities for each simulation year are determined. Their effect on the KPIs will then be tested over the ranges of insecurities as defined in Table 5.3 and 5.4. Since the design must comply with a feasible number of runs, these experiments will be conducted with 2 fewer input variables, denoted by '1' in the tables. In the assessment of experiments, the mini-max regret approach will be utilised as introduced in Chapter 2. The maximum regret for each KPI is compared across all capacities in the design. The capacity (or capacities) that has (or have) the lowest maximum regret for a particular KPI, can be considered as the most prudent, as adding additional capacity will, in no scenario, result in better outcomes. An important thing to note is that, in this experiment, the investment costs are not accounted for in the optimization. Therefore, the calculation of overinvestment will be based on deductive reasoning. To determine the actual cost reduction, we subtract the cost reduction per GW from the investment costs per GW. This calculation allows us to assess the true extent of cost reduction. In this situation, it is essential to understand that achieving a low regret value in system costs may not always directly be the most prudent capacity, as investments also need to be considered. This experiment will be conducted for both 2030 and 2040.

Investment decision As opposed to the deductive reasoning in the second series of experiments, we let Linny-R determine the optimal capacity by including an investment decision for this series of experiments. Here, the electrolysis capacity is divided into standard units of 200 MW. Each standard unit has an annuity of 4 MEURO, based on the total investment costs for a stack, divided by its expected lifetime. The calculations behind this annuity are in Appendix D, Table A.2. Two runs, using the normal weather year, with 1.5 and 2 times the investment costs will be performed as validation to test the sensitivity of the model. Linny-R will invest in an additional electrolyser stack if this leads to an overall cost reduction at the end of the optimization period. These experiments will allow for cross-validation between the deductive and investment approaches. With the investment approach, costs are the main factor driving the investment decision, while in the deductive approach, the user can determine whether additional capacity is worth it by evaluating all KPIs. Both outcomes can then be compared to see if it leads to the same prudent capacity. This series of experiments will only be conducted for the simulation year 2040. In contrast to the first subquestion, the second subquestion, *"How does the prudent production capacity of green electrolytic hydrogen depend on key uncertainties in 2040?"*, aims to create insights into how these prudent capacities depend on the varied uncertainties. By comparing these two approaches to determining a prudent capacity, their correlation with these uncertainties can also be compared.

Storage dependency The last series of experiments solely serves as a tool for answering the last sub-question, *"To what extent does large-scale hydrogen storage determine the prudent capacity for electrolytic hydrogen production?"*. As opposed to the electrolyser capacity, it is the effect of the standard-sized number of underground hydrogen storage facilities that will be compared while setting the electrolyser capacity itself at infinite. For each scenario in these experiments, the ratio between storage capacity and maximum electrolysis demanded by the system is determined, giving insights into the potential hydrogen storage can offer to electrolysis. Additionally, one of the experiments will include a doubling in the injection and withdrawal rate, as this proved to be influential for the electrolysis capacity during the construction of the model. These experiments will also be conducted for 2040 only, as this simulation year also involves the reconversion of hydrogen into electricity, and the system is more dependent on electrolysis (compared to 2030). Moreover, only the normal weather year will be used for this series. Validation runs showed that the dunkelflaute year did not result in a difference in the ratios between storage and electrolysis, only in the total storage throughput. As this is not the objective of the third subquestion, only one weather year is used to limit the size of the experiment design.

Table 5.5: Experiment design.

Year	**Experiments series**	**Condition**	**Runs**	**Experiment ID**
2030	Potential exploration	Normal year	1024	1
		Dunkelflaute	1024	2
	Capacity comparison	Normal year	1536	3
		Dunkelflaute	1536	4
2040	Potential exploration	Normal year	1024	5
		Dunkelflaute	1024	6
	Capacity comparison	Normal year	1536	7
		Dunkelflaute	1536	8
	Investment decision	Normal year	3072	9
		Dunkelflaute	1024	10
	Storage behaviour	Normal rate	2048	11
		Double rate	2048	12

Chapter 6

Results

This chapter will analyse the results of running the experiment design through the model. The sections are structured according to the series of experiments as given in Table 5.5. The results of each series of experiments are analysed in a different section, allowing us to interpret the results individually. In the next chapter, we can discuss these results by comparing and aggregating the information.

6.1 2030 - Exploration of the potential for electrolysis

In this series of experiments, the electrolysis capacity is left unrestricted so that the potential for electrolysis, based on the availability of electricity and demand for hydrogen, can be examined. The maximum electrolysis level, in this case, thus tells us what the maximum amount of hydrogen is that can be created from renewable electricity, during one or more time steps a year, while trying to minimise the overall system costs. Table 6.1 displays the refined heat map of all maximum electrolysis levels across the 1024 experiments, ranging from 8.77 to 13.09 GW. The abbreviations of the experiment variables in all heat maps are in line with abbreviations in Tables 5.3 and 5.4. The table has been reduced to 5 input variables from the 10 variables that were varied in the experiment because the removed variables did not individually affect the electrolysis potential. The remaining variables are the most determinant for electrolysis potential in 2030.

The range of electrolysis potential will be applied to the next series of experiments, where different capacities are compared. Different weather years did not impact the maximum electrolysis capacity; therefore, only one figure is shown. This can be explained based on the criterium on which the dunkelflaute weather year was selected: a prolonged period with little solar and wind production. The maximum electrolysis capacity is based on the opposite, an overshoot of electricity in combination with the demand for hydrogen. Both these weather years know similar peaks in production (Figure 4.15) and thus have a similar impact on the maximum electrolysis capacity.

In Table 6.5, the results for the average Levelised costs of hydrogen (LCOH) in the entire system are given, considering different electrolysis investment costs per kW. The average levelised cost of electricity (LCOE) is equal to 0.23 MEURO/GWh (or EURO/kWh). However, this is solely considering the marginal generation costs for the electricity system.

Table 6.1: 2030 - potential exploration - refined heat map of maximum electrolysis level.

			IH-h		IH-l	
			EMB-h	EMB-l	EMB-h	EMB-l
MB-l	BH2-h	FL-h	8.77	9.28	10.38	10.89
		FL-l	9.02	9.53	10.63	11.14
	BH2-l	FL-h	9.28	9.8	10.89	11.41
		FL-l	9.53	10.05	11.14	11.66
MB-h	BH2-h	FL-h	9.94	10.71	11.55	12.32
		FL-l	10.19	10.96	11.8	12.57
	BH2-l	FL-h	10.45	11.23	12.06	12.84
		FL-l	10.7	11.48	12.31	13.09

Table 6.2: 2030 - potential exploration - average LCOH.

Electrolyser investment costs		LCOH	
Total	Annuity		
EURO/kW	MEURO/y	MEURO/GWh	EURO/kg
0	0	0.13	4.40
400	20	0.15	4.79
600	30	0.15	4.99
800	40	0.16	5.18
1000	50	0.16	5.38
1200	60	0.17	5.57

The average level of the underground hydrogen storage, with the standard deviation as the shadow, over the 1024 runs is shown in Figure 6.1 and 6.2. In the figures, we can see that the storage functions as a mid-term to long-term storage medium. Over the years, it shows a slight seasonal pattern that can be compared with gas storage. Towards the summer (middle of the year), storage gets filled more, while in the winter (start and end of the run), the storage barely goes past half its capacity of 400 GWh. At the same time, mid-term volatility can be found in the curves. Every 50-200 time steps (week to a month), the storage goes through a more minor cycle where it is first discharged and then restored to the previous level. The slight standard deviation indicates little variation in this behaviour over the different runs. In the dunkelflaute year, the storage is more volatile and one considerable drop in storage level can be spotted compared to the 2019 weather year. Around time step 2100, the storage levels drop below 200 GWh. This corresponds to a reduced wind output that does not occur in the normal year, shown in Figures B.3 B.2.

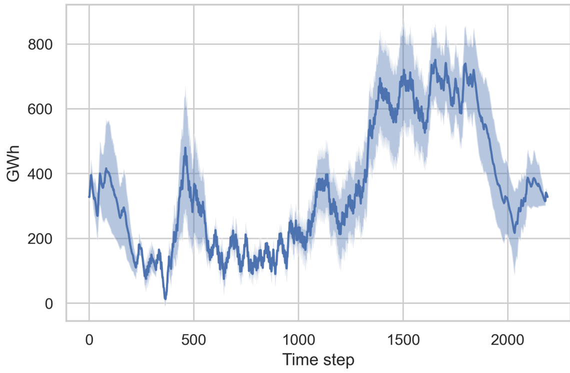

Figure 6.1: 2030 - potential exploration - storage behaviour.

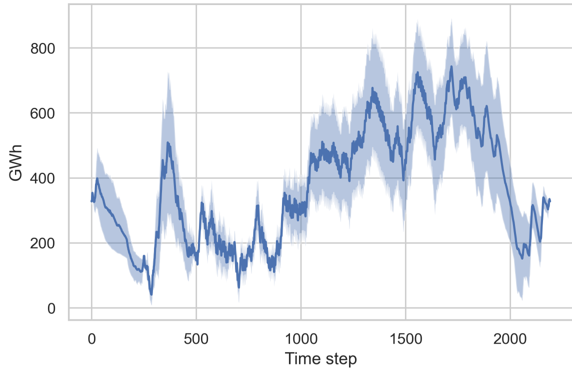

Figure 6.2: 2030 - potential exploration - dunkelflaute - storage behaviour.

6.2 2030 - Comparison of installed electrolysis capacities

Based on the range of potential for electrolysis capacity in 2030, the range for this series of experiments was determined. For every capacity, we determined the maximum regret for system costs, carbon emissions and loss of load. For each scenario, regret measures the difference between the outcome of the given capacity and the outcome of the optimal capacity for that scenario. The maximum regret for all capacities and weather years are subsequently given in Table 6.3.

The first and most obvious result is that in 2030, the electrolysis capacity does not affect the loss of load. This can be explained by the fact that in none of the scenarios hydrogen turbine installations were already constructed. Hydrogen does not yet act as a buffer for electricity in times of shortages, only in times of overshoot where residual electricity can be converted into hydrogen to reduce overall system costs. It should be noted that there are different values for loss of load between the scenarios, the capacity simply does not have any impact on those. Taking the mini-max regret approach, the capacity with the least maximum regret can be considered the most prudent for 2030. Following the results from the table, this is a capacity of 12 GW. A reduced capacity will lead to an increase in costs and carbon emissions, while an increased capacity does not have any further effect on the KPIs. In addition, using a deductive approach, we can determine if this capacity can still be considered most prudent if accompanied by an investment decision. Moving from 11 to 12 GW of capacity, a cost reduction of 92 MEURO is achieved in the worst scenario, resulting in the investment being amply recouped. Considering these considerable cost savings, investment in the most prudent capacity allows for a CAPEX of up to 1840 EURO/kW. This is considerably highly that the higher investment price for electrolyser stacks obtained from Table A.2, leading to an annuity of 27.5 per GW

In addition, the prudent capacity is based on a single configuration of input variables, while in reality, there is a high probability of other configurations occurring. Figure 6.3 shows the distribution of the regret values for the KPIs across the different installed capacities. With this figure, we can assess the viability of the prudent capacity in relation to other scenarios. The maximum regret of 92 MEURO and 180 kton CO_2 are depicted as outliers[1], thus showing their infrequent occurrence. The figure indicates that with an 11

[1] A data point with a value 1.5 times the interquartile range from the upper or lower quartile.

GW capacity, there is a significant probability of overinvestment, as the median cost regret is 0. For 10 GW, however, the median lies around 80 MEURO regret, still allowing room for significant investments.

Table 6.3: Maximum regret outcomes 2030.

			Capacity [GW]					
		Unit	**8**	**9**	**10**	**11**	**12**	**13**
Normal	Costs	MEURO	456	322	201	92	0	0
	CO_2	kton	946	619	322	190	0	0
	LoL	GWh	0	0	0	0	0	0
Dunkel-flaute	Costs	MEURO	461	327	206	94	0	0
	CO_2	kton	951	630	340	190	0	0
	LoL	GWh	0	0	0	0	0	0

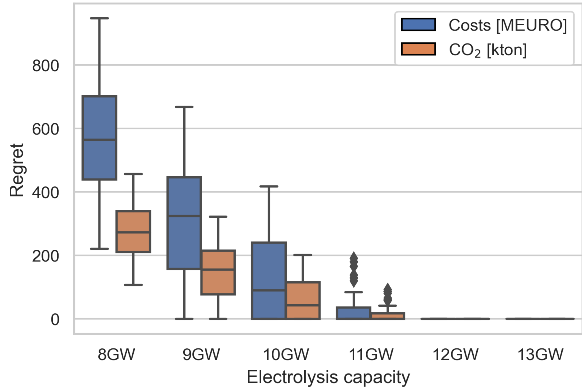

Figure 6.3: 2030 - capacity comparison - distribution of KPI regret values.

Moreover, the storage behaviour curves are almost identical to the potential exploration experiments, do not reveal much variation between capacities and are therefore not shown. The fact that an increase in electrolysis capacity barely leads to a difference in the behaviour of the storage indicates that the electrolysis capacity does not determine the filling rate of the storage. The storage can already adequately meet the supply-demand imbalance with a capacity starting at 8 GW, additional capacity will thus lead to an increase of hydrogen flowing directly into the market. At the same time, the number of time steps where the electrolysers operate at full load significantly differentiates over the different capacities, shown in Table 6.4 and Figure 6.5. An additional capacity of up to 9 GW leads to increased production during electricity overshoots while not heavily decreasing the full load hours. However, after this capacity, the full load hours significantly decrease. This behaviour is underlined in the figure, where 8 and 9 GW show no standard deviation in their full load hours, indicating that this capacity is utilised for about a quarter of the year in all scenarios. Nonetheless, beyond that capacity, we can see a steep increase in production only for a few hours per year, especially for 11 and 12 GW. This shows that investments in the last few gigawatts of capacity will know very limited production hours. Lastly, the average load of the electrolysers is, in all cases, below 40%, showing their dependency on peaks in residual load.

Figure 6.4: 2030 - capacity comparison - average electrolyser load.

			Capacity [GW]					
		Unit	**8**	**9**	**10**	**11**	**12**	**13**
Normal	Full load	N	528	455	274	151	1	0
	Avg load	GW	3.1	3.3	3.5	3.6	3.6	3.6
	Av. load	%	39	37	35	32	30	28
Dunkel-flaute	Full load	N	538	460	274	147	1	0
	Av. load	GW	3.1	3.3	3.4	3.5	3.6	3.6
	Av. load	%	38	36	34	32	30	27

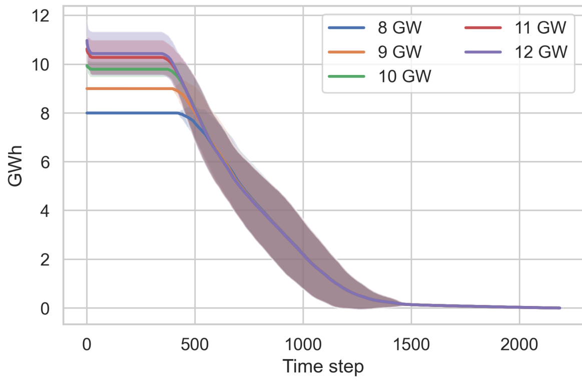

Figure 6.5: 2030 - capacity comparison - electrolyser load.

Furthermore, Figure 6.6 shows the percentage of renewable electricity allocated to electrolysis and the percentage of curtailment of VRES. Across the experiments, electrolysis consumes around 20 to 35% of the total renewable electricity supply on average in 2030. The addition of electricity capacity also has a role in reducing curtailment, preventing the disposal of carbon-free electricity. Up and until 10 GW of capacity, curtailment levels show a noticeable difference. However, due to the limited full load hours beyond 10 GW, we do not observe any eligible difference in curtailment or total consumption of VRES.

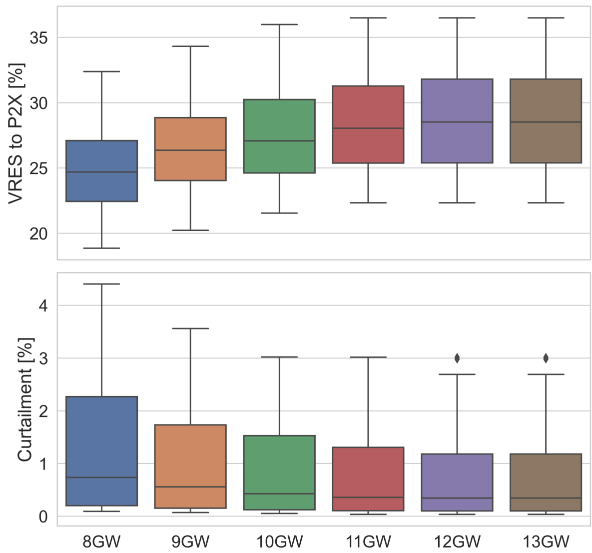

Figure 6.6: 2030 - capacity comparison - VRES to P2X and curtailment.

6.3 2040 - Exploration of the potential for electrolysis

Similar to the 2030 potential exploration, the capacity is left unrestricted for this experiment series. For both weather years, the maximum electrolysis level ranges from 24.70 to 33.93 GW, as shown in the heat map in Figure 6.4. For this refined heat map, two experiment variables have been left out; the installed hydrogen turbine capacity (H2T) and installed CCGT capacity (GAS). Differences in the values of these variables did not impact the maximum electrolysis level. For the hydrogen turbines, this is due to the presence of UHS. Increasing hydrogen turbine capacity impacts electrolysis only when storage production and injection levels are sufficient. In these experiments, limited injection and production rates constrained the influence of hydrogen turbine capacity on maximum electrolysis levels. Related to this is the absence of impact from installed CCGT capacity. CCGT provides peak power in times of renewable electricity shortages. In principle, this does not affect the maximum electrolysis level unless it is linked to the production levels of hydrogen turbines. Since that relationship is eliminated due to storage production limitations, this relationship also loses its impact. Moreover, the dunkelflaute year showed no differences in potential ranges and the relation between experiment variables. It is, therefore, not shown.

The refined heat map has been structured so that the policy levers, according to the XLRM-framework, are situated on the upper part of the table as configurations. Although treated as uncertainties in the model scheme, these factors possess the potential to turn into policy levers depending on the political agendas and level of intervention. The most influential variables are placed on the outer layers of tables and are formatted in the darkest colour tint. By closely observing this heat map, we see some noteworthy results:

- Of the three policy levers, offshore wind is the most dominant variable in determining the maximum electrolysis level. Interconnection is more influential than installed lithium-ion capacity because it has a longer temporal horizon regarding flexibility. Batteries tend to store sufficient electricity for daily variations. However, electrolysers act in the flexibility range of weeks to a month. In our model, interconnectors offer flexibility whenever the optimizer requires it, thus competing more with electrolysis.

- The electricity ratio of industrial heat demand only affects the maximum electrolysis level if the flexible capacity in the industry is also high. As the LCOH and LCOE analyses show, hydrogen will be more costly than electricity in 2030. Higher flexibility in the industry will thus lead to an overall higher demand for electricity. If the flexible industry capacity is low, changing the electricity ratio of industrial heat demand does not inflict a great enough change in demand to impact the potential for electrolysis. If this flexible capacity is high, the resulting demand change will thus be high enough to change the potential for electrolysis.

Table 6.4: 2040 - potential exploration - refined heat map of maximum electrolysis level.

					Wind-10				Wind-42			
					Inter-25		Inter-14		Inter-25		Inter-14	
					LiOn-10	LiOn-42	LiOn-10	LiOn-42	LiOn-10	LiOn-42	LiOn-10	LiOn-42
IH-l	EMB-h	Mob-l	Ind-flex-5	IH-e-53	34.7	34.7	37.25	37.25	37.25	37.25	37.25	37.25
				IH-e-33	37.25	37.25	37.25	37.25	37.25	37.25	37.25	37.25
			Ind-flex-2	IH-e-53	36	36	36	36	37.25	37.25	37.25	37.25
				IH-e-33	36	36	36.43	36	37.25	37.25	37.25	37.25
		Mob-h	Ind-flex-5	IH-e-53	36.56	36.56	36.56	36.56	39.11	39.11	39.11	39.11
				IH-e-33	36.56	36.56	39.11	39.11	39.11	39.11	39.11	39.11
			Ind-flex-2	IH-e-53	37.86	37.86	37.86	37.86	37.86	37.86	39.11	39.11
				IH-e-33	37.86	37.86	37.86	37.86	37.86	37.86	39.11	39.11
	EMB-l	Mob-l	Ind-flex-5	IH-e-53	35.85	35.85	38.4	38.4	38.4	35.85	38.4	38.4
				IH-e-33	38.4	38.4	38.4	38.4	38.4	38.4	38.4	38.4
			Ind-flex-2	IH-e-53	37.15	37.15	38.4	37.15	38.4	38.4	38.4	38.4
				IH-e-33	37.15	37.15	38.4	37.15	38.4	38.4	38.4	38.4
		Mob-h	Ind-flex-5	IH-e-53	39.54	39.54	39.54	39.54	42.09	42.09	42.09	42.09
				IH-e-33	42.09	39.54	42.09	42.09	42.09	42.09	42.09	42.09
			Ind-flex-2	IH-e-53	40.84	40.84	40.84	40.84	42.09	42.09	42.09	42.09
				IH-e-33	40.84	40.84	40.84	40.84	42.09	42.09	42.09	42.09
IH-h	EMB-h	Mob-l	Ind-flex-5	IH-e-53	37.54	37.54	37.54	37.54	40.09	40.09	40.09	40.09
				IH-e-33	40.09	37.54	37.54	37.54	40.09	40.09	40.09	40.09
			Ind-flex-2	IH-e-53	38.84	38.84	38.84	38.84	39.83	38.84	40.09	40.09
				IH-e-33	38.84	38.84	38.84	38.84	40.09	40.09	40.09	40.09
		Mob-h	Ind-flex-5	IH-e-53	39.41	39.41	39.41	39.41	41.96	41.96	41.96	39.41
				IH-e-33	39.41	39.41	39.41	39.41	41.96	41.96	39.41	41.96
			Ind-flex-2	IH-e-53	40.71	40.71	40.71	40.71	40.71	40.71	40.71	40.71
				IH-e-33	40.71	40.71	40.71	40.71	40.71	40.71	41.96	40.71
	EMB-l	Mob-l	Ind-flex-5	IH-e-53	38.69	38.69	41.24	41.24	38.69	41.24	41.24	41.24
				IH-e-33	38.69	38.69	41.24	38.69	41.24	41.24	41.24	41.24
			Ind-flex-2	IH-e-53	39.99	39.99	39.99	39.99	41.24	41.24	41.24	41.24
				IH-e-33	39.99	39.99	39.99	39.99	41.24	41.24	41.24	41.24
		Mob-h	Ind-flex-5	IH-e-53	42.38	42.38	42.38	42.38	44.93	44.93	44.93	44.93
				IH-e-33	42.38	42.38	44.93	42.38	44.93	42.38	44.93	44.93
			Ind-flex-2	IH-e-53	43.68	43.68	43.68	43.68	43.68	43.68	44.93	44.93
				IH-e-33	43.68	43.68	43.68	43.68	44.93	43.68	44.93	44.93

The results for the average LCOH of hydrogen are given in Table 6.5. When considering a lower investment cost of 400 EURO/kW, the hydrogen price is halved compared to 2030. Due to the large amounts of VRES installed and thus higher production of electrolysis, the system runs fewer operation hours on SMR with CCS and imports less, resulting in an overall lower marginal production price for hydrogen. However, if the electrolyser CAPEX rises, the difference compared to 2030 drops and the LCOH significantly increases. The average LCOE for 2040 in this experiment is 0.14 EURO/kWh, 0.09 EURO/kWh less than 2030. This is due to the system's higher influx of low-cost renewable electricity.

Table 6.5: 2040 - potential exploration - average LCOH.

Electrolyser investment costs		**LCOH**	
Total	**Annuity**		
EURO/kW	**MEURO/y**	**MEURO/GWh**	**EURO/kg**
0	0	0.03	0.87
400	20	0.06	2.15
600	30	0.08	2.79
800	40	0.10	3.43
1000	50	0.12	4.07
1200	60	0.14	4.71

The storage levels throughout the optimization periods, displayed in Figures 6.7 and 6.8, show slightly different behaviour from 2030. Despite still acting as a mid-term storage medium, a more apparent seasonal pattern can be seen with cycles in the 50-200 time step (week-month) range. A pattern that is also visible in levels of Dutch gas storage facilities. UHS acting more as a seasonal buffer can be accounted for by considering the phase-out of natural gas. Typically, gas storage owes its seasonal role to the increased heating demand in the winter. Most of the current Dutch heat supply, predominantly in the built environment, is supplied by gas. By 2040, a large proportion of the built environment will have switched to electric heat generation through, for example, heat pumps or floor heating. This will result in a seasonal electricity consumption pattern in the built environment with peaks during the winter. As wind and solar PV are complementary in terms of generation over the year (wind produces more in winter, while solar produces more in summer), less electricity will be available for electrolysis in winter. Moreover, flexibility must be present to deliver extra electricity during the winter. Next to the nuclear and a smaller amount of gas CCGT being present in some scenarios, electricity generation through hydrogen CCGT or OCGT will have a more principal role in the system. The spike in built environment heating demand around time step ± 3500 (Figure B.1) takes its toll on the level of UHS, clearly showcasing this direct relation. In the dunkelflaute weather year, the effect of the prolonged period with reduced VRES generation can be seen during time steps ± 200-300. In this period, the UHS is filled to the minimum for about two weeks due to the dunkelflaute.

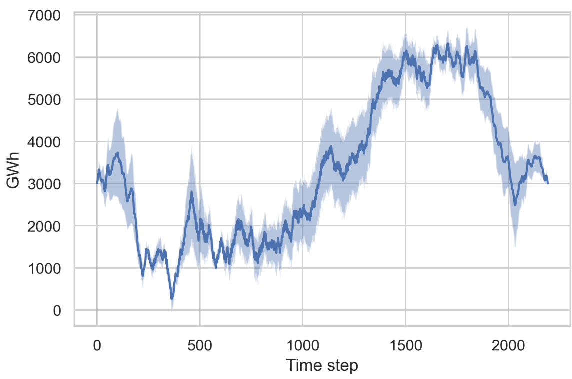

Figure 6.7: 2040 - potential exploration - storage behaviour

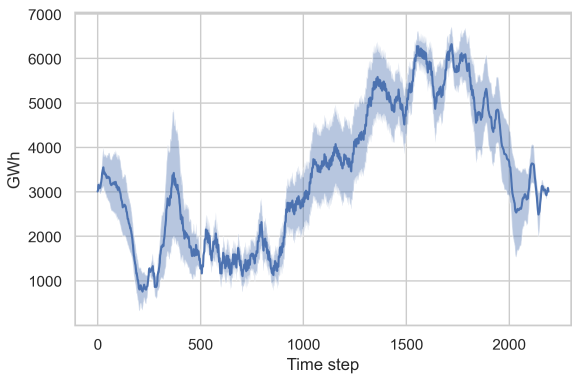

Figure 6.8: 2040 - potential exploration- dunkelflaute - storage behaviour

6.4 2040 - Comparison of installed electrolysis capacities

For this series of experiments, 6 different capacities between 34 and 44 GW are compared based on the results of the potential exploration series. The maximum regret results on each capacity's KPI are displayed in Table 6.6. The first thing that can be noted is that expanding the electrolysis capacity yields a positive effect on reducing the loss of load, in contrast to the experiments conducted for 2030. If a capacity of 34 GW instead of 38 GW is adopted, the loss of load increases up to 7.56 GWh in the worst scenario. When investment costs are not considered, 44 GW is the most prudent capacity for 2040. It does not have any regret in all the scenarios that were optimized. However, the difference in regret between the other capacities is significantly lower than for 2030. When weighing an electrolyser CAPEX of 20 MEURO per GW, a different, most prudent capacity can be concluded, namely 38 GW. Solely based on costs, this number capacity would have been 38 GW. However, the first criterion of a prudent capacity in this work is that it maximises contribution to the security of supply. Every capacity below 38 GW is not able to comply with this criterion. Furthermore, exceeding a capacity of 38 GW will not result in reduced carbon emissions. Instead, it will solely contribute to cost reduction.

The level of risk aversion of this prudent capacity can be determined by assessing the distribution of regret across the KPIs in Figure 6.9. In the figure, we can see that the regret on which this prudent capacity is based primarily consists of infrequent outliers in the experiments. The prudent capacity is only justified in a handful of scenarios, resulting in a high probability of overinvestment. If the policymakers seek to find a capacity with the highest chance of being optimal without overinvestments, the optimal capacity could be lower than the 34 GW analysed in this experiment. However, 38 GW remains the most prudent capacity across all scenarios.

Table 6.6: Regret outcomes 2040.

			Capacity [GW]					
		Unit	**34**	**36**	**38**	**40**	**42**	**44**
Normal	Costs	MEURO	81.1	38.6	17.6	6.6	2.4	0
	CO_2	kton	245	132	40	0	0	0
	LoL	GWh	7.56	0.26	0	0	0	0
Dunkel-flaute	Costs	MEURO	131	88	51	26	9	0
	CO_2	kton	245	132	40	0	0	0
	LoL	GWh	7.56	0.26	0	0	0	0

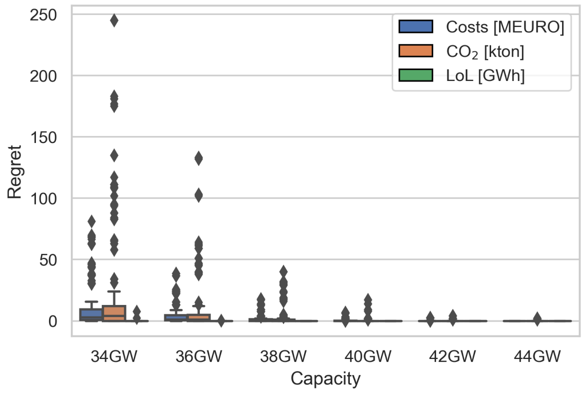

Figure 6.9: 2040 - capacity comparison - distribution of KPI regret values.

Similar to 2030, the electrolysis capacity has a limited impact on the level of the UHS. Therefore, these results are not shown. However, a significant difference in the average load and number of time steps with full load can be observed (Table 6.7). In 2030, the lowest capacity analysed led to 528 or 538 full load time steps, while in 2040, this is 123 or 133 (normal vs. dunkelflaute). Figure 6.10 shows that the different electrolyser capacities follow a similar load curve for approximately 90 % of the optimization year. The differences in regret and, thus, KPI output values are realised in the remaining 10%. 44 GW was excluded from the figure since no visual distinction could be made compared to the 42 GW load curve. In addition, the electrolyser's average load is considerably lower compared to 2030, reaching values between 20 and 26%.

Table 6.7: 2040 - capacity comparison - average electrolyser load.

			Capacity [GW]					
			34	**36**	**38**	**40**	**42**	**44**
Normal	Full load	N	123	82	44	16	7	0
	Av. load	GW	8.8	8.8	8.8	8.8	8.8	8.8
	Av. load	%	26	24	23	22	21	20
Dunkel-flaute	Full load	N	133	93	50	20	9	0
	Av. load	GW	8.8	8.8	8.8	8.8	8.9	8.9
	Av. load	%	26	24	23	22	21	20

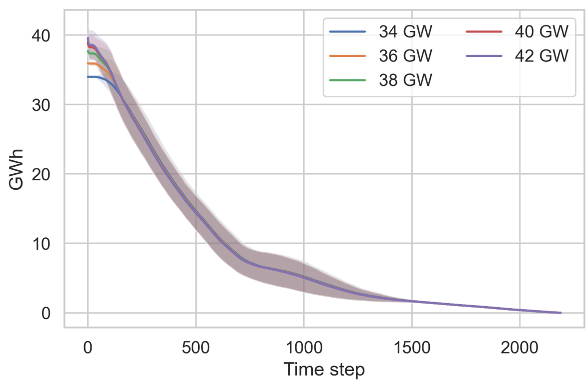

Figure 6.10: 2040 - capacity comparison - electrolyser load.

Lastly, the fraction of renewable electricity allocated to electrolysis and curtailment can be found in Figure 6.11. As a result of the minimal difference in the load curves of the different capacities, there is a minimal difference in the VRES consumption of the electrolysers. The overall electricity consumption knows little difference; thus, the share of VRES consumed also hardly varies. A slight difference is observed in the curtailment rate of renewable electricity. Considering the weight of this difference, it can be concluded that the impact on curtailment is minimal, given the current capacity levels. However, if the analysed capacities were lower, the results might have demonstrated a more significant impact.

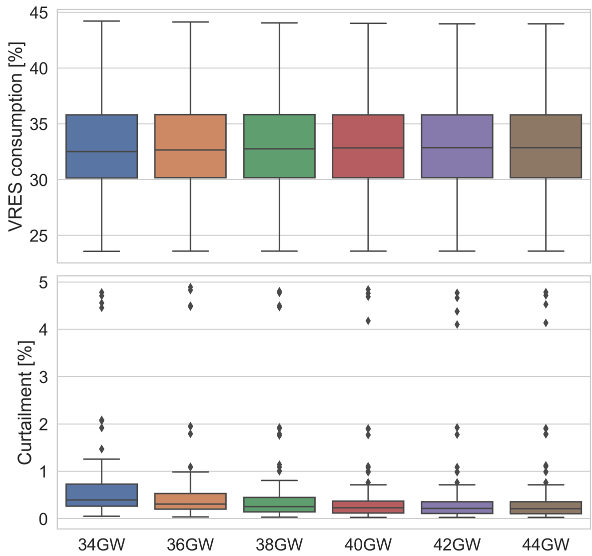

Figure 6.11: 2040 - capacity comparison - VRES to P2X and curtailment.

6.5 2040 - Investments in electrolysis capacity

In this series of experiments, an investment function based on the annuity of an electrolyser stack is included. Based on the small literature review conducted in Appendix A, an annuity of 4 MEURO per 200 MW of electrolysis capacity is determined. As some of the data from this literature review is solely based on the actual costs of an electrolyser stack, it could occur that, in reality, the investment costs of an electrolyser will be higher. For this reason, we conducted two additional validation runs with 1.5 and 2 times the CAPEX, 600 and 800 EURO/kW (6 and 8 MEURO/200MW). The ranges of installed capacity that result from these runs can be found in Figure 6.12. We see reduced investment over the scenarios by increasing the investment costs per electrolysis stack. Nonetheless, doubling the CAPEX does not result in significant decreases, staying within a reduction of 2 - 3 GW.

In addition, the outcomes for LOCH are compared with those of other experiment series in Table 6.8. The experiment runs with a built-in investment decision yield lower LOCH results than the post-optimization determination of LCOH for the exploration experiments series of 2040. These results can be explained by comparing the ranges of maximum electrolysis levels in both experiments. In the investment series, Linny-R has more information to optimize for lower costs and thus has multiple scenarios with maximum electrolysis levels below the lowest value of the exploration experiment. A result is fewer costs for investments and consequently lower levelised costs of hydrogen. Regarding LOCH determination, the investment decision experiments thus create a more realistic estimation in terms of cost establishment. Secondly, we see a price reduction of more than half from 2030 towards 2040. This can be explained by the increased generation by VRES, which is considered cost-free in our model. As a result, more hydrogen can be produced with electrolysis instead of SMR with CCS.

Furthermore, altering the CAPEX did not culminate in differences in relationships among the experimental variables, both in terms of their linear correlation with the outputs and their interrelationships with each other. For this reason, the remainder of the analyses for this experiment series regarding the relation of the uncertainties are conducted with a CAPEX of 400 EURO/kW.

The capacity comparison experiments created insights into a prudent capacity for all scenarios. However, by incorporating an investment decision, we can create insights in which uncertainties determine the level of investment and, thus, the prudent capacity. Hereafter we will discuss the results of the relationship between uncertainties and the capacity for electrolysis. With an analysis of the heat map of the maximum electrolysis levels, insights can be gained into the relations among experiment variables. Unlike the other series of experiments, this heat map showed variation in the output of every experiment variable, resulting in a substantial table that can be found in Appendix E. In addition, a correlation analysis was conducted to show the direct relation of the experiment variables to the installed electrolysis capacity. The higher the correlation, the more critical the experiment variables. Negative values indicate a negative relationship. The results can be found in

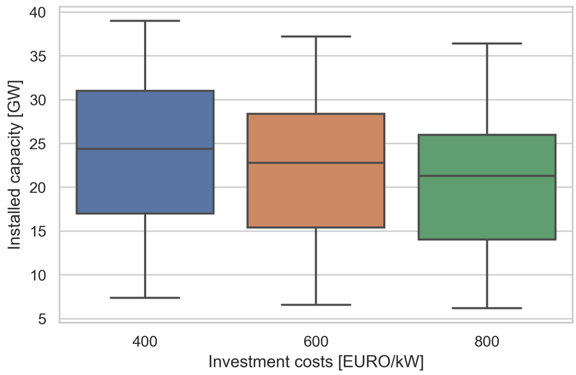

Figure 6.12: 2040 - investment decision - distribution of installed electrolysis capacity for three CAPEX values.

Table 6.8: Comparison of average LCOH results from different experiment series.

Investment costs	2030 exploration	2040 exploration	2040 investment decision
EURO/kW	EURO/kg		
400	4.79	2.15	1.69
600	4.99	2.79	2.01
800	5.18	3.43	2.31

Table 6.9. Lastly, Figures 6.13, 6.14 and 6.15 give the relation between flexible capacity, hydrogen demand and maximum residual load and the installed electrolysis capacity, respectively. Flexible capacity entails not only the flexible industry capacity but all forms of flexibility in conventional generation, storage, interconnection, hydrogen turbines and industrial flexibility. The red regression line indicates the correlation between hydrogen demand and investment in electrolysis capacity. The steeper the line, the more significant the relation. A combination of these analyses led to some noteworthy results:

- The scenario with the lowest investment of 7 GW is significantly lower than the lowest potential for capacity of 34.70 GW. In the scenario where 7 GW of capacity is invested, the peaks in renewable electricity supply did not generate sufficient returns, so no further investments were made. On the one hand, if this capacity is adopted in the scenarios where Linny-R invests 39.60 GW, significant cost reductions could have been achieved but were wasted instead. On the other hand, installing a prudent capacity of 38 GW would have led to significant overinvestment in this scenario.

- Some scenarios show investment in electrolysis that is greater than 34 GW. This can be explained by the fact that the number of input variables varied in this series of experiments is greater than in the capacity comparison series. The experiment variables excluded have a different base value than the high and low values in the experiments.

- The installed capacity of offshore wind has a negative correlation with the investment in electrolysis. In general, this is due to the fact that there is a lower base generation of VRES. For this reason, peaks in generation are more important and electrolysis needs to invest more to utilise these peaks fully. However, if the industrial heat and mobility demand are both high, this effect is reversed and the correlation becomes positive. In this scenario, the demand for hydrogen is at the highest level across the scenarios. The extra capacity of offshore wind allows investments to reduce the use of SMR with CCS. If the offshore wind capacity is then lower, additional investments will not be able to produce sufficient hydrogen and the optimizer chooses to produce with SMR with CCS.

- Unexpected behaviour occurs in the combination between mobility demand and electricity ratio. A low mobility demand with a high electricity ratio leads to higher investments in electrolysis compared to the lower electricity ratio. However, this effect is reversed if the total mobility demand is also high. This can be explained by the fact that in the first scenario, the higher electricity ratio will result in less consumption of oil-based fuels and, thus, less hydrogen consumption by refineries. If the total mobility demand then also grows, the electricity demand will increase to the extent that there will be less electricity available for hydrogen production.

- Although there is a strong correlation between the flexible industry capacity and the investment in electrolysis, only a minimal relation can be found to the total flexibility capacity in the system in Figure 6.13. This can be explained by the fact that the other flexibility options, as also seen in the correlation table, have a minimal influence on the investment in electrolysis capacity. Flexible industry capacity is the only flexibility option that significantly influences the demand for electricity or hydrogen, depending on the scenario. As we can see in Figures 6.14 and 6.15, these factors predominantly determine the investment in electrolysis. Hydrogen CCGT also consumes hydrogen (between 10-20% of total demand); however, previous experiments showed that its influence on electrolysis is limited due to the underground hydrogen storage.

- Uncertainties influencing the hydrogen demand have a more significant effect on the prudent capacity than uncertainties influencing the maximum residual load (or, in other words, the availability of electricity).

Table 6.9: 2040 - investment decision - correlation of experiment variables

	Correlation
Energy demand mobility	55%
Industrial heat demand	52%
Electricity ratio of energy demand mobility	26%
Installed capacity offshore wind	(-)26%
Flexible industry capacity	(-)24%
Lithium-ion storage capacity	(-)22%
Electricity ratio of industrial heat demand	17%
Installed capacity CCGT	(-)6%
Interconnection capacity	(-)1%
Installed capacity hydrogen CCGT	1%

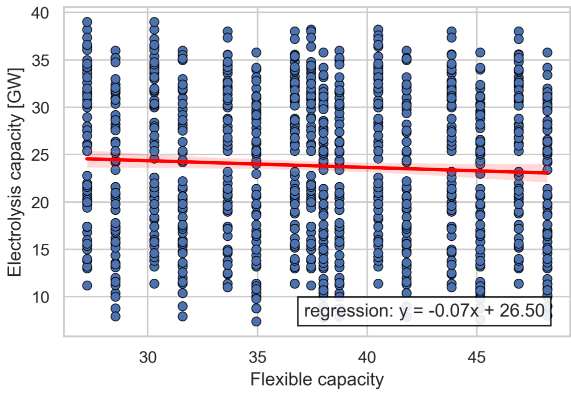

Figure 6.13: 2040 - investment decision - flexible capacity vs. maximum electrolysis capacity.

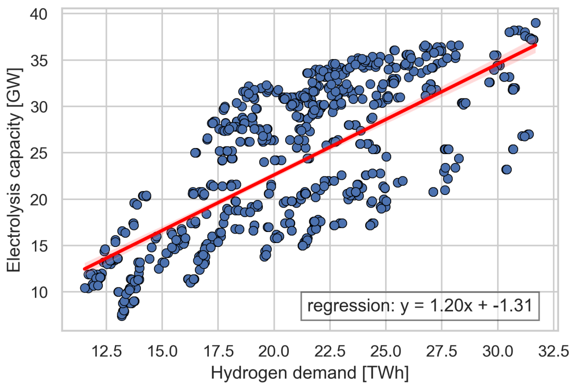

Figure 6.14: 2040 - investment decision - hydrogen demand vs. maximum electrolysis capacity.

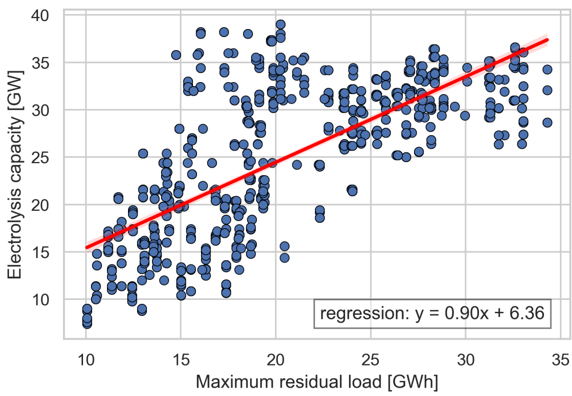

Figure 6.15: 2040 - investment decision - maximum residual load vs. maximum electrolysis capacity.

6.6 2040 - The dependency of electrolysis potential on hydrogen storage

In this last series of experiments, it is not the electrolysis capacity being varied and compared, but the number of underground hydrogen storage facilities, each sized 200 GWh. By leaving the electrolysis capacity unrestricted, the outcomes will show us to what extent the number of storage facilities influences the maximum electrolysis capacity in the system. The variation in the number of storage facilities is from 26 to 46, with steps of 2 for the normal rate and from 26 to 36 for the double rate. Double rate entails a doubling from the normal injection (1 GWh/h) and withdrawal (1.2 GWh/h) to 2 (GWh/h) and 2.4 (GWh/h), respectively. Figure 6.16 displays the results on the average maximum electrolysis capacity utilised for each run, with the standard deviation as error bars. The most important outcome is the relation between the injection and withdrawal rates and the maximum electrolysis capacity. Doubling the rates almost leads to a doubling in the potential for electrolysis capacity when 26 salt caverns are installed. As the storage capacity grows, this ratio slowly decreases.

A fraction can be determined to properly determine the relation by which the total storage capacity influences the electrolysis capacity. Figure 6.17 gives the fraction expressed in GW electrolysis per (extra) 100 GWh of storage capacity for the normal and double rates. The line is the average across all scenarios and the shadow is the standard deviation. In the experiments where normal injection and withdrawal are considered, the fraction between storage and electrolysis circles around 0.5 $GW_{electrolysis}/100GWh_{capacity}$. Meaning that adding an extra 100 GWh of storage capacity will increase the potential for electrolysis with ± 500 MW. The greater the total capacity becomes, the greater differences in this fraction across the scenarios. However, this relation significantly changes when the injection and withdrawal rates are doubled. For capacities ranging from 26 to 28, the fraction is nearly 1, but after reaching 38 storage units, or 7600 GWh of storage capacity, adding additional storage does not affect the potential for electrolysis, on average.

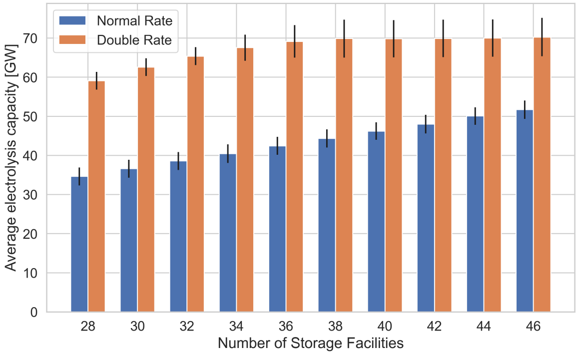

Figure 6.16: 2040 - storage dependency - electrolysis capacity with different injection and withdrawal rates.

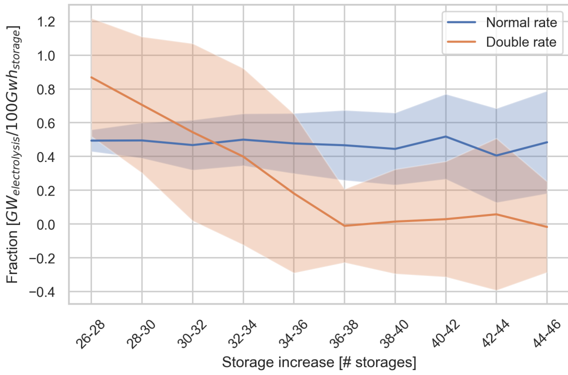

Figure 6.17: 2040 - storage dependency - relation between storage capacity and electrolysis capacity.

Figures 6.18 and 6.19 give the storage behaviour for both the rates and the compared storage facilities. The storage does not change behaviour when the total storage capacity is increased or decreased. A difference can only be found in the total throughput of the storage over the optimization period. As the capacity increases, so does the storage level, yet the underlying pattern remains unchanged. Although having a considerable effect on the potential for electrolysis, the effect of the injection and withdrawal rates on the storage behaviour is minimal. This can be explained through the concept of complete foreknowledge in optimization. In every scenario, the optimizer utilises the storage in the most optimal way to minimize costs. Increasing the capacity thus leads to this same optimal pattern but with a higher filling rate. Increasing the injection rate leads to the same pattern but with steeper increases and decreases in the curve.

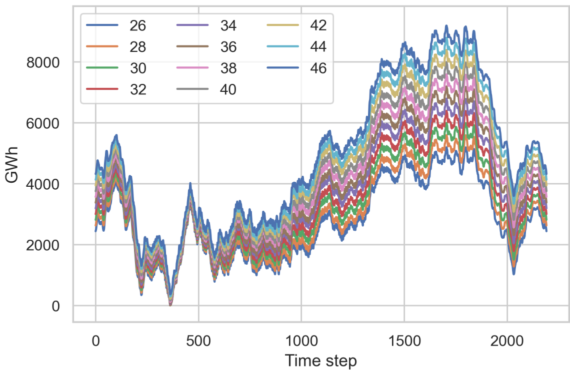

Figure 6.18: 2040 - storage dependency - normal rate - storage behaviour.

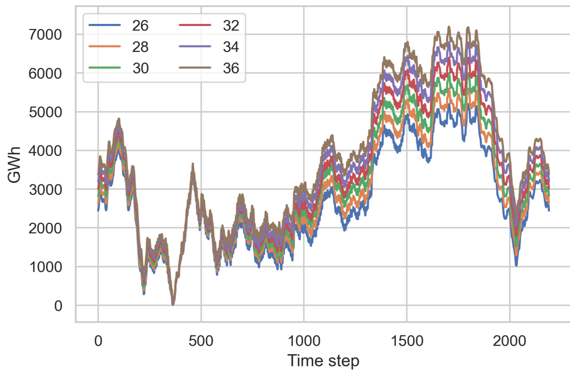

Figure 6.19: 2040 - storage dependency - double rate - storage behaviour.

Chapter 7

Discussion

In this chapter, we will critically analyse and interpret the results produced in this research. This includes reflecting on the possible limitations of this work and giving recommendations for both policy and further research.

7.1 Interpretation of results

In this section, the results of the experiments will be interpreted in three separate subsections. First, the results for 2030 and 2040 will be individually interpreted after which the relation to the storage is discussed.

7.1.1 Interpretation for 2030

The experiments conducted in 2030 aimed to explore the potential for electrolysis capacity while subjecting the system to various ranges of uncertainty. The first and foremost result is the maximum potential for electrolysis capacity over 1024 different scenarios and two weather years of 8.77 to 13.09 GW. Even in the least fruitful scenario for electrolysis, enough electricity is available to create 8.77 GW of hydrogen for ± 1200 hours a year, amounting to 11.68 GW of renewable electricity. To put this into perspective, this overshoot amounts to approximately half of the total current electricity supply in the Netherlands (June 2023) [14]. With the extensive roll-out of offshore wind and solar PV, significant levels of renewable electricity will thus be fed into the system. The results have shown that, over the different scenarios, 19-36% of the yearly renewable electricity supply is consumed by hydrogen production, with electrolysis capacity being able to reduce curtailment marginally. The Dutch government's current ambition for electrolysis capacity is 3-4 GW. Interpreting these results show us that enough renewable electricity will be available to raise this target. If this is not possible due to, for example, technical or material limitations, additional electrification or other forms of flexibility should be pursued. If not, it will lead to large amounts of valuable carbon-free electricity having to be curtailed and, thus, significantly more carbon emissions.

Moreover, the most prudent electrolysis capacity for 2030 is 12 GW, both with and without taking investment costs into consideration. From a system perspective, this capacity will result in the least regret in the worst scenario when it comes to costs and CO_2 emissions, and adding capacity will in no scenario lead to more cost or emission reduction. As it is based on the worst scenario, this capacity is the most robust capacity policy-makers can aim for. However, the probability of a scenario occurring where 12 GW leads to overinvestment is ± 75%. Adopting a system perspective and targeting a lower electrolysis capacity helps mitigate the risk of overinvestment, which can be considered beneficial from a societal standpoint. If the realisation of the final gigawatts of capacity necessitates subsidies, overinvestment will eventually be traced back to the consumer. A risk-averse approach in terms of overinvestment is to aim for 9 GW of electrolysis capacity for 2030, leading to overinvestment in a minimal 6% of the scenarios. However, this approach also raises the likelihood of underutilising the potential for green hydrogen production, ultimately leading to higher overall system costs and can thus not be considered prudent.

These insights are all based on a system perspective when determining the costs and emissions. An essential factor in the development of electrolysis is the business case it provides to profit-seeking companies. Several reports have been published presuming that hydrogen needs at least 50% of full load hours to become competitive [53, 59, 44]. The system perspective-based prudent capacity of 12 GW obtains an average load of 30% and only reaches full load one time step a year, according to the results from this work. This is accompanied by an LCOH ranging from 0.15 to 0.17 MEURO/GWh (or 4.79 to 5.57 EURO/kg), depending on the investment costs of an electrolyser. A lot of the capacity installed will only be utilised in times of significant overshoots. To be more specific, when 12 GW of electrolysis capacity is installed, the last gigawatt of production will, on average, be producing a total of 60 GWh divided over 430 hours a year. Table 7.1 gives the margins that need to be realised in order to recoup this investment in the last gigawatt, rounded to half integers. To make this possible, a combination of extremely high hydrogen market prices and low electricity prices is necessary. Currently, however, the electricity market prices often drop below zero when there are overshoots of renewable electricity and the current hydrogen market price lies around 10 EURO/kg [120]. From an operator perspective, this last GW will most likely be a non-recoupable investment, although offering system-wide cost reduction in the worst scenarios. With an installed capacity of 9 GW, the margins required to recoup the investments are considerably smaller and significantly more compelling for market-based investments.

Table 7.1: Margins required for last GW of electrolysis capacity in 2030.

Investment costs		400	800	1200	EURO/kW
Average margin required	**12 GW**	11.00	22.00	33.50	EURO/kg
	9 GW[1]	1.50	2.50	4.00	EURO/kg

[1] Based on 500 GWh production divided over 1850 hours.

7.1.2 Interpretation for 2040

Looking towards 2040, the potential for electrolysis has significantly grown, with a range from 34.70 to 44.93 GW observed. This substantial potential for electrolysis, however, comes with a significant consumption of 24-44% of the total renewable electricity supply, emphasizing the integral role of hydrogen in shaping our future Dutch energy system. Even in the scenarios where electrolysis shows the lowest potential, there will still be more than 10 GW of electricity available after meeting the base load demand for ± 2900 hours per year. To prevent significant loss of valuable electricity, it is therefore essential to note that any form of electrification and flexibility is critical, the large-scale deployment of green hydrogen production is a prime example. This result lays the basis for all results and recommendations. As a secondary conclusion, it is evident that there is potential to construct several dozen gigawatts of electrolysis between 2030 and 2040. Common doubts have arisen in the public debate about whether the over-stimulation of electrolysis for 2030 will not lead to overinvestment in 2040. The construction of vast quantities of electrolysis capacity should not lead to unused production plants by the time we reach 2040. The results from this analysis show that this is not the case and that even if the ambition for 2030 is surpassed, it will prove itself a useful addition to the Dutch energy system in terms of cost-, emission- and loss of load reduction

Furthermore, 38 GW is the most prudent capacity for electrolysis in 2040. This capacity ensures maximum impact on the security of supply, carbon emissions and costs, with increased capacity leading to overinvestment in all scenarios. However, as it is based on the worst scenario, 38 GW capacity leads to overinvestment in 97% of the scenarios analysed. In the capacities compared for this experiment, a non-regret option in terms of overinvestment is not found. When aiming for a more risk-averse capacity of 34 GW, overinvestment still occurs in 75% of the scenarios. With this capacity, however, loss of load could increase up to 7.56 GWh. The size of the buffer is then limited by the by the level of electrolysis and the storage becomes depleted before shortages of electricity have passed, ultimately resulting in loss of load. Ensuring security of supply thus comes at a high risk of installing capacities that end up unused. Mitigation of loss of load by the implementation of other flexibility technologies ensures that this relation is diminished. This will result in a lower capacity being considered the most prudent. From a societal perspective, this is beneficial, as the minimum regret can be achieved with less risk of overinvestment. For policymakers, this enhances societal support. In addition to this, the last 2 GW of capacity of 38 GW will be operational for approximately 520 hours, producing 125 GWh. For investors being able to recoup their investments in these capacities, significant margins are required. These margins compared to the market price for 34 and 38 GW are shown in Table 7.1.

The question thus is whether a prudent capacity, as defined in this work, can be considered prudent from a social perspective. On the one hand, there is a great risk of overinvestment and insufficient incentive to invest for the market parties. To realise the latter, some form of subsidies or governmental intervention must be performed, resulting in higher societal costs. On the other hand, a lower capacity increases the risk of loss

Table 7.2: Margins required for last 2 GW of electrolysis capacity in 2040.

Investment costs		400	800	1200	EURO/kW
Average margin required	**38 GW**	11.00	21.50	32.00	EURO/kg
	34 GW[1]	6.50	13.50	20.00	EURO/kg

[1]Based on 200 GWh production divided over 640 hours.

of load. If the Dutch government successfully implements supplementary measures to address this loss of load, the prudent capacity for electrolysis could turn out to be significantly lower, thereby lowering the risk of excessive investment. Consequently enhancing the industrial support of the deployment of electrolysis.

As highlighted above, a prudent capacity does not imply that this capacity is the most optimal in all scenarios. Results have shown that with an investment decision, the optimal electrolysis capacities range from 7.00 to 39.60 GW. The ranges of the input variables, as displayed in Appendix D, have proven that there is great variation among the different scenarios that attempt to predict the future Dutch energy system. This uncertainty makes it considerably difficult for policymakers to shape their policy framework accordingly. By integrating an investment decision-based experiment, results were generated that gave insights into the most critical uncertainties determining the significance of electrolysis. This aids policymakers in recognizing the scenario they expect to face and determining the suitable capacity that corresponds to it:

- The total capacity of other flexibility options, such as interconnection, lithium-ion or CCGT capacity does not have a direct relation to investments made in electrolysis. Increased flexibility in other sectors of the Dutch energy system does not harm the potential for electrolysis. Policies for the stimulation of overall flexibility and electrolysis can thus be implemented alongside each other, depending on the policymakers' ambitions. By investing in flexible capacity to increase the security of supply, a lower prudent capacity for electrolysis could be realised.

- When considering either availability of electricity or the demand for hydrogen, it is the latter that has a more significant influence in the determination of a prudent capacity for electrolysis. When solely observing the relationship between these factors, every additional TWh of hydrogen demand enables, on average, 1.2 GW additional capacity of electrolysis. An extra GWh of peak residual load, on the other hand, enables roughly 0.9 GW of additional capacity. It is important to note, however, that this goes beyond the variables considered in this research. There are many other aspects, either not included in the experiment design or the model as a whole, that impact hydrogen demand and peak residual load. For all these aspects, the same underlying correlation applies and should therefore be considered in shaping Dutch policy.

- Increased offshore wind in combination with a low energy demand leads to a lower optimal capacity for electrolysis in the Netherlands. As the overall VRES generation is higher, there is less need to be reliant on the extreme peaks in generation and thus investments for those moments remain absent. However, this phenomenon disappears when the total energy demand increases. With the current plans of the Dutch government to ensure 50 GW of offshore wind capacity by 2040, it is thus advisable to monitor the development of energy demand in determining their target electrolysis capacity for 2040.

7.1.3 Interpretation on the relation between storage and electrolysis potential

Underground hydrogen storage consistently adhered to a mid-to-long-term cycle pattern throughout the experiments. The reason for the long-term seasonal pattern can be traced back to the built environment stepping away from gas and filling this gap mainly through electrification. As this demand follows a strong seasonal pattern, electricity demand will thus be higher in winter and less electricity will be available for hydrogen production. This is the opposite of the current functioning of gas storage, which is led by the increasing consumption of natural gas in winter. In this case, it is the supply of electricity that dictates the need for storage. In addition, as a result of this pattern driven by the built environment, electricity shortages intensify in winter, which consequently amplifies the necessity for hydrogen in electricity generation. This same functionality explains the mid-term role of storage, supporting week-to-monthly fluctuations during the periods when green hydrogen production is stalled as a result of low wind and solar production factors and the demand for hydrogen persists. During shortages of electricity, hydrogen storage together with hydrogen turbines can be used as a mid-term buffer to support the security of supply.

Furthermore, this mid-to-long-term cycle pattern of UHS is hardly affected by its own total capacity and the total capacity of electrolysis installed in the system. It is instead the electricity demand of the built environment and weather patterns that dictate the filling rate. On the contrary, enlarging the storage capacity, especially the injection and withdrawal rates significantly increases the electrolysis potential. This phenomenon occurs because, during the peaks of VRES generation, electrolysers have the capability to produce a larger quantity of hydrogen and feed it into storage when the demand is already met. Storage then fills a strategic role in reducing the overall costs of the hydrogen supply. For every 100 GWh of storage capacity, 0.5 GW of electrolysis capacity can be added to the system.

These results indicate the non-criticality of storage from a system perspective. With less storage, the system still functions and fulfils all demand. There thus is no need for major investments in storage early in the transition. However, as it positively influences the potential for electrolysis, storage can be used as a policy instrument to enhance market-based investments in electrolysis. Providing storage facilities to market parties to eliminate their investment costs, similar to the current design of natural gas storage, stimulates the hydrogen economy and creates a more fruitful environment for investment. Moreover, market parties could then use this storage to strategically deal with volatility in supply and reduce overall costs. Although not serving as the primary purpose, this will result in an additional hydrogen reserve, guided by the market.

However, these results are all based on a system with still operational SMR installations with CCS. In this case, storage is not the only medium for flexibility in meeting hydrogen demand. If policies are implemented banning the use of natural gas for hydrogen production, even with CCS, storage will become more essential to the system as the hydrogen supply with be dependent on weather conditions combined with imports.

7.2 Limitations

The limitations of any research are essential to acknowledge and address, as they provide valuable insights into the scope and potential constraints of the study. In this section, we explore and discuss the specific limitations encountered during the course of this master thesis, shedding light on areas that could have affected the study's outcomes.

The first significant limitation lies in the exclusion of the grid infrastructure from the model. Instead, a simplified copper plate approach was employed to estimate the prudent electrolysis capacity. This omission of the grid's dynamics and constraints could potentially impact the accuracy and feasibility of the results produced in this work. If grid constraints are incorporated into the electricity system, it will result in varying availability of electricity across different locations in the Netherlands. This discrepancy arises due to limitations on grid capacity and varying production and demand over different regions. Consequently, certain areas will have a higher potential for electrolysis than others. This could, in turn, result in an overall difference in the total prudent capacity in the Netherlands. Closely related to this is the behaviour of the underground hydrogen storage. In our model, all electrolysers can feed their production in one large storage facility. In reality, however, it could occur that not all electrolysis production plants are connected to this storage or specific storage units are reserved for specific electrolysers. This could lead to an entirely different filling pattern depending on the function of the storage. E.g. as a seasonal buffer or as a buffer for electricity supply.

Secondly, a limitation that can be identified is the dynamic role of import and export in the Dutch electricity system, especially towards 2040. The price for import in our model is assumed to be above the costliest generation assets in the Netherlands. In this way, it serves as a flexibility option in times of a shortage in domestic supply. In reality, however, the level of import will equally be determined by the availability, and thus price, of electricity in neighbouring countries. Such mechanisms can give rise to scenarios where importing electricity becomes more cost-effective than activating domestic generation assets. This influx of imported electricity into the system can increase the overall availability of electricity, potentially creating more potential for electrolysis. On the other hand, as the model only considers marginal production costs, the export level is minimal. If dynamic export prices and quantities are adopted, situations may arise where it is, on a system level, more cost-effective to export electricity rather than to convert it to hydrogen. This oppositely leads to a reduced potential for electrolysis. Moreover, this train of thought extends to the exportation of hydrogen, producing a reversed effect. In our work, the external demand for hydrogen is left out of the scope. There is a possibility that the Netherlands will serve as a European hydrogen production hub, generating significant quantities of hydrogen intended for export, much like Dutch refineries' role in the European oil-product supply. Consequently, this would drive up the demand for hydrogen, thereby creating more potential for electrolysis. Export and import, however, are dynamic mechanisms reacting to market prices. They are considerably complicated to model and are therefore additionally discussed in the recommendations for further research.

A third limitation can be found in the level of flexibility included in the model. As discussed in the interpretation of the results, flexibility will become increasingly important as the energy transition progresses. The flexibility options on the demand side considered in this research are fuel switching and up/down scaling in the industry and two different forms of storage. Towards 2040, the energy system will know much more and more complex forms of flexibility that have been excluded from the model. Examples of this are demand response in households through, for example, the emerging dynamic electricity contracts and EVs with energy management software planning their charge cycles. Due to this implication, the results may differ in terms of load loss and availability of electricity at peak times.

Furthermore, the pricing of electricity in the model is built upon the concept of marginal costs of generation. With the integration of a significant share of VRES, batteries trading short-term power and other forms of flexibility, this concept will no longer be sufficient to determine the electricity market prices. Instead of generation with renewable energy sources, it will most likely be the batteries and other flexibility technologies that set the market price based on their willingness to pay (or get paid). The exact establishment of the future electricity price is incredibly complex. However, it is inevitable that it will undergo a drastic change. For this reason, the merit order in the electricity system could transform and different revenues could be generated than currently implied in the model.

7.3 Policy recommendations

Interpreting the research results has brought forward several possible improvements or shortcomings of the current Dutch policy agenda. In this section, recommendations will be given to the Dutch national government on how the policy framework can be improved to support their sustainability goals based on the insights gained in this research.

The first recommendation regards the ambition for electrolysis. The results of this research demonstrate that the potential of electrolysis goes beyond the government's current ambition of 3-4 GW 2030 and the most recent addition of 8 GW by 2032 [77]. In any case, this target should be enhanced to at least 9 GW. Until this capacity, a cost and CO_2 reduction is achieved in almost all scenarios, while keeping the chance of overinvestment to a minimum and allowing for achievable margins for market operators. Following this, the target can be expanded to 12 GW, the prudent capacity ensuring no regret in terms of costs or emission reduction. However, this is accompanied by an increased risk of over investment and a weaker financial proposition for investors. Consequently, this will require governmental intervention and, thus, higher societal costs by 2030. However, taking into account the rapid development of the energy transition, excessive investments are expected to be able to quickly retain a profitable market position after 2030. There is still a significant challenge ahead if the most prudent capacity of 38 GW for 2040 is to be reached. Early implementation of large-scale green electrolytic hydrogen production will foster the growth of the Dutch hydrogen economy, leading to accelerated demand for renewable hydrogen. Consequently, this will improve the potential for electrolysis. The Dutch government should thus aim to maximally stimulate the development of electrolytic hydrogen production until 2030, after which the prudent capacity can be determined based on the relation between and to the uncertainties.

The second recommendation lies within the relation of those uncertainties to the prudent electrolysis capacity. The prudent capacity of 38 GW for 2040 is heavily determined by its effect on the loss of load whilst knowing a high risk of excessive investment. As installed flexible capacity showed no correlation to investment in electrolysis capacity, the Dutch government should put additional effort into preventing this loss of load with the help of other flexibility technologies like batteries or demand side response. By utilising these other technologies, the goal is to ensure that additional electrolysis capacity no longer acts as a loss-of-load mitigation technology. As a result, the prudent capacity, solely based on costs and emission reduction, will be lower, thereby minimizing the risk of excessive capacity. In addition, when considering the uncertainties, hydrogen demand, peak residual load and hydrogen storage capacity are the key determinants of the potential for electrolysis capacity, of which the first is the most substantial. A fruitful environment for electrolysis can thus be created by adopting support schemes that stimulate the use of hydrogen or increase peak residual load. The results showed that the greatest potential lies in fuel switching from gas to hydrogen in industry and mobility, a mechanism susceptible to governmental intervention. The implementation of subsidies for the (re)construction of hydrogen-powered installations in industry or purchasing of hydrogen-powered fuel cell electric vehicles are examples of this.

Furthermore, a dilemma arises between cost reduction from a system perspective and the individual business case for electrolyser operators when adopting a prudent capacity. With the deployment of large capacities of electrolysis, it is inevitable that some of this capacity will only be operational for a limited number of hours per year. This research showed a mere 5.6% of full load hours and an average load of 26% for the final 4 GW in 2040. The hours in which these electrolysers reach full load, the significant overshoots of renewable electricity, are currently triggering negative electricity market prices. This phenomenon, in combination with the limited load hours, makes the incentive for investment in these final capacities extremely unfavourable, with margins over 11 EURO/kg being required to recoup the investments. Although, from a system perspective, it will result in an overall reduction of costs and emissions, assuming the least regret approach. In case the Dutch government wants to pursue these prudent capacities, we recommend installing financial incentives to trigger the last series of investments. First, a price floor must be implemented so that negative electricity prices are prevented. This can be done through a market-wide price floor or floor-price contract between the operator and the government. With this last structure, the government can compensate the operator with the difference if the market price drops below zero. Additionally, this policy could go one step further by creating a tender where operators can bid with their own tariffs. This starts as a more costly alternative, as the starting bids will be above zero, but it could increase competitiveness in the long run. In addition, investment subsidies similar to the IPCEI should be continued to reduce the CAPEX and stimulate the development [111].

It is essential to acknowledge that this recommendation is founded on the premise of achieving the prudent capacity. With this capacity, the goal is to ensure that the least regret in terms of costs, emissions and loss of load is achieved across all scenarios. However, it should be emphasized that the inability to reach this capacity does not result in excessive societal costs in the majority of the scenarios. In fact, for 75% (2030) and 97% (2040) of the scenarios, falling short of the prudent capacity by 1 GW does not increase societal costs. This percentage logically declines with the distance from the prudent capacity. Depending on the level of risk aversion, the policymaker can always choose to accept the possibility of forgoing potential cost and emission reductions by aiming for a lower capacity.

7.4 Further research

The study has yielded valuable insights that pave the way for future research. These findings provide a solid foundation to either expand the current work or explore new areas of research. In this section, we will discuss these findings and recommend avenues for further research.

The first and foremost recommendation is closely related to the most significant limitation of the modelling in this work; the absence of geographical conditions and transmission constraints. We currently assume a copper plate approach where all electricity is added to the same pile, while in reality, various bottlenecks limit the flow of electricity. One of the reasons for the growing support for hydrogen is its role in unburdening the already full electricity grid in the Netherlands. With the significant expansion in offshore wind, an inevitable consequence will be the increase in congestion at landfall. In this context, the role of hydrogen as a grid offloader could be enhanced even further. A new path of research exists in expanding this model with transportation aspects, for which three steps are identified;

1. The model could be expanded with an electricity grid to identify the biggest bottlenecks in congestion and, thus, the greatest potential for electrolysis as a grid offloader. General geographical demand and generation profiles must be included to achieve this. We recommend dividing this into a handful of regions like provinces so the highest level of abstraction, the congestion of the transmission grid, can be identified.

2. With the obtained knowledge regarding the limitations of electricity supply, the model should be expanded with geographical hydrogen demand profiles. The Dutch demand for hydrogen primarily stems from five large industry clusters; Rotterdam/Rijnmond, the North Sea Canal area, Chemelot, Zeeland and the North of the Netherlands. For the industry, it would be advantageous to have electrolysis capacity situated in proximity to these clusters. However, with the addition of the electricity grid, optimization can be performed to see where, from a system perspective, the most cost-effective locations are situated while adhering to transmission limits.

3. The inclusion of a hydrogen transportation network. Although currently in development, the Netherlands will dispose of a hydrogen network connecting all five industrial clusters. These three additions to the optimization model will result in a more substantiated answer for the most prudent electrolysis capacity. Furthermore, insights can be gained as to where the optimal electrolysis locations are in the Netherlands.

Instead of expansion of the Linny-R model, different models could also be used complementary to come to the same results or serve as validation.

The second recommendation for further research can be found in insights gained regarding the limited operational hours of electrolysis. This research showed that a large proportion of the future electrolysis capacity will only reach full load for a limited number of hours a year, making it an unattractive investment with current market structures. A research path exists in identifying what is required to make these investments worthwhile and what steps should be taken to reach this situation. This involves quantitative research into the business case for electrolysers to explore the conditions in which it can be profitable. Simultaneously, this research focuses on the design of the market structure and possible interventions by the government. Insights can be gained into what alternations need to be made for market investments to align with the optimal capacity from a system perspective.

Furthermore, further research could explore the role of electrolysis beyond the Dutch national borders. Over the coming years, the North Sea will become a large, interconnected electricity generation hub with connections between the Netherlands, Norway, the United Kingdom and Germany. During the course of this work, the Netherlands and the UK announced a new interconnector with a connection to one of the largest Dutch wind farms [91]. An extension of this work could model the wind parks, including the grid, in a detailed manner. In this way, the current model can serve as one 'cluster' for the Dutch hydrogen and electricity demand. Linny-R has a built-in function that allows the modeller to work with multiple owners of assets, so-called 'actors'. With this extension, investments regarding offshore electrolysis and interaction between the neighbouring countries can be explored. The results will create insights for policymakers to cooperate in the development of this meshed offshore grid and find the most cost-effective configurations.

Lastly, a research avenue exists in exploring the role of large-scale hydrogen storage in the future energy system of the Netherlands. In this research, the primary focus regarding hydrogen storage was examining its role in relation to electrolytic hydrogen production. However, no insights were gained into the minimal capacity required or the relation between UHS and other storage technologies. This could be done by expanding the storage cluster with new technologies and exploring the results of different configurations. Especially a comparison can be made between the role of lithium-ion batteries and hydrogen storage. Batteries are known to operate within short temporal cycles, but their relation to the role of underground hydrogen storage remains unexplored. Moreover, other forms of Power-to-X, such as Power-to-Heat or Power-to-Liquid[1] were disregarded in this research. Still, they could be explored in this avenue of research. Lastly, it is worth considering the role of storage in configurations where hydrogen production through SMR is phased out. In such cases, storage is expected to become significantly more crucial.

[1] Conversion of electricity into fuels like methane or jet fuel.

Chapter 8

Conclusion

The production of hydrogen through the electrolysis of renewable electricity has found increasing support over the years. Despite this support, it remains unknown what the proportions are in which this abundance of renewable electricity can and should be converted into hydrogen. The objective of this research is to determine what a prudent capacity for electrolytic hydrogen production is in the Netherlands until 2040, given the uncertainties in the future projections of supply and demand for both electricity and hydrogen. To this end, a model was developed that addressed this uncertainty through a series of systematically designed experiments and created insights into their relation to electrolysis capacity. In this chapter, the insights gained from these experiments will be used first to answer the sub-questions in order to ultimately form an adequate answer to the main research question.

SQ1 *What is, based on the availability of renewable electricity, the potential for production capacity of green electrolytic hydrogen in 2030?*

In 2030, more than 10 GW of renewable electricity will be available for approximately 1200 hours per year, equivalent to half of the current electricity supply. Consequently, it is crucial to introduce flexibility into the Dutch energy system to effectively manage the surplus of renewable electricity and prevent curtailment. This surplus also leads to a significant potential for electrolytic hydrogen production in 2030, ranging from 9 to 12 GW, surpassing the government's ambition of 3-4 GW. This allows for stimulation mechanisms that accommodate at least 9 GW in their agendas. By implementing these capacities, it becomes possible to consume 19 to 36% of VRES generation on an annual basis, contributing to the reduction of curtailment. Moreover, this target should not be limited, as additional capacity will be necessary for the subsequent years, as emphasized in the conclusion of the second sub-question.

SQ2 *How does the prudent production capacity of green electrolytic hydrogen depend on key uncertainties in 2040?*

In order to provide a conclusion on the key uncertainties and their relation to the prudent capacity, it is important to first define the values for electrolysis capacity in 2040. While in 2030 the range of electrolysis potential is relatively small, the potential of electrolysis in 2040 is enveloped in much greater uncertainty and ranges from 8 to 44 GW, with the most prudent capacity being 38 GW. The two key aggregated key uncertainties that most significantly determine this capacity are hydrogen demand and peak residual load, of which the first holds the highest degree of influence. In contrast, the flexible capacity of other technologies barely influences the potential for electrolysis capacity. As great quantities of renewable electricity will become available, this should thus be implemented alongside electrolysis, not being treated as competitors. Moreover, increasing offshore wind in combination with low electricity and hydrogen demand will actually result in lower investments in electrolysis. However, this phenomenon is reversed when the total energy demand increases. Having knowledge of these relations, it is thus important for policymakers to monitor the energy demand and other uncertainties in the Netherlands and adjust their ambitions accordingly.

SQ3 *To what extent does large-scale hydrogen storage capacity determine the potential for electrolytic hydrogen production capacity?*

The first and foremost conclusion is that large-scale hydrogen storage enables an increase in the potential for electrolysis, while, conversely, additional electrolysis does not contribute to the behaviour of storage facilities. For every 100 GWh of additional storage capacity, the potential of electrolysis increases by 500 MW. The injection and withdrawal rates are however very determinant in this relation and a doubling in these rates almost leads to a doubling in electrolysis potential. An additional important conclusion is that large capacities of underground hydrogen storage are not essential for the system to function. It enables cost and emission reduction but does not lead to disruption in meeting demand due to the availability of SMR. It can however be used as a policy instrument to facilitate the transition to a hydrogen economy.

Having formulated an answer to all three sub-questions, we can now conclude this research by answering the main research question:

What is the prudent production capacity of green electrolytic hydrogen in the Netherlands until 2040, while accounting for various uncertainties such as supply of renewable electricity and demand for carbon-free hydrogen?

Before we answer this main research question, one general statement must be made. Underlying all the conclusions drawn from this study is the notion that significant quantities of flexibility, in whatever form, become critical for the future Dutch energy system. During 1200+ hours a year, volumes of renewable electricity greater than the current hourly supply will become available as residual load, asking for technologies to deal with these fluctuations. Ultimately, these large quantities of renewable electricity lead to a prudent capacity of 12 GW in 2030 and 38 GW in 2040. In these 10 years, the potential for electrolysis is thus expected to increase exponentially and policymakers have a significant opportunity to play a proactive role in expediting the growth of the hydrogen economy by supporting the development of green hydrogen production. However, as these capacities are determined to have the least regret regarding cost reduction, emissions and loss of load, there is also an inherent risk of excessive investment associated with them; 75% of the scenarios in 2030 and 97% in 2040. Reducing the target capacity mitigates the risk of overinvestment, but concurrently heightens the risk of wasting cost and emissions reduction possibilities. For 2030, the no-regret capacity to be installed is 9 GW, as there is minimal chance of excessive investment and reductions are thus achieved risk-free. Regardless of the scenario, this capacity should be the minimum target that the Dutch government strives to achieve. For 2040, the uncertainties surrounding the potential for electrolysis capacity increase and the risk of overinvestment with it. As a result, no capacity was identified as a no-regret capacity regarding overinvestment. However, the prudent capacity is predominantly determined by its impact on loss of load. Diminishing this relationship by implementing other flexibility technologies as a loss of load mitigation measure will result in a lower capacity being considered the most prudent. This is desirable, as the minimum regret can be achieved with less risk of overinvestment. Consequently, this has the potential to reduce societal costs and gain increased support from both the societal and industry levels. Moreover, the last few gigawatts of the prudent capacities will primarily serve as peak production plants with minimal operational of less than 150 hours in 2040. As a result, the margins that are required to recoup this investment start at 11.00 EURO/kg. The existing market structure may not sufficiently incentivize investments. Therefore, while it is feasible to increase the target for installed capacity, achieving it would require a fundamental shift in the market structure or financial incentives from the government. If the latter can not stay within reasonable limits, pursuing the most prudent capacity may not be worthwhile, as it would impose an excessive burden on societal costs.

Based on the result and these conclusions, several policy recommendations have been given. First, the current ambition of 3-4 GW electrolysis capacity should be increased to at least 9 GW. In doing so, additional investments beyond this target should be encouraged as it will contribute to fostering the Dutch hydrogen economy and addressing the increased potential towards 2040. In addition, the development of electrolytic hydrogen production should be supported by adopting support schemes for increasing the use of hydrogen and peak residual load. Especially by fuel switching from gas and fossil-based fuels to hydrogen industry and mobility with, for example, subsidies for the (re)construction of hydrogen-powered installations in industry or purchasing of hydrogen-powered fuel cell electric vehicles. The last recommendation is to install financial incentives as a driving force for attaining the final gigawatts of electrolysis capacity. This consists of installing a market-wide electricity price floor, tenders for price tariffs and investment subsidies.

Furthermore, several research avenues were highlighted to build upon or extend the research in this work. The primary recommendation, addressing the most significant limitation, involves the expansion of a transport and transmission network. This should be done in three steps; 1) the inclusion of regional electricity demand and generation and a transmission grid, 2) the inclusion of regional hydrogen demand and generation and, 3) installing a hydrogen transportation network. As the second recommendation, it is advised to conduct research aimed at determining the prerequisites for making investments in the remaining gigawatts of electrolysis capacity economically viable, even with limited load hours. This involves quantitative research into the business case, but also on market design and possible governmental interventions. Furthermore, a research avenue exists in exploring the role of electrolysis in the future electricity generation hub of the North Sea. An extension can be made to the current Linny-R model, exploring interactions between neighbouring countries regarding investments in electrolysis. Lastly, research could be devoted to the role of large-scale hydrogen storage in the future energy system of the Netherlands, gaining insights into the minimum capacity required and the relation to other storage technologies.

All in all, this research has produced insights into the potential for electrolysis capacity, the capacity that can be considered prudent from a system perspective and its relation to the uncertainties in projections of supply and demand for both hydrogen and electricity. With these insights, it gives the policymaker handles for determining an electrolysis capacity while dealing with the uncertainties that are involved with shaping the future Dutch energy system.

Chapter 9

Reflection

This chapter reflects the process involved in writing this master thesis. It begins by examining the decision to utilize Linny-R as the chosen modelling tool. Following this, a critical analysis of the overall thesis writing process will be presented, highlighting areas that could have been improved or acknowledging successful aspects. Finally, a personal perspective will be shared to add a subjective element to the reflection.

Reflection on Linny-R - In Chapter 2, a comprehensive analysis was conducted to come to the right modelling tool for this work. Linny-R was selected over other comparable modelling tools due to its clear and transparent communication and ability to switch the optimization time step with just one click. The transparency of Linny-R has been used on multiple occasions in communication with other experts from Energie Beheer Nederland, TNO and TU Delft. Prior to the final defence of my thesis, I participated in four different presentation sessions specifically focused on my model, during which I was able to delve into the core of my model in a short period of time. This helped in the validation of the model, as the experts in the session were directly able to identify the modelled relations and ask questions or provide feedback. An example of this is the electricity consumption of the injection process of underground hydrogen storage. After one of the presentation sessions at Energie Beheer Nederland, one of the experts noticed the limited links flowing in and out of this process and started a discussion regarding the efficiency of hydrogen injection. As a result of this discussion, the electricity consumption for the charging process was included. In addition, the easy switching between time steps turned out extremely helpful for quick validation of the model. After each addition, the behaviour of the model could be tested quickly through an increase of the time step to, for example, days, thereby heavily reducing the computational time. Moreover, it allowed me to switch to a 4-hour time step after the model had already been constructed. As also described in Chapter 2, Linny-R is still under development, something I also encountered. This was however in all cases quickly resolved due to the quick bug fixes from the developer of Linny-R. An example of this is the built-in sensitivity analysis function. While immensely helpful for my research, I did encounter some bugs as I was the first user to extensively test this functionality on such a large scale. After contacting the developer, the issue was resolved within a few days.

Reflection on the process - After completing this work, it allows for a reflection on the process itself and an identification of the things I would have done differently or, on the contrary, the strengths. The systematic method used for constructing the experiment design, both on impact and uncertainty, is something I find to be a strength of my work. However, the actual execution of this experiment design could have been improved by not blindly executing my own rules. Each series of experiments is different and could have been treated in its own manner. An example is the range of values picked for the '2040 - capacity comparison' series. Analysing a range of lower capacities and comparing those to the current range analysed would have given interesting insights, something I, unfortunately, ran out of time for. Furthermore, a known pitfall for constructing a model as a part of a master thesis is planning, or better, deciding to finalize the model in time. This is something I was frequently warned about, but fortunately, I was able to steer clear of it. As a result, I managed to conduct a significant number of experiments without letting an error that surfaced towards the later stages cause any severe trouble to my process.

Personal reflection - From a personal point of view, there are some points I learned from or struggled with. On multiple occasions, I encountered errors in my work while already quite far in the process due to not thoroughly checking the work I was building upon before going to the next step. An example of this is discovering an error in the model after the completion of roughly 80% of my experiments. This taught me to be more thorough in executing new methods and checking my progress along the way. Secondly, something I underestimated was the complexity of robustness and particularly the effective communication for robust decision-making. Although generating insightful results, being able to extract the correct conclusions turned out to be rather difficult. After receiving feedback and discussing this on multiple occasions, I believe I learned greatly from it and was able to provide both insightful results and produce valuable recommendations. Lastly, constructing a model of the Dutch hydrogen and electricity systems required me to delve more deeply into the transition of the Dutch energy system. Because of this, I gained a deeper understanding of the far-reaching complexity of the energy transition. For this work, I focused on one specific aspect; hydrogen production through the electrolysis of renewable electricity. This is, however, just one of the many components that need to go through a transition for us to be able to reduce our carbon emissions drastically. At the same time, a significant proportion of these components are either interchangeable or require development in other places to reach their potential. Constructing the model and discussing it with many experts showed me the magnitude of possibilities and decisions to be made in the coming years.

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Appendix A

Technical parameters and input variables

In this appendix, all the values that have been put into the model are explained. There are certain inputs that remain constant and do not vary across different base scenarios or experiments, known as technical parameters. These technical parameters encompass various factors such as efficiencies and energy consumption. All technical parameters are given in Table A.1.

Table A.1: Technical parameters.

Parameters	Value	Unit	Reference
Gas CCGT efficiency	60	%	[47, 22]
Gas OCGT efficiency	40	%	[52, 60]
Biomass efficiency	40	%	[49, 50, 134]
CHP efficiency	36	%	[25]
CCS capture rate	70	%	[2]
Underground hydrogen storage capacity	200	GWh	[46]
Underground hydrogen storage efficiency	98	%	[46]
Underground hydrogen storage injection rate	1	GWh/h	[129]
Underground hydrogen storage withdrawal rate	1.2	GWh/h	[129]
Electricity consumption hydrogen compression	0.15	GWh_e/GWh_{H_2}	[37, 6, 95]
Value of lost load	3	MEUR/GWh	[86]
Lithium-ion roundtrip efficiency	85	%	[15]
Lithium-ion self-discharge rate	1	%/day	[15]
Lithium-ion charge and discharge rates	∞	-	-
Hydrogen consumption refineries	0.416625	$GWh_{H_2}/kton_{crude\ oil}$	[103]
Oil-based fuels production rate refineries	0.746	$Kton_{fuel}/kton_{crude\ oil}$	[23]
Hydrogen CCGT efficiency	51.9	%	[113]
Hydrogen OCGT efficiency	33.4	%	[113]
SMR efficiency	0.74	%	[13]
Electricity consumption SMR with CCS	0.027	GWh_e/GWh_{H_2}	[126]
Electrolysis efficiency	75	%	[121, 118]
Biomass gasification efficiency	68	%	[29, 5]

A.1 Electrolyser investment costs

Investments in the Linny-R model are based on the annuity of standard-sized 200 MW stacks. Table A.2 gives an overview of the electrolyser CAPEX and expected lifetime for 2030 and 2040 obtained from the literature. Based on the average of this table, we assume a CAPEX of 400 EURO per kW and a lifetime of 20 years. Following these assumptions, the annuity for a 200MW stack is 4 MEURO [1]. Based on the small variations between the prediction years and uncertainty regarding the validity, we assume the same CAPEX for 2030 and 2040.

1 $\frac{400(\text{EURO/kW}) \times 1000(\text{kW/MW}) \times 200(\text{MW/stack})}{20(\text{y/stack}) \times 1000000(\text{EURO/MEURO})} = 4\,\text{MEURO}$

Table A.2: Electrolyser investment costs predictions

Prediction year	Price per kw [EURO]	Lifetime [y]	Reference
2040	520	30	[54]
2030	550	20	[117]
2040	300-400	20	[34]
2030	320-400	-	[104]

A.2 Input values base scenario 2030

The input values for the base scenario of 2030, have been largely based on the 'Klimaatambitie (KA)' (Climate ambition) scenario of IP2024 by Netbeheer Nederland [86]. This allows for quick and transparent validation, as certain outputs of the base scenarios can be validated with the IP2024 results. Moreover, KA is one of three scenarios of IP2024, next to 'Nationale drijfveren (ND)' (National drivers) and 'Internationale ambitie (IA)' (International ambition). For 2030, the objective is to gain insights into the potential for green electrolytic hydrogen production, based on current Dutch and European policies. The scenario KA is based on all existing and planned energy and climate policies together with the ambitions already published in the Coalition agreement of the Dutch government. By taking this as the base scenario, we stay in line with the objective of this research. All the input values, together with their reference, are published in Table A.3. It should be noted that some variables still have a value of 0, as they are expected to be developed after 2030. Moreover, the import price of electricity, for both 2030 and 2040, has a self-defined value that is greater than the most costly electricity generation asset. The import price of electricity, like the domestic electricity price, is dynamic and established on the day-ahead market. Including this in the model is too complicated for this work and is therefore left out of the scope. Instead, we assume the import of electricity to be a flexible option in times of shortage. By making import the most costly source of electricity, it will only be toggled in times of real shortage, where all domestic generation units are already switched on.

A.3 Input values base scenario 2040

Similar to the base scenario of 2030, the base scenario of 2040 is also largely based on one specific scenario. To keep the base scenarios comparable, a scenario has been chosen that has been constructed also been constructed by Netbeheer Nederland. It concerns the 'Nationaal Leiderschap (NAT)' (National Leadership) scenario of the II3050 scenario study [85]. In this scenario, the Dutch government aims for an energy-efficient system which is mostly powered by domestic capabilities and production. In the other scenarios, 'Decentrale Initiatieven (DEC)' (Decentral Initiatives), 'Europese Integratie (EUR)' (European Integration) and 'Internationale Handel (INT)' (Internation Trade), the Dutch is either predominantly focussed on import and export or on decentral production. The first does not fit well with our assumption to consider import as a flexibility option rather than a base-load production method. The latter is not compatible with the level of abstraction implemented in the model. Decentral production is highly associated with geographical constraints, which are not considered in this work. All the input values including the references can be found in Table A.4.

Table A.3: Input values base scenario 2030.

Variable	Value	Unit	Reference
Installed capacity nuclear	0.485	GW	[90]
Installed capacity OCGT	0.09	GW	[86]
Installed capacity CCGT	9.243	GW	[86]
Installed capacity CCGT with CCS	0	GW	[86]
Installed capacity biomass	0.4	GW	[86]
Installed capacity waste	0.283	GW	[86]
Installed capacity wind onshore	9.1	GW	[86]
Installed capacity wind offshore	21.5	GW	[86, 74]
Installed capacity wind offshore for P2X	0.6	GW	[86]
Installed capacity solar PV	59.3	GW	[86]
Biomass price	0.057	MEURO/GWh	[86]
Nuclear electricity price	0.03399	MEURO/GWh	[63]
Gas price	0.035	MEURO/GWh	[96]
Import price electricity	0.15	MEURO/GWh	Own assumption
Import price hydrogen	0.1375	MEURO/GWh	[3]
Interconnection capacity	12.8	GW	[86]
Import capacity hydrogen	2.55	GW	[86]
By-product hydrogen production	15197	GWh/y	[86]
Installed capacity SMR with CCS	5.227	GW	[86]
Installed capacity SMR	0	GW	[86]
Installed capacity biomass gasification	0.4	GW	[86]
Industrial heat demand industry	156700	GWh/y	[86]
Electricity ratio of industrial heat demand	35	%	[86]
Hydrogen ratio of industrial heat demand	26	%	[86]
Industry flex capacity	1.7	GW	[86]
Heating demand built environment	138100	GWh/y	[86]
Electricity ratio of heating demand built environment	38	%	[86]
Heat network ratio of heating demand built environment	9	%	[86]
Energy demand mobility	123800	GWh/y	[86]
Electricity ratio of energy demand mobility	15	%	[86]
Hydrogen ratio of energy demand mobility	3	%	[86]
Other ratio of energy demand mobility	11	%	[86]
External demand for oil-based fuels	44.3	%	[9]
Hydrogen demand as a feedstock	19298	GWh/y	[86]
Electricity demand agriculture	9900	GWh/y	[86]
Electricity demand ICT	9800	GWh/y	[86]
Hydrogen CCGT capacity	0	GW	[86]
Hydrogen OCGT capacity	0	GW	[86]
Number of storages	4		[45, 46]
Lithium-ion storage capacity	12.3	GW	[86]
Carbon price	0.13679	MEURO/GWh	[19]

Table A.4: Input values base scenario 2040.

Variable	**Value**	**Unit**	**Referenc**
Installed capacity nuclear	1.455	GW	[90]
Installed capacity OCGT	0.032	GW	[85]
Installed capacity CCGT	4.92	GW	[85]
Installed capacity CCGT with CCS	0	GW	[85]
Installed capacity biomass	0.15	GW	[85]
Installed capacity waste	0	GW	[85]
Installed capacity wind onshore	15.1	GW	[85]
Installed capacity wind offshore	41.5	GW	[85]
Installed capacity wind offshore for P2X	9	GW	[85]
Installed capacity solar PV	122.7	GW	[85]
Biomass price	0.058	MEURO/GWh	[85]
Nuclear electricity price	0.02759	MEURO/GWh	[85]
Gas price	0.015	MEURO/GWh	[85]
Import price electricity	0.15	MEURO/GWh	Own assumption
Import price hydrogen	0.03	MEURO/GWh	[85]
Interconnection capacity	14.8	GW	[85]
Hydrogen import capacity	1.682	GW	[85]
By-product hydrogen production	15917	GWh/y	[85]
Installed capacity SMR with CCS	2.583	GW	[85]
Installed capacity SMR	0	GW	[85]
Installed capacity biomass gasification	0.37	GW	[85]
Industrial heat demand industry	165400	GWh/y	[85]
Electricity ratio of industrial heat demand	53	%	[85]
Hydrogen ratio of industrial heat demand	31	%	[85]
Industry flex capacity	5.1	GW	[85]
Heating demand built environment	108100	GWh/y	[85]
Electricity ratio of heating demand built environment	55	%	[85]
Heat network ratio of heating demand built environment	23	%	[85]
Energy demand mobility~	88357	GWh/y	[85]
Electricity ratio of energy demand mobility	56	%	[85]
Hydrogen ratio of energy demand mobility	9	%	[85]
Other ratio of energy demand mobility	25	%	[85]
External demand for oil-based fuels	80	%	[9]
Hydrogen demand as a feedstock	19301	GWh/y	[85]
Electricity demand agriculture	13600	GWh/y	[85]
Electricity demand ICT	16400	GWh/y	[85]
Number of storages	32		[132]
Hydrogen OCGT capacity	2.97	GW	[85]
Hydrogen CCGT capacity	5.94	GW	[85]
Lithium-ion storage capacity	42	GW	[85]
Carbon price	0.1358	MEURO/GWh	[20]

Appendix B

Outputs base scenarios

This appendix provides supplementary outputs or inputs that are referenced in the main text but are not included for relevance. These additional figures offer further data or supporting information to enhance the understanding and context of the main text.

Figure B.1 gives the demand pattern for the built environment, as implemented in all experiment runs. It shows a clear seasonal pattern with it absolute peak around time step 800.

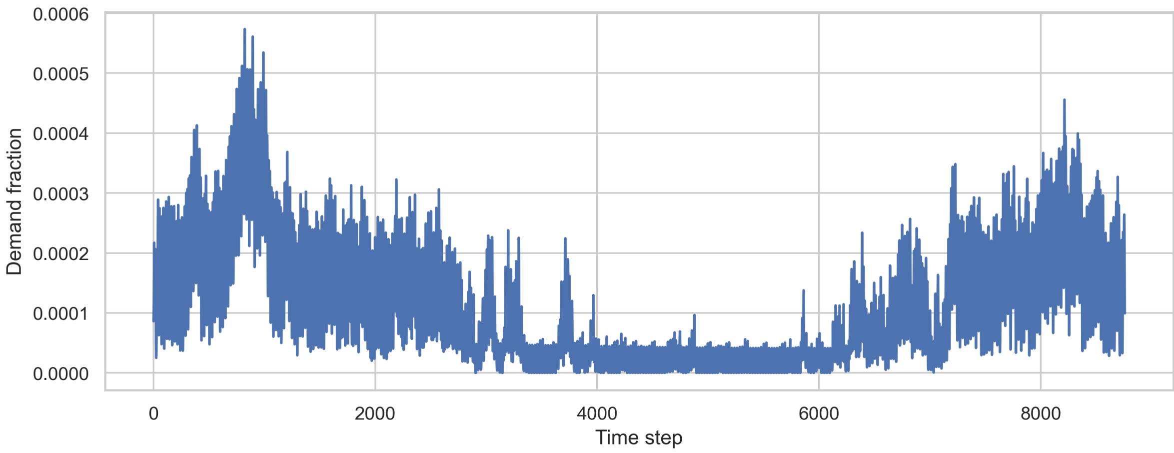

Figure B.1: Built environment demand pattern.

Figures B.2 and B.3 give the weekly average wind production factors for 1999 and 2019, respectively. The dunkelflaute of the 1999 weather year is clearly visible in the first two months of the year, between approximately time step 400 and 800.

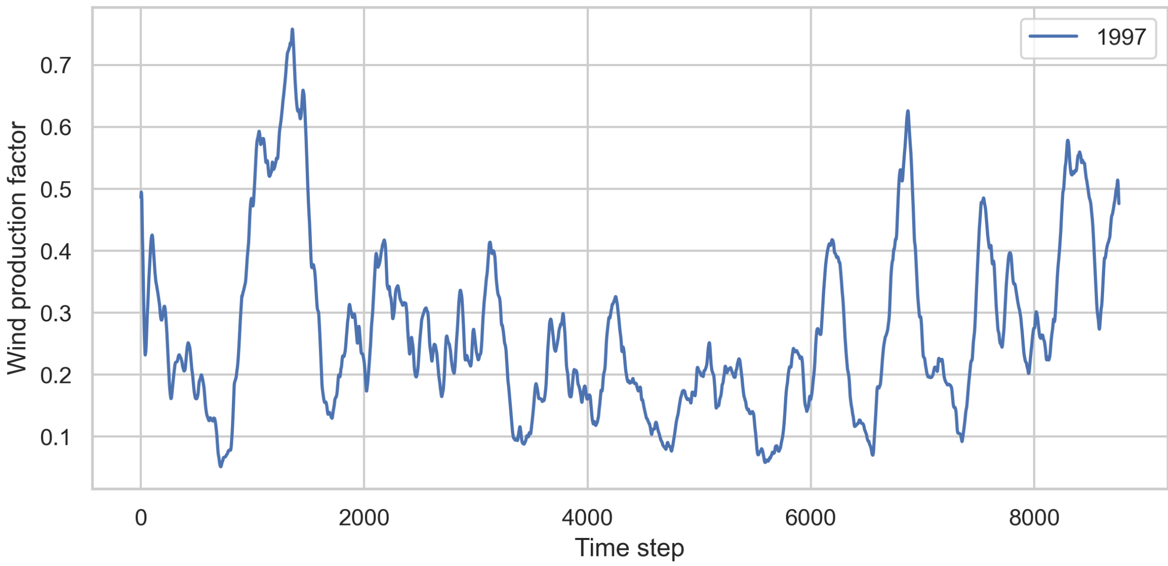

Figure B.2: Weekly average wind production factor 1999.

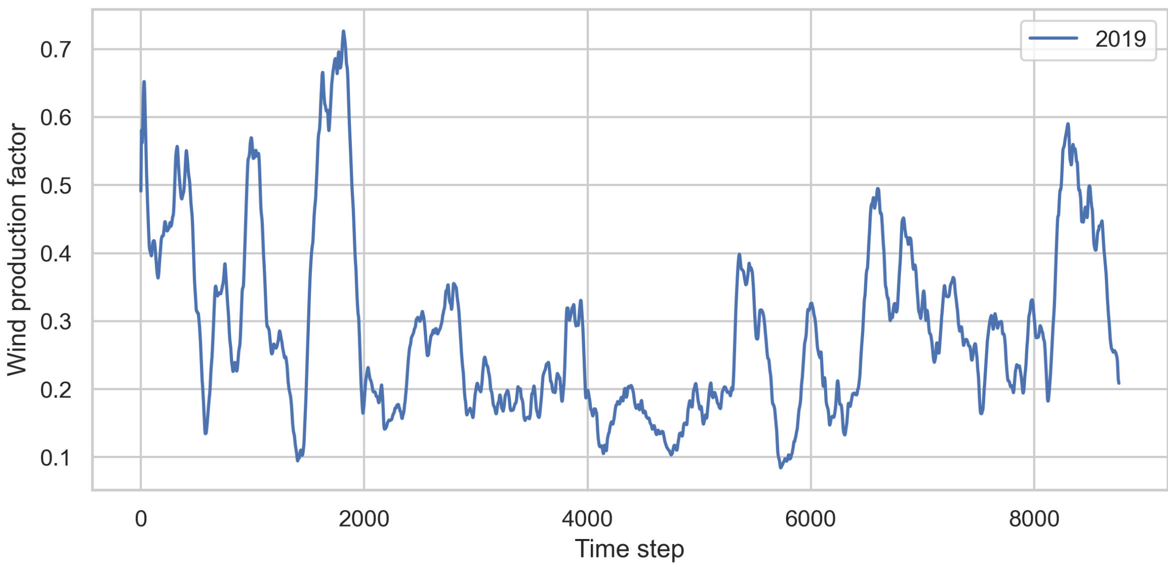

Figure B.3: Weekly average wind production factor 2019.

Appendix C

Storage constraints

In this appendix, we explain the reasoning behind the constraints added to the underground hydrogen storage for the last time step. In order to accurately determine this minimum filling rate, 10 consecutive weather years were optimized, from 2010 up until 2019. As the goal is to imitate the settings used in the runs conducted for the experiments, the solver should have knowledge of 1 whole year for each optimization block. For this reason, the block length is set at 548 (1 quarter) and the look-ahead at 1642 (3 quarters). In this way, the solver optimizes blocks of one quarter instead of the whole year but still possesses knowledge for the remainder of the year. If 1-year block lengths were used, the solver would have still emptied the storage at the final time step of that block. Figures C.1 and C.2 show the storage behaviour for 2030 and 2040. Tables C.1 and C.2 give the filling rate of the storage for the final time step of each year. Based on this analysis, a constraint is added to the underground hydrogen storage product demanding a filling rate on the final time step of 41% for 2030 and 47% for 2040.

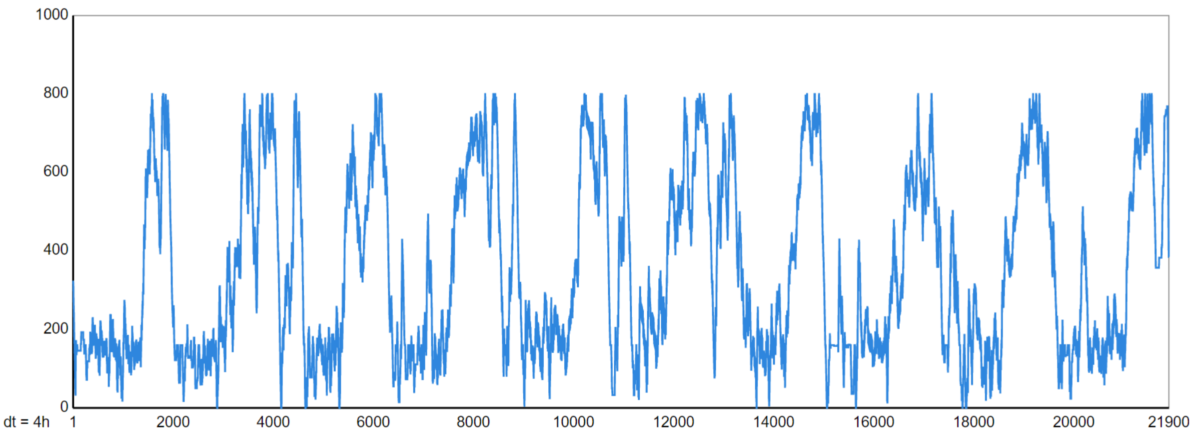

Figure C.1: Underground hydrogen storage 2030 - weather years 2010-2019.

Table C.1: Underground hydrogen storage 2030 - weather years 2010-2019 - end of year filling rates.

Year	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**Average**
Value	116	369	322	333	391	757	310	258	66	325
Percentage	15%	46%	40%	42%	49%	95%	39%	32%	8%	41%

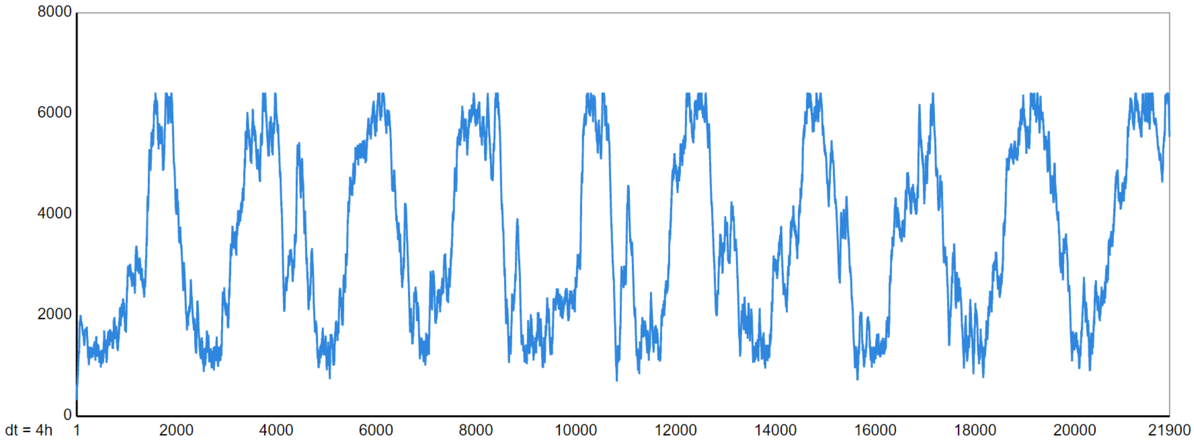

Figure C.2: Underground hydrogen storage 2040 - weather years 2010-2019.

Table C.2: Underground hydrogen storage 2040 - weather years 2010-2019 - end of year filling rates.

Year	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**Average**
Value	2067	3420	3755	2263	2656	4047	3691	2249	3074	3025
Percentage	32%	53%	59%	35%	42%	63%	58%	35%	48%	47%

Appendix D

Impact and uncertainty analysis

In this appendix, the establishment of the relative impact and uncertainty of each input variable is discussed.

The relative impact score of each variable on each KPI, as explained in Chapter 5, are displayed in Figure D.1 for 2030 and Figure D.2 for 2040. The relative impact of wind and solar is not included in the table, because it was not and could not be included in the sensitivity analysis. However, because of the well-known impact of a dunkelflaute on the security of supply, we consider the impact of wind and solar to be 5.

As described in Chapter 5, the relative uncertainty of each input variable is based on the extent of concurrence of the data retrieved from the literature. Some input variables do not fit in the normalization method used to determine the relative uncertainty. The values for these variables were based on four different forms of logic, with a different score for each logic. They are denoted with raised text in the tables, with the following reasoning:

1. This notation concerns the weather data. Weather data is extremely uncertain due to the complex and chaotic nature of atmospheric processes and the large number of factors involved. With current technologies it is still not possible to, for example, precisely predict wind speed months ahead. Due to this rationale, the uncertainty of weather data is assumed to be 5.

2. The relative uncertainties denoted with a '2' concern the variables for which only one source of data could be found. To account for the limitation of a single data point having no range, an alternative notation is necessary. Relying solely on one source for data does not enhance the credibility of this work. Moreover, when there is only one value, it often indicates difficulty in prediction or failed predictions. For these reasons, we can conclude that having only one data can be considered as uncertain and is therefore indicated with a value of 4.

3. The relative uncertainties denoted with this number regard the values that know no uncertainty. This could be a result of technical aspects, like the technical impossibility to construct additional storage before 2030 in addition to HyStock's 4 salt cavern storage units or locked-in policy [45]. The reason the offshore wind capacity targets are not seen as a locked-in policy is the fact that it still depends on the technical feasibility. As there is uncertainty, these variables have a value of 1.

4. This number solely belongs to the import price of electricity. The value is defined by the modeller, as explained in Appendix A. As this involves no uncertainty, the value is also 1.

The results for the relative uncertainty of each input variable are given in Table D.3 for 2030 and Table D.4 for 2040.

Table D.1: Relative impact assessment 2030.

Variable	Total costs	CO2 emissions	Electrolysis (max)	Loss of load	Max
			Relative impact		
Installed capacity nuclear	1	1	1	1	1
Installed capacity OCGT	1	1	1	1	1
Installed capacity CCGT	1	1	1	5	5
Installed capacity biomass	1	1	1	1	1
Installed capacity waste	1	1	1	1	1
Installed capacity wind onshore	1	1	1	2	2
Installed capacity wind offshore	2	1	1	3	3
Installed capacity wind offshore for P2X	1	1	1	1	1
Installed capacity solar PV	1	1	1	1	1
Biomass price	1	1	1	1	1
Uranium price	1	1	1	1	1
Gas price	2	1	1	1	2
Import price electricity	1	1	1	1	1
Import price hydrogen	1	1	1	2	2
Interconnection capacity	1	1	1	5	5
Import capacity hydrogen	1	1	1	1	1
By-product hydrogen production	2	1	2	1	2
Installed capacity SMR with CCS	1	1	1	1	1
Installed capacity biomass gasification	1	1	1	1	1
Industrial heat demand	5	5	5	5	5
Electricity ratio of industrial heat demand	2	1	1	5	5
Hydrogen ratio of industrial heat demand	2	1	2	1	2
Flexible industry capacity	1	1	2	4	4
Heating demand BE	3	2	1	5	5
Electricity ratio of heating demand BE	3	2	1	5	5
Heat network ratio of heating demand BE	1	1	1	1	1
Energy demand mobility	2	1	1	5	5
Electricity ratio of energy demand mobility	2	1	1	5	5
Hydrogen ratio of energy demand mobility	1	1	1	1	1
Other ratio of energy demand mobility	1	1	1	1	1
External demand for oil-based fuels	1	1	1	1	1
Hydrogen demand as a feedstock	1	1	1	1	1
Electricity demand agriculture	1	1	1	3	3
Electricity demand ICT	1	1	1	3	3
Numer of underground hydrogen storages	1	1	1	1	1
Lithium-ion storage capacity	1	1	1	5	5
Carbon price	2	1	1	1	2

Table D.2: Relative impact assessment 2040.

Variable	**Total costs**	**CO2 emissions**	**Electrolysis (max)**	**Loss of load**	**Max**
			Relative impact		
Installed capacity nuclear	1	1	1	2	2
Installed capacity OCGT	1	1	1	1	1
Installed capacity CCGT	1	1	1	4	4
Installed capacity biomass	1	1	1	1	1
Installed capacity waste	1	1	1	1	1
Installed capacity wind onshore	3	1	1	2	3
Installed capacity wind offshore	1	1	1	1	1
Installed capacity wind offshore for P2X	1	1	1	1	1
Installed capacity solar PV	1	1	1	1	1
Biomass price	1	1	1	1	1
Uranium price	1	1	1	1	1
Gas price	1	1	1	1	1
Import price electricity	1	1	1	1	1
Import price hydrogen	1	1	1	5	5
Interconnection capacity	1	1	1	1	1
Import capacity hydrogen	1	1	1	1	1
By-product hydrogen production	1	1	1	1	1
Installed capacity SMR with CCS	1	1	1	1	1
Installed capacity biomass gasification	5	5	1	5	5
Industrial heat demand	5	1	1	5	5
Electricity ratio of industrial heat demand	3	1	1	1	3
Hydrogen ratio of industrial heat demand	3	1	2	5	5
Flexible industry capacity	5	2	1	5	5
Heating demand BE	5	4	1	5	5
Electricity ratio of heating demand BE	1	2	1	1	2
Heat network ratio of heating demand BE	5	2	1	5	5
Energy demand mobility	5	2	1	5	5
Electricity ratio of energy demand mobility	1	1	1	1	1
Hydrogen ratio of energy demand mobility	1	1	1	1	1
Other ratio of energy demand mobility	1	1	1	1	1
External demand for oil-based fuels	1	1	1	1	1
Hydrogen demand as a feedstock	1	1	1	1	1
Electricity demand agriculture	1	1	1	2	2
Electricity demand ICT	1	1	1	1	1
Numer of underground hydrogen storages	1	1	1	2	2
Lithium-ion storage capacity	1	1	1	1	1
Carbon price	2	1	1	4	4

Table D.3: Relative uncertainty 2030.

Variable	Range 2030	Unit	Relative uncertainty	Uncertainty
Wind speed	-	-	0.00	5[1]
Solar irradiance	-	-	0.00	5[1]
Installed capacity nuclear	0.485	GW	0.00	1[3]
Installed capacity OCGT	0.09-4	GW	1.91	5
Installed capacity CCGT	6-14.7	GW	0.84	3
Installed capacity CCGT with CCS	2	GW	0.00	1
Installed capacity biomass	0.4-4	GW	1.64	4
Installed capacity waste	0.224-0.283	GW	0.00	1
Installed capacity wind onshore	8-10.3	GW	0.25	2
Installed capacity wind offshore	12-21.5	GW	0.57	2
Installed capacity wind offshore for P2X	0.6-2	GW	1.08	3
Installed capacity solar PV	26-76.1	GW	0.98	3
Biomass price	0.057	MEURO/GWh	0.00	4[2]
Nuclear electricity price	0.0399-0.043	MEURO/GWh	0.08	1
Gas price	0.035-0.04209	MEURO/GWh	0.18	1
Import price electricity	0.15	MEURO/GWh	0.00	1[4]
Import price hydrogen	0.057-0.1375	MEURO/GWh	0.83	3
Interconnection capacity	12.8-25	GW	0.65	2
Import capacity hydrogen	0.2-5.7	GW	1.86	5
By-product hydrogen production	15917	GWh	0.00	4[2]
Installed capacity SMR with CCS	5.227	GW	0.00	4[2]
Installed capacity biomass gasification	0-0.4	GW	2.00	5
Industrial heat demand	104167-158400	GWh	0.41	2
Electricity ratio of industrial heat demand	0.33-0.40	%	0.19	1
Hydrogen ratio of industrial heat demand	0.25-0.29	%	0.15	1
Flexible industry capacity	1.5-2	GW	0.29	2
Heating demand BE	109722-146667	GWh	0.29	2
Electricity ratio of heating demand BE	0.36-0.45	%	0.22	1
Heat network ratio of heating demand BE	0.08-0.1188	%	0.39	2
Energy demand mobility	113700-171667	GWh	0.41	2
Electricity ratio of energy demand mobility	0.06-0.23	%	1.17	3
Hydrogen ratio of energy demand mobility	0.0003-0.06	%	1.98	5
Other ratio of energy demand mobility	0.08-0.15	%	0.61	2
External demand for oil-based fuels	80	%	0.00	4[2]
Hydrogen demand as a feedstock	19298	GWh	0.00	4[2]
Electricity demand agriculture	8333-13000	GWh	0.44	2
Electricity demand ICT	7600-13200	GW	0.54	2
Installed capacity hydrogen OCGT	0	GW	0.00	1
Installed capacity hydrogen CCGT	0	GW	0.00	1
Number of underground hydrogen storages	4	#	0.00	1[3]
Lithium-ion storage capacity	8.3-19.3	GW	0.80	3
Carbon price	0.13679-0.09	MEURO/GWh	0.41	2

Table D.4: Relative uncertainty 2040.

Variable	Range 2040	Unit	Relative uncertainty	Uncertainty
Wind speed	-	-	0.00	5[1]
Solar irradiance	-	-	0.00	5[1]
Installed capacity nuclear	1.455	GW	0.00	1[3]
Installed capacity OCGT	0-0.5	GW	2.00	5
Installed capacity CCGT	2.086-8.5	GW	1.99	5
Installed capacity CCGT with CCS	0-0.5	GW	2.00	5
Installed capacity biomass	0.15-3.5	GW	1.84	5
Installed capacity waste	0	GW	0.00	1
Installed capacity wind onshore	8-15.1	GW	0.61	2
Installed capacity wind offshore	31.5-45	GW	0.35	2
Installed capacity wind offshore for P2X	0-9	GW	2.00	5
Installed capacity solar PV	60-126.1	GW	0.71	2
Biomass price	0.030-0.045	MEURO/GWh	0.40	2
Nuclear electricity price	0.02758	MEURO/GWh	0.00	4[2]
Gas price	0.015	MEURO/GWh	0.00	1
Import price electricity	0.15	MEURO/GWh	0.00	1[4]
Import price hydrogen	0.03	GW	0.00	4[2]
Interconnection capacity	14.8-25	GW	0.51	2
Import capacity hydrogen	1.682-19.379	GW	1.68	4
By-product hydrogen production	15917	GWh	0.00	4[2]
Installed capacity SMR with CCS	2.583-4.35	GW	0.51	2
Installed capacity biomass gasification	0.37-0.9	GW	0.83	3
Industrial heat demand	104167-184600	GWh	0.56	2
Electricity ratio of industrial heat demand	0.33-0.53	%	0.47	2
Hydrogen ratio of industrial heat demand	0.30-0.43	%	0.36	2
Flexible industry capacity	2.5-5.1	GW	0.68	2
Heating demand BE	105556-118000	GWh	0.11	1
Electricity ratio of heating demand BE	0.53-0.58	%	0.09	1
Heat network ratio of heating demand BE	0.11-0.23	GWh	0.71	2
Energy demand mobility	88357-228611	GWh	0.88	3
Electricity ratio of energy demand mobility	0.05-0.23	%	0.74	2
Hydrogen ratio of energy demand mobility	0.0003-0.06	%	1.98	5
Other ratio of energy demand mobility	0.17-0.36	%	0.72	2
External demand for oil-based fuels	0.8	%	0.00	4[2]
Hydrogen demand as a feedstock	19301	GWh	0.00	4[2]
Electricity demand agriculture	8333-13600	GWh	0.48	2
Electricity demand ICT	13200-16400	GW	0.22	1
Installed capacity hydrogen OCGT	5.94-13	GW	0.75	2
Installed capacity hydrogen CCGT	2.97-9	GW	1.01	3
Number of underground hydrogen storages	4.0-32	#	1.56	4
Lithium-ion storage capacity	10-42.2	GW	1.23	3
Carbon price	0.123-0.13579	MEURO/GWh	0.10	1

Appendix E

Heat map of electrolysis capacity of the investment decision experiment

In this appendix, the heat map of the electrolysis capacity of the investment decision experiment is given. The weather year behind this table is the normal weather year of 2019.

					MB-l																MB-h															
					IH-l								IH-h								IH-l								IH-h							
					FL-h				FL-l				FL-h				FL-l				FL-h				FL-l				FL-h				FL-l			
					EIH-l		EIH-h		EIH-l		EIH-h		EIH-l		EIH-h		EIH-l		EIH-h		EIH-l		EIH-h		EIH-l		EIH-h		EIH-l		EIH-h		EIH-l		EIH-h	
					INT-l	INT-h	INT-l	INT-h	INT-l	INT-h	INT-l	INT-h	INT-l	INT-h	INT-l	INT-h	INT-l	INT-h	INT-l	INT-h	INT-l	INT-h	INT-l	INT-h	INT-l	INT-h	INT-l	INT-h	INT-l	INT-h	INT-l	INT-h	INT-l	INT-h	INT-l	INT-h
OFF-h	EMB-l	LI-h	GAS-h	H2T-l	7.4	7.6	9.8	9.8	11.0	11.0	13.4	13.4	13.8	13.8	17.0	17.0	17.2	17.2	20.6	20.6	15.0	15.0	15.0	15.0	17.2	17.2	19.6	19.6	20.8	20.8	25.4	25.4	23.2	23.2	31.8	31.8
				H2T-h	7.8	8.0	10.4	10.2	11.4	11.4	14.0	14.0	14.0	14.0	17.0	17.0	17.2	17.2	20.8	20.8	15.2	15.2	15.0	15.0	17.2	17.2	19.8	19.8	20.8	20.8	25.4	25.4	23.2	23.2	31.8	31.8
			GAS-l	H2T-l	8.0	7.9	10.0	10.0	11.2	11.2	14.0	14.0	14.4	14.4	17.4	17.4	17.4	17.4	21.2	21.2	15.2	15.4	15.8	15.8	17.4	17.4	20.0	20.0	21.0	21.0	25.4	25.4	25.4	25.4	32.0	32.0
				H2T-h	8.0	7.9	10.4	10.4	11.4	11.4	14.6	14.6	14.6	14.6	18.4	18.4	17.4	17.4	22.6	22.6	15.6	15.6	15.8	15.6	17.4	17.4	19.8	19.8	22.2	22.2	25.4	25.4	25.4	25.4	32.0	32.0
		LI-l	GAS-h	H2T-l	8.8	8.8	11.1	11.1	12.4	12.4	14.8	14.8	15.8	15.8	19.6	19.6	20.0	20.0	22.6	22.6	16.6	16.6	17.6	17.6	19.2	19.2	21.4	21.4	23.0	23.0	30.2	30.2	26.8	26.8	37.4	37.4
				H2T-h	9.0	9.0	11.4	11.3	13.0	13.0	15.4	15.4	15.8	15.8	19.8	19.8	20.4	20.4	22.8	22.8	17.0	16.8	17.6	17.6	19.0	19.0	21.2	21.2	23.4	23.4	30.4	30.4	26.8	26.8	37.2	37.2
			GAS-l	H2T-l	8.8	8.8	11.3	11.3	13.0	13.0	15.4	15.4	16.2	16.2	20.4	20.4	20.4	20.4	22.8	22.8	17.0	16.8	17.8	17.8	19.4	19.4	21.8	21.8	23.4	23.4	30.4	30.4	27.0	27.0	37.4	37.4
				H2T-h	9.0	9.0	11.4	11.3	13.2	13.2	16.0	16.0	16.0	16.0	20.6	20.6	20.4	20.4	24.6	24.6	17.2	17.2	17.6	17.6	19.2	19.2	22.0	22.0	24.4	24.4	30.4	30.4	27.0	27.0	37.2	37.2
	EMB-h	LI-h	GAS-h	H2T-l	10.4	10.4	10.8	10.7	12.5	12.5	14.8	14.8	16.4	16.4	18.6	18.6	19.6	19.6	25.8	25.8	21.4	21.4	25.2	25.2	26.4	26.4	30.2	30.2	31.2	31.2	29.2	29.2	32.8	32.8	31.0	31.0
				H2T-h	11.9	11.9	10.7	10.7	13.2	13.2	15.6	15.6	16.4	16.4	18.6	18.6	20.0	20.0	26.2	26.2	21.4	21.4	25.2	25.2	27.4	27.4	31.0	31.0	31.6	31.6	29.8	29.6	32.8	32.8	31.0	31.0
			GAS-l	H2T-l	11.9	11.9	11.6	11.5	13.2	13.2	15.6	15.6	16.8	16.8	19.2	19.2	20.2	20.2	26.2	26.2	21.6	21.6	25.2	25.2	27.6	27.6	31.2	31.2	32.0	31.8	30.8	30.4	33.6	33.1	34.6	34.4
				H2T-h	12.0	12.0	11.6	11.6	14.2	14.2	15.8	15.8	16.8	16.8	19.4	19.4	21.0	21.0	26.4	26.4	21.6	21.6	25.2	25.2	27.8	27.8	31.8	31.6	32.0	31.8	32.4	32.4	34.0	33.8	34.8	34.6
		LI-l	GAS-h	H2T-l	11.4	11.6	13.4	13.4	14.6	14.6	17.4	17.4	18.8	18.8	24.0	24.0	21.2	21.2	30.2	30.2	26.2	26.2	30.4	30.4	31.4	31.5	33.6	33.6	34.0	34.0	32.8	32.4	35.6	35.6	34.8	34.6
				H2T-h	13.0	13.0	13.6	13.6	15.2	15.2	17.6	17.6	18.8	18.8	24.2	24.2	21.4	21.4	30.8	30.8	27.6	27.6	31.4	31.4	33.3	33.2	33.8	33.8	34.2	34.2	33.4	33.4	35.6	35.6	35.4	35.2
			GAS-l	H2T-l	13.2	13.2	13.4	13.6	15.0	15.0	17.4	17.4	19.2	19.2	24.2	24.2	22.0	22.0	31.4	31.4	26.2	26.2	31.6	31.6	31.6	31.6	34.0	34.0	35.2	35.0	34.8	34.5	36.4	36.4	36.6	36.4
				H2T-h	13.4	13.4	13.6	13.6	15.4	15.4	18.4	18.4	19.2	19.2	24.2	24.2	22.6	22.6	31.8	31.8	27.6	27.4	31.8	31.8	33.2	33.2	34.6	34.6	35.0	35.0	35.1	35.1	36.4	36.4	36.6	36.6
OFF-l	EMB-l	LI-h	GAS-h	H2T-l	10.0	10.0	8.8	8.8	11.4	11.4	13.8	13.8	16.6	16.6	26.2	26.2	22.0	22.0	30.8	30.8	16.6	16.6	19.8	19.8	20.8	20.8	26.0	26.0	32.0	32.0	31.2	31.2	34.0	34.0	32.6	32.6
				H2T-h	10.0	10.0	9.0	9.0	11.4	11.4	13.8	13.8	16.6	16.6	26.2	26.2	22.0	22.0	31.2	31.2	16.6	16.6	19.8	19.8	20.8	20.8	26.0	26.0	32.0	32.0	31.2	31.2	34.0	34.0	32.6	32.6
			GAS-l	H2T-l	10.4	10.4	12.0	12.0	13.8	13.8	16.0	16.0	17.2	17.2	26.4	26.4	22.0	22.0	31.6	31.6	17.4	17.4	19.8	19.8	21.6	21.6	26.0	26.0	32.4	32.4	31.8	31.8	34.4	34.4	33.2	33.2
				H2T-h	10.4	10.4	12.6	12.6	13.8	13.8	16.0	16.0	17.2	17.2	26.4	26.4	22.0	22.0	31.6	31.6	17.4	17.4	19.8	19.8	21.6	21.6	26.0	26.0	32.4	32.4	31.8	31.8	34.4	34.4	33.2	33.2
		LI-l	GAS-h	H2T-l	11.4	11.4	13.2	13.2	15.0	15.0	19.0	19.0	20.6	20.6	31.0	31.0	28.0	28.0	34.4	34.4	20.6	20.6	24.4	24.4	25.4	25.4	32.0	32.0	35.8	35.8	34.2	34.2	38.0	38.0	35.5	35.5
				H2T-h	11.3	11.3	13.2	13.2	15.2	15.2	18.8	18.8	20.6	20.6	31.0	31.0	28.0	28.0	34.8	34.8	20.6	20.6	24.4	24.4	25.4	25.4	32.4	32.4	35.8	35.8	34.2	34.2	38.0	38.0	35.5	35.5
			GAS-l	H2T-l	13.6	13.6	15.8	15.8	17.4	17.4	19.8	19.8	21.6	21.6	31.0	31.0	28.0	28.0	35.0	34.8	20.8	20.8	24.4	24.4	25.4	25.4	32.6	32.6	36.0	36.0	35.2	35.2	38.2	38.2	39.0	38.0
				H2T-h	14.8	14.8	16.0	16.0	18.2	18.2	19.8	19.8	21.4	21.4	31.0	31.0	28.0	28.0	35.4	35.4	20.6	20.6	24.4	24.4	25.4	25.4	33.0	33.0	36.0	36.0	35.5	35.2	38.2	38.2	39.0	37.6
	EMB-h	LI-h	GAS-h	H2T-l	10.9	10.9	14.4	14.4	16.4	16.4	20.8	20.6	24.2	24.2	27.8	27.8	30.2	30.2	28.8	28.8	26.4	26.6	25.0	25.0	27.6	27.6	26.4	26.4	25.6	25.5	27.3	26.4	30.8	30.2	28.7	27.4
				H2T-h	10.9	10.9	14.6	14.6	16.2	16.2	20.6	20.6	24.2	24.2	27.8	27.8	30.6	30.6	28.8	28.8	26.6	26.6	25.0	25.0	27.6	27.6	26.8	26.8	25.5	25.6	27.3	26.4	31.2	30.2	28.7	27.4
			GAS-l	H2T-l	13.1	13.1	15.6	15.6	16.8	16.8	20.8	20.8	24.4	24.4	28.2	28.2	30.8	30.8	30.0	29.8	27.8	27.4	27.6	27.4	29.0	29.0	30.4	30.4	29.2	29.4	28.6	26.4	30.4	30.4	34.3	28.8
				H2T-h	13.2	13.1	15.4	15.4	16.6	16.6	20.6	20.6	24.4	24.4	28.2	28.2	30.8	30.8	30.0	30.0	27.8	27.4	27.6	27.6	30.2	30.0	30.4	30.4	29.2	29.4	28.6	26.4	30.4	30.4	34.5	28.8
		LI-l	GAS-h	H2T-l	16.6	16.6	19.6	19.6	20.8	20.8	27.6	27.6	28.8	28.8	31.0	31.0	33.6	33.6	32.2	32.2	29.7	29.6	28.4	28.2	30.8	30.8	30.0	30.0	29.4	29.4	33.2	30.2	34.7	34.0	34.2	31.2
				H2T-h	16.4	16.4	19.4	19.4	20.4	20.4	28.2	28.2	28.6	28.6	30.8	30.8	34.0	34.0	32.2	32.2	30.0	29.9	28.4	28.2	31.0	30.8	30.2	30.2	30.2	30.2	33.2	30.2	35.3	34.0	34.2	31.2
			GAS-l	H2T-l	17.4	17.4	20.4	20.4	21.5	21.6	27.6	27.6	28.8	28.8	31.6	31.6	34.4	34.2	34.2	33.6	31.9	31.0	32.0	30.0	33.2	32.6	33.2	31.0	33.0	33.2	32.1	30.2	34.5	34.2	36.1	32.5
				H2T-h	17.2	17.2	20.3	20.4	21.4	21.4	28.4	28.4	29.8	29.8	31.8	31.8	34.2	34.2	34.4	34.2	32.0	31.1	32.3	32.2	33.6	33.6	33.6	33.6	33.0	33.2	31.9	30.2	34.5	34.2	36.1	32.5

Figure E.1: 2040 - investment decision - heat map of electrolysis capacity.