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Distribution grid planning considering sector coupling and waste heat recovery

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Abstract

This thesis work investigates and provides an analysis of the potential benefits of an electricity - gas - heat integrated energy system, putting extra focus on the waste heat potential from fuel cells and electrolysers.
The main focus is given to the low-voltage distribution grid level, and a case study is presented for the Drechtsteden subnetwork operated by Stedin, which, together with the IEPG department at TU Delft, is the promoter of this study. The novelty items of this work consist in the analysis of the waste heat potential of hydrogen conversion assets connected to a district heating network along with the inclusion of electricity and hydrogen markets, all in the contest of an energy system optimization.

The integration between these three energy sectors is assumed to be chiefly driven by the operation of electrolysers and fuel cells. Two other main assumptions set the base for this work: first, the gas sector is assumed to be entirely repurposed to operate with hydrogen and, secondly, the waste heat coming from fuel cells and electrolysers is assumed to be the main thermal energy input of a district heating network. An electricity and a hydrogen market have also been modelled to simulate the interaction of this region with the external grid.
The analysis is carried out by means of a linear optimization algorithm coded using oemof, an open source python package for multi-energy system modelling and optimization. Most of the input data (i.e. energy demand and generation profiles) comes from the Integrale Ifrastructuurverkenning 2030-2050 study from TenneT, Gasunie and the Dutch DSOs, which has been regionalized for the Drechsteden region is order to optimize the investments on the main energy assets (transformers, hydrogen substations, electrolysers, fuel cells, batteries) needed to run the future energy system.

An optimal system configuration is also calculated for a "reinforcement" scenario, in which energy sectors remain independent, and a comparison with the system integration scenario is presented. The overall system costs appear to be only about 5% lower for the system integration scenario. The costs imputable to assets is higher with system integration due to the addition of expensive hydrogen conversion assets, but, in this scenario, the operation on the energy market (driven chiefly by hydrogen exports) is more advantageous. Finally, a sensitivity analysis on the share of heat demand to be satisfied by district heating and on the price of batteries is carried out, along with an investigation on the effect of adding thermal storage to the system.

Acknowledgements

This thesis marks the end of one of the most valuable, exciting and challenging learning experiences of my life so far: my master in Sustainable Energy Technology at TU Delft.
During these two years I have had the fortune of receiving an excellent education on many topics related to one of the most faceted systems on the planet: the one keeping the lights on.
The most interesting part has surely been learning about the many challenges of this system, and my desire, as a student, to give my small contribution has culminated in this thesis work.

Looking at the energy system from a very wide perspective, this work enabled me to gain invaluable insights and knowledge. On this, the help of professor Milos Cvetkovic made all the difference in untangling the complexity of this approach.
I would also like to thank Arjan van Voorden and Arjen Jongepier for their precious help and constant feedback, and for giving me the chance of being introduced to an exciting corporate environment where the energy transition is being put into practice.

Finally, I would like to thank my family and friends for their continuous support through this long learning journey. If I will be able to fulfill my dream of giving my contribution to the energy transition, it will be first and foremost thanks to them.

Alessandro Pozzetto
Delft, 09/10/2022

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List of Abbreviations

DH	**D**istrict **H**eating
PEM	**P**roton **E**xchange **M**embrane
FC	**F**uel **C**ell
PEMFC	**P**roton **E**xchange **M**embrane **F**uel **C**ell
LCOH	**L**evelized **C**ost **o**f **H**ydrogen
LCOE	**L**evelized **C**ost **o**f **E**lectricity
VRES	**V**ariable **R**enewable **E**nergy **S**ource
CHP	**C**ombined **H**eat **P**ower
LP	**L**inear **P**rogramming
MILP	**M**ixed **I**nteger **L**inear **P**rogramming
WACC	**W**eighted **A**verage **C**ost of **C**apital

1 Introduction

1.1 General background

One hundred and ninety six countries signed, in 2015, a treaty on climate change. With this, they pledged to limit the increase in the global average temperature to less than 2°C within the end of the century [1].

To reach this goal, many countries are aiming at becoming climate neutral by 2050, including the Netherlands.
These ambitions, coupled with technological advancements and evolving market regulations, are leading to a profound restructuring of the energy system. The main goal of this restructuring is to reduce (or bring to zero) the emissions footprint of the energy system while maintaining security of supply for the customers.
Currently, one of the main ways to achieve this goal is by increasing the share of renewable generation in the electricity mix. Given the intermittent nature of most renewable sources (especially wind and solar), increasing the flexibility of the energy system by means of energy storage and, more generally, with the integration of different energy systems has grown in importance.

Distribution grid operators, such as Stedin, also face numerous challenges in the planning of their low-voltage electrical network. As well known by now, this is mainly due to two expected substantial changes. First, electrical demand is bound to increase substantially giving rise to potential congestion problems. Secondly, the increasing share of distributed renewable sources will modify the power flows, which were initially uni-directional, to more frequent situations of reversed power flow from distribution to transmission level [2].

Therefore, it appears evident how the planning of the numerous investments that will have to be carried forward to achieve a future-proof energy system is a pivotal point in the strategy of most grid operators. In fact, the decisions taken in the upcoming years will greatly impact the pathway to the envisioned climate-neutral energy system of 2050.
For instance, in the Netherlands, the TSO and the DSOs work together to produce periodical analyses on how an integrated and climate-neutral energy system could look like, in order to try to steer public and private investments in such a direction [3].

1.2 State of the art

Due to the stated importance and interest revolving around the topic of energy system planning, several works have appeared in literature in the past years, and a great output is still underway at the present moment.

Most of these researches present operational and investment optimizations (further details of this definition in chapter 3) of energy systems with a certain degree of integration, often an electricity-gas one [4] [5] [6] [7].
Some other works focus mostly on the electrical sector, usually using a more detailed description of its technical aspects and studying its optimal relation with battery energy storage [8] [9] [10].
Some works also take district heating into the equation, even though this is mostly considered with a low level of detail and without optimization techniques [11] [12].
The inclusion of energy market in these types of optimization analyses is not so frequent, with some examples considering, for instance, a price formation based only on limited, local data [13] [14].

1.3 Research questions

The objective of this thesis is to develop an investment-operational optimization with to goal to gain insight into the integration of electricity, gas and district heating at distribution level.
The analysis will be applied to the Drechtsteden region (400 square kilometers located south of Rotterdam) and it will rely on the Integrale Infrastructuurverkenning 2030-2050 study for most of the input data.
The main research question is:

- *How can the flexibility provided by an electricity-gas-heat integrated energy system lead to advantages in distribution grid planning, as opposed to considering an electricity only system?*

Furthermore, these three further sub-questions better define the scope of the research:

- *Which modelling aspects need to be considered when designing an investment & planning optimization model for such an integrated energy system, and how are these currently represented in literature?*

- *What is the potential role played by waste heat recovery from hydrogen conversion technologies (i.e. electrolysers and fuel cells), if combined to a district heating system?*

- *How sensible are the results when considering the different long-term climate-neutral energy systems scenarios developed by Netbeheer Nederland? How does the optimal system infrastructure vary between these scenarios?*

1.4 Structure of the thesis

A literature review on the technical aspects of integrated energy system is presented in chapter 2, along with specific discussions for each of the three energy sectors under analysis (electrical, gas and heating).
Then, chapter 3 presents a literature review specific to optimization techniques applied to energy system modelling. Chapter 4 how the model for this thesis is constructed and the main assumptions behind it. Chapter 5 introduces the case study and the input data used for the calculations. Chapter 6 presents the results of the analysis and, finally, the report is concluded in chapter 7.

2 | Integrated energy systems

This chapter presents an overview of the literature review findings regarding integrated energy systems and the different sectors which constitute them. After a brief introduction in section 2.1, section 2.2 and 2.3 describe the electrical and gas network and the changes that are needed and forecasted in view of a deeper system integration.
Finally, section 2.4 digs deeper in the heating sector, in particular in district heating, while also providing an overview of the hydrogen conversion assets which, as it will be seen in chapter 4, will play a pivotal role in the energy system that will be modeled in this work.

2.1 Multi energy systems characteristics

With the incorporation of variable, distributed renewable energy sources, the shift to a sustainable future poses a challenge to current energy systems. On a technical level, multi-energy systems may provide the flexibility needed to close the demand-supply imbalance.
A MES is defined as a system whereby different energy sectors, such as electricity, heat, natural gas, and hydrogen "optimally interact with each other at various levels" [15] (visualization: figure 2.1).
MESs provide various technical, economic, and environmental advantages over separate energy systems. First, combining diverse energy sectors could be a good way to increase the flexibility of the energy system while also improving the overall level of optimization. The various conversion options allow for system optimization through the substitution of alternative energy carriers. To address different sorts of demand, alternative sources might be used. For example, during periods of high wind or solar production, a MES would allow this electricity to be used to meet electrical or heating demand, or to make hydrogen through electrolysis, enhancing flexibility. Therefore, it's clear how by broadening the options for substituting one energy carrier for another, VRES adoption can be boosted [16]. The scale of complexity of MES and MES models can vary greatly, starting from a simple electricity-gas interconnection to more sophisticated and cross sectorial descritpions, such as the one presented in [17]. The energy system modeled in this work can be considered a MES, since the electricity, hydrogen and heat sectors are interconnected and cross-sectoral conversions between these carriers can take place (as will be explained in more detail in the coming chapters).

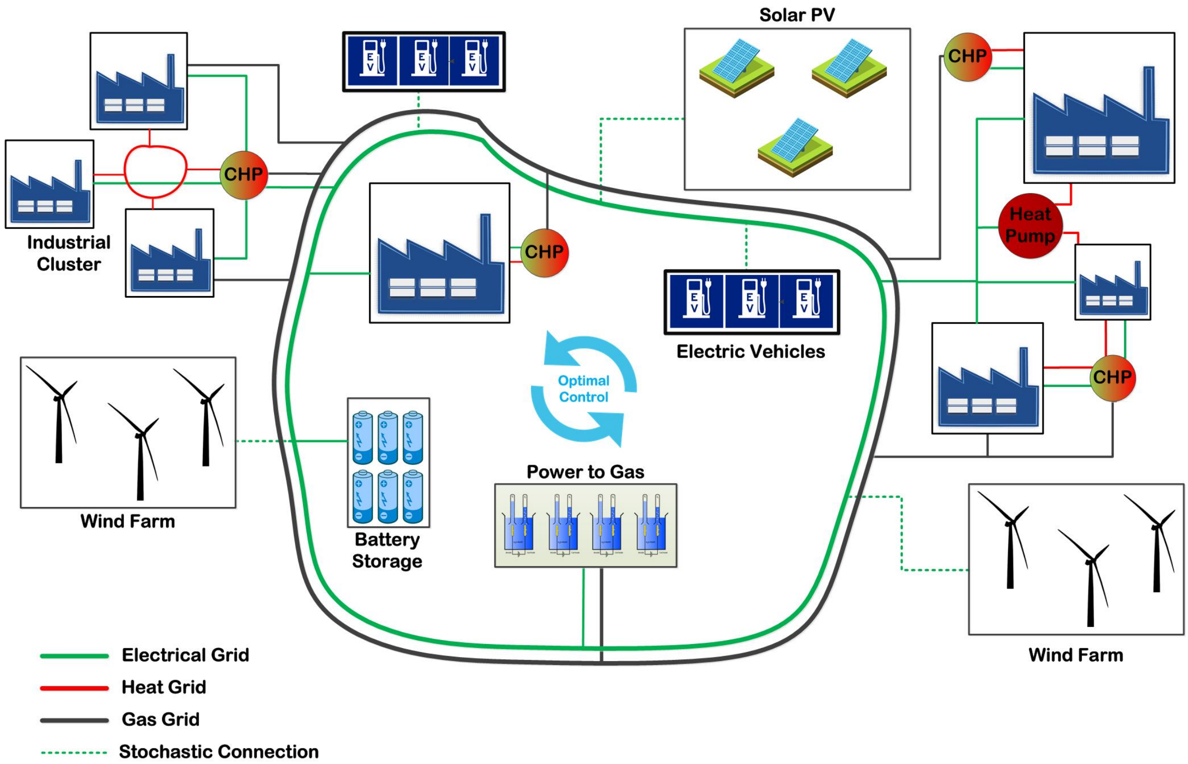


FIGURE 2.1: Electricity-Gas-Heat MES applied to industrial parks [18]

2.2 Electrical network

Generation, transmission, distribution, and consumption are the four major components of the electrical power system, each with its own set of control and protection mechanisms.
Generators and loads are distributed around the network at various voltage levels, with big conventional plants being positioned at the highest voltage and smaller generators and loads being located at lower voltage levels. Because electrical losses are smaller when power is transmitted at higher voltages, transmission grids typically work at high voltage levels (such as 150 kV) since it is more cost effective (per transported unit of power). However, higher-voltage equipment is often more expensive, and this trade-off makes it more cost-effective to transfer bigger amounts of power at higher voltages, which is typically done across longer distances.
However, the advancement of distributed generation (DG) technology, particularly renewable wind and solar energy generation, has resulted in considerable quantities of generation at the distribution level. Distributed renewable production is predicted to increase as a result of climate policy, notably with aims for near carbon neutrality by 2050 [8]. The model presented in this thesis explores this possibility, since large capacities of local distributed generation will be considered.

Traditional power plants have larger capacities, whereas DG units are typically positioned closer to the consumers. Wind turbines, solar panels, and small-scale hydropower are common DG technologies, but these distributed generation can also be based on fossil fuels, such as low power gas turbines. In such a decentralized and non-dispatchable power system, a mismatch (i.e. a deviation between demand and supply) can occur more frequently, and can potentially cause instability, damage equipment and even lead to outages. Storage technologies, flexible generation, demand-side management, and transmission infrastructure are among the alternatives being investigated to improve the reliability, affordability, and environmental acceptability of energy systems with high VRES uptake [19].

Along with an increase in distributed generation, a very steep increase in electrical demand is also forecast. For example, at the residential sector large capacities of heat pumps will be installed, substituting gas boilers; at the industrial sector many energy-intensive processes are likely to be electrified to some extend and, finally, the transport sector is already seeing and will continue to see a dramatic increase in electrically-powered vehicles in its fleet. As it can be observed in figure 2.2 (TWh on y-axis) this increase in electrical demand could reach a 25% from today's level in just 8 years from now.

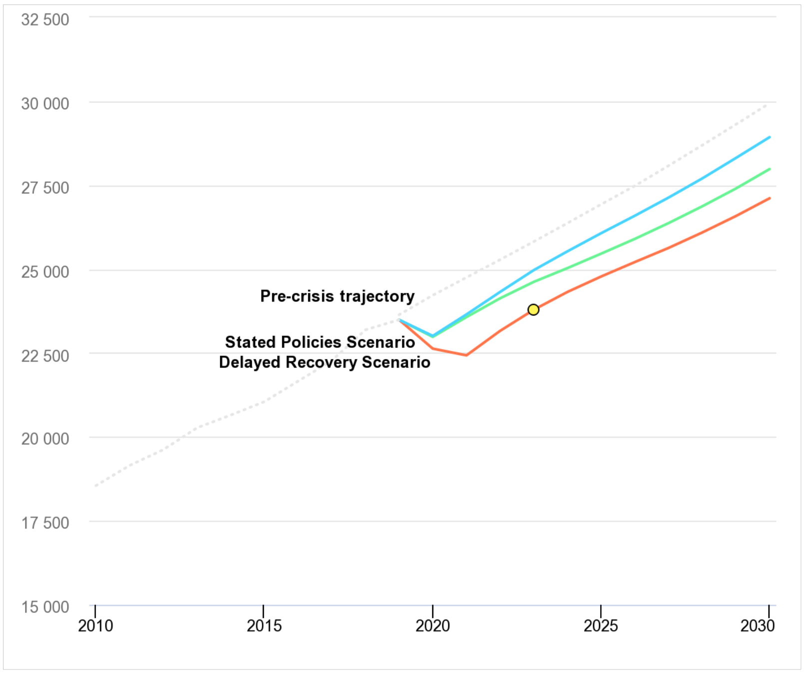


FIGURE 2.2: Global electricity demand forecast [20]

These technical considerations, coupled with the fact that the electrical demand in the coming decades will dramatically increase, makes it also clear how infrastructure strengthening will play a crucial role. In fact, infrastructure built years or decades ago was in many cases engineered for very different peak volumes both at the generation and load side. If no action is taken, more and more bottlenecks will arise in the grids, making further efforts towards the decarbonisation of the energy sector more difficult (due to the impossibility to add more electrical loading to the lines) and, in the worst case scenario, even to system failures.

On a national scale, it is possible to identify three main parameters that can have an impact on grid investments:

- Landfall points for offshore wind power
- Size and location of large demand clusters (such as industries, cities)
- Power to gas locations: the key long-term flexibility resource
- Location of batteries and quick-start peak power stations

Detailed reinforcements plans are already underway, as it can be seen in figure 2.3:

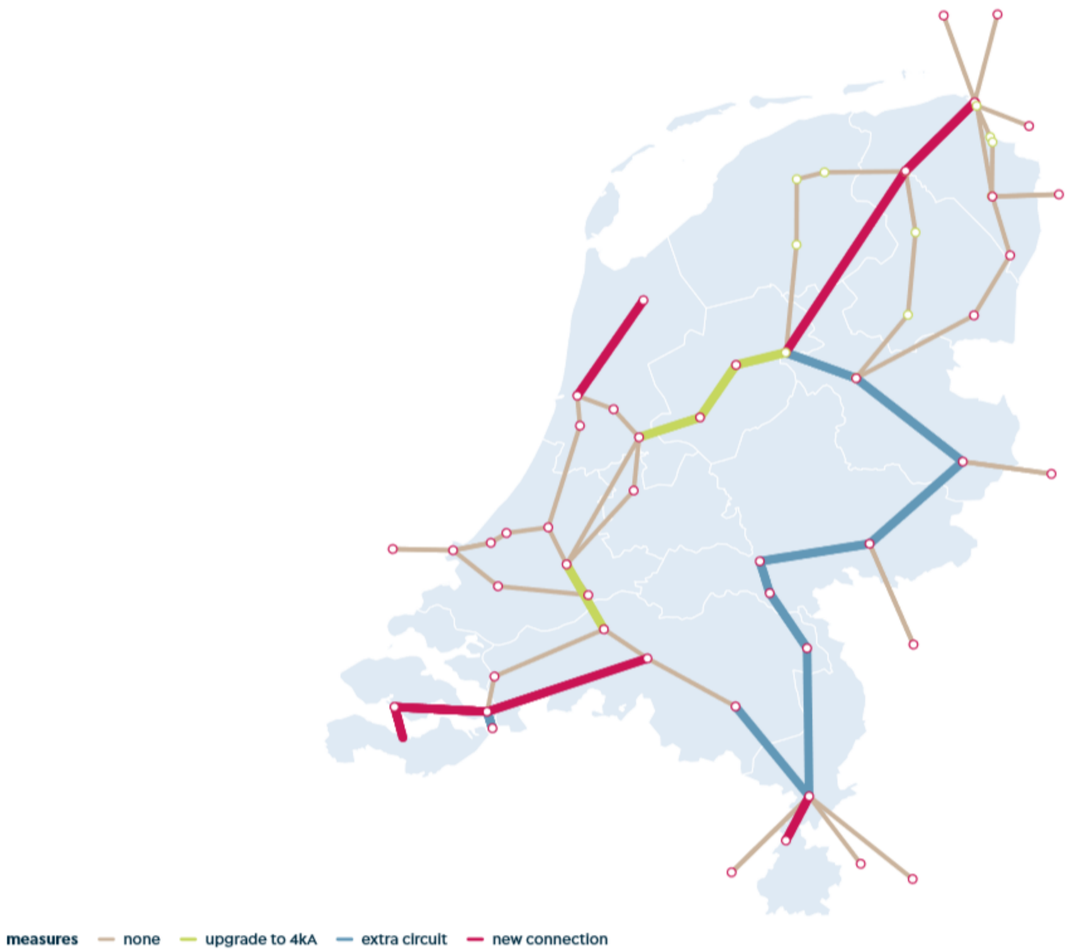


FIGURE 2.3: 380kV network expansions already planned by TenneT [21]

The distribution grid (i.e. 66kV or lower) will, of course, also have to develop in order to be able to cope with the increasing loads. The largest investments

are forecast especially in the case of a sharp rise in distributed small-scale renewable generation, since, as already mentioned, these are usually connected directly to the low-voltage grid [3]. Increased electrical demand for appliances such as heat pumps and electric vehicles will also put additional strain on the distribution grid.
At this low-voltage level, the two main modifications that can take place are increasing the capacity of the current substations (by placing additional transformers) and/or making new cable connections or strengthening the existing ones [21].

As it will be described in more detail in chapter 3, deciding on these investments is not an easy and straightforward task, as it involves a consistent number of variables to be optimized. This is the reason why in current literature, several publications dealing with the planning of distribution grids have started appearing. The objective is to use and improve so-called *optimization algorithms* in order to make educated decisions on how and where to invest in the grid.
The main evolution in this field consists in trying to include more detailed simulations; this can be both from a technical point of view, considering for instance more components, electrical losses and detailed power-flows [22] [23] and/or more detailed representations of electricity markets and prices [24].

Another share of the literature in this field analyses case-studies with specific characteristics. Among the many possible examples, a number of studies focus on the design of an electrical system integrated with different form of storage to achieve self-sufficiency in isolated communities. While the problems of these case-studies are different from the already discussed grid reinforcements at national level, they still show the advantages of energy system integration. For instance, [7] applied a MILP optimization on a VRES-BESS-H2 energy system for a small island. While the current electricity price on this island (which is powered by generators powered with imported fuels) stands at a very high 0.86 €/MWh, such an integrated system could be able to bring the LCOE to 0.4 €/MWh.

2.3 Gas network

Natural gas currently plays a very important role in the energy mix of the Netherlands. In fact, natural gas provided 51 percent of power in 2018 and 90 percent of private domestic heating [25]. Given the importance of natural gas in the Netherlands, there is a vast gas infrastructure network. This includes about 130,000 kilometers of gas pipelines with connections to 95% of homes. Gas is carried throughout the country by Gasunie, the gas TSO, and distributed to end-users via the gas distribution network. On top of managing the low-voltage distribution network, Stedin manages also the gas distribution network. To transfer significant amounts of gas over long distances, the gas transmission network uses high pressures (up to 87 bar), similar to the higher voltages used in the electric transmission network. On the connection points with the distribution network this pressure is brought down, usually to 8 bar, for its feeding into the Stedin network where it's then depressurized further for the final delivery to the consumers [26].

Given the size of available natural gas infrastructure and the desire to phase out natural gas in the next decades in favor of more sustainably derived gases, repurposing the existing infrastructure is being discussed. Hydrogen, in particular, is expected to play a significant role in future carbon-free energy systems, both as a feedstock for industry and as a fuel (including for mobility and heating).
Hydrogen is categorised as grey, blue, or green depending on the process of manufacture. The majority of hydrogen used today is grey hydrogen, which is created via steam methane reformation (SMR), which involves reacting methane with high-pressure steam to produce hydrogen and carbon dioxide. Grey hydrogen that has had most of its related carbon dioxide emissions caught and stored, is referred to as blue or low-carbon hydrogen. However, the most environmentally friendly method of producing hydrogen is to split water into oxygen and (green) hydrogen using electricity generated from renewable sources [27].

2.3.1 Hydrogen storage and transport

Hydrogen is expected to play a central role in the future energy system of the Netherlands also thanks to the potential storage capacity exploitable in underground salt caverns in the north of the country. On this regard, several studies have already been carried forward such as [28]. The expected energy capacity for underground hydrogen hydrogen is 43.3 TWh in salt caverns and 277 TWh in depleted gas fields.
To exploit this potential, and, at the same time, to make wise use of the existing natural gas infrastructure, Gasunie is focusing on the development of a national hydrogen transport network that could be operational before 2030 with capacities in the range of 10-15 GW.

FIGURE 2.4: Dutch Hydrogen Backbone [29]

This transport network will be established in phases and will follow the development of supply and demand in the market: from connections at and between large industrial clusters to national connections and to hydrogen storage in the north and east of the country. Parts of this hydrogen transport network and hydrogen storage could become available in the period from 2023 to 2030. Some parts of the transport network could already be realised around 2025 (especially in the north-east of the country, in the port of Rotterdam and possibly Zeeland). For a national coverage of the hydrogen transport network, existing pipelines can largely (approximately 85%) be used; approximately 15% of the remaining pipelines will have to be newly constructed. The resulting connecting network of approximately 1,000 km (the 'hydrogen backbone') can also provide international transport, for instance with connections to the Ruhr area in Germany, to Belgium and to large-scale offshore facilities in the North Sea [3].

After having ascertained that an hydrogen high-pressure distribution network is not only completely feasible but also under active development, an investigation has been carried forward regarding the soundness of assuming also an hydrogen low-pressure distribution network. On this, an analysis made in [30] suggests that repurposing the current methane distribution network will not have severe effects regarding the quality of delivered hydrogen after coming to the following results:

- The amount of contaminants that might affect the quality of hydrogen does not breach regulations for connecting hydrogen boilers
- Safety is not deeply affected since the flammability limit due to oxygen penetration would still be 10 times lower than the allowed limit
- It is almost impossible to achieve a carbon monoxide concentration high enough to hinder the functioning of PEMFCs

All the considerations presented in this section constitute the reason why the gas network considered in this work is assumed to be entirely repurposed to hydrogen.

2.4 District heating and H_2 waste heat integration

As mentioned, hydrogen is predicted to play a significant role as a future energy carrier in the transition to renewable energy systems.
Distribution heating (DH) networks will also be critical in a future sustainable energy system's macroeconomic energy efficiency. One of the key technical advantages of DH is that they can provide clients with thermal energy and hot water at the exergetically optimal temperature level by utilizing low-grade heat which can also be absorbed from residual flows (waste heat) [11].
Typical generation sources for district heating are CHP typically fueled with gas or biogas, waste heat from industrial processes, burning of municipal waste residues and, where geographically possible, geothermal sources [31].

Even though the integration of district heating and hydrogen conversion technologies (i.e. mainly fuel cells and electrolysers) is not yet widely spread, some initial publications praising the benefits of such configurations have started appearing in literature [12][32][33].
In fact, although the efficiency of such assets is rapidly increasing as technology progresses, a considerable share of the power involved in the electrochemical reactions ultimately is released as heat. In the case of fuel cells this is due to the fact that an exothermic reaction is involved inside the cell. Electrolysis is technically an endothermic reaction but actual applications are still able to provide waste heat since the reaction is typically run above the so-called *thermoneutral voltage*, i.e. the voltage at which the reaction proceeds at constant temperature [11].
Since, as it will be explained later, there is a defined trend towards large-scale installations of hydrogen conversion devices, the interest behind the useful and smart integration of the heat thereby produced is certainly destined to grow in the future.

2.4.1 Stationary fuel cells and electrolysers

Fuel cells and electrolysers are probably the most fundamental technologies in the integration between the electricity and gas (hydrogen) sector. In fact

these assets are used to operate the well known Redox reaction
$H_2O \leftrightarrows 2H_2 + O_2$ (occuring to the left during electrolysis and to the right during fuel cell operation).
Capital expenditures are currently the most limiting factor in the large-scale adoption of fuel cells systems but, in the following decades, thanks to technological progress and wider adoption (resulting in a stronger economy of scale) these are expected to drop considerably, as it can be observed in figure 2.5 (columns refer to the CAPEX evolution while the lines refer to the efficiency).

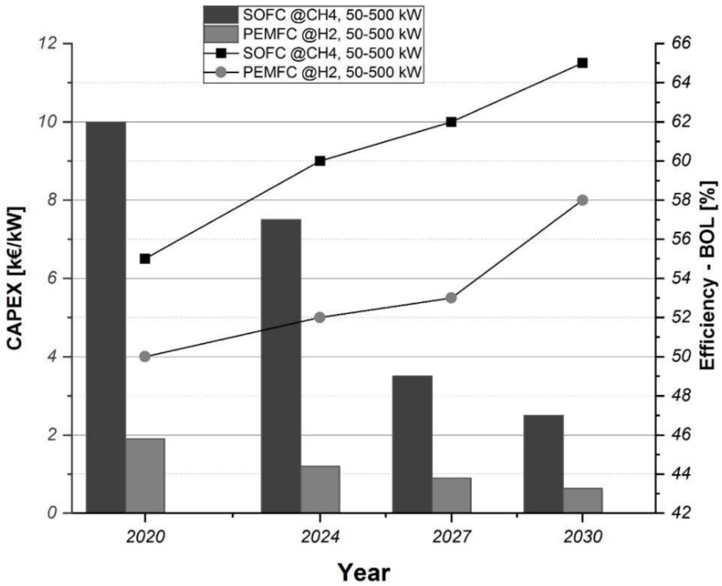


FIGURE 2.5: PEMFC and SOFC CAPEX projection [34]

The scalability of these assets is surely one of their great strength points. For instance, fuel cells in the range of tens of kW are developing in the hydrogen mobility market, but it is possible to produce systems with far more output: when the power rating exceeds 200 kW, these are referred as *large capacity* fuel cells or electrolysers. Due to the size of these assets, large capacity systems are almost always stationary.
The cumulative installed capacity of such systems is not yet relevant due to the mentioned high costs and also due to the fact that grid-scale usage of hydrogen is currently still a niche market. However, as seen, both these drawbacks are forecast to become less and less insurmountable in the coming 20 years.
Therefore due to the projected growth in the cumulative installed power of large-scale stationary fuel cell and electrolysis systems [35], this thesis work will put some special focus on the waste heat potential of these assets.
In particular, proton exchange membrane (PEM) and solid oxide (SO) technologies are expected to gain the largest market shares in the coming decades [34], and, since the time horizon on this work's analysis is 2050, these two will be the technologies under consideration. Table 2.1 summarises their main

characteristics.

TABLE 2.1: PEM and SO cells characteristics [32] [36] [37] [38]

Technologies	Electrical efficiency	CHP efficiency	Operating temperature
PEMFC	52-57%	87-95% (Low temp) 85-95% (High temp)	60-80°C (Low temp) 100-200°C (High temp)
SOFC	60-65%	90%	700-1000°C
PEMEL	70%	97%	50-80°C
SOEL	80%	100%	650-900°C

2.4.2 4th generation DH networks

The high operating temperatures of solid oxide cells make them particularly appealing if coupled to industrial sites, which are amongst the top consumers of high-grade heat [33]. However, since the geographical area under analysis is, as it will be described in more detail in chapter 5, mostly residential, proton exchange membrane cells will be the selected technology.
In fact, the next evolution aimed at improving efficiency in district heating networks will be a considerable lowering of the operating temperatures. Lower temperatures mean lower losses and a better integration of low-exergy sources, such as solar thermal energy and heat pumps along with the already mentioned PEM cells. Recent prototypes of 4th gen DH grids show up to threefold heat efficiency improvements [39].
These networks will mostly be used to provide low-temperature heat for domestic spaces and domestic hot water. Therefore, the mentioned development oriented to decrease their temperature must proceed in parallel with considerable efficiency improvements in the built environment [40].

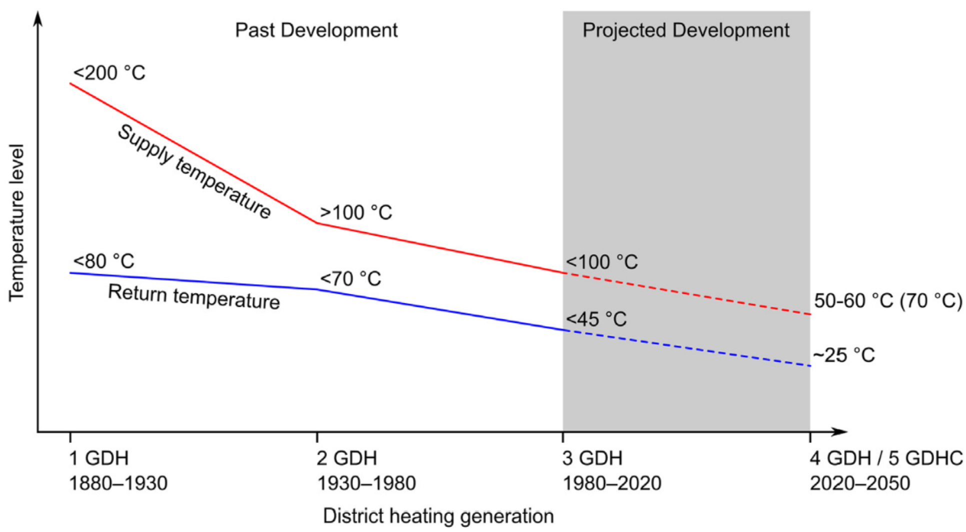


FIGURE 2.6: DH operating temperature development [11].

Another reason for examining the integration potential of fuel cells and electrolysers in district heating is the favourable seasonality that would arise in such a system. As it can be seen in table 2.1, fuel cells provide the greatest heat output between the two and, in addition, stationary fuel cells will typically be used more in winter (to cover peak electrical demand when renewable output is low) when also heating demand is high.
Instead, electrolysis will probably be used more in summer to exploit the excess renewable power, and the fact that their heat output is lower compared to the one of fuel cells is of less importance due to the lower heat demand during the warm months of the year [11].

Currently being the cheapest storage option, thermal storage is also expected to play a role in stabilising DH networks, aiming at matching the heating demand and supply.
Thermal storage can be divided in two main categories: short-term and long-term. In the first case, the storage is meant to satisfy the daily fluctuations, while the long-term one is used to balance seasonal variations.
Thermal storage can be also divided in two other main categories based on the physical principle behind their functioning: sensible heat storage and latent heat storage.
The most common application for sensible heat storage is storage in tanks, a mature and simple technology in which a fluid, typically water, serves as a thermal buffer mostly in the short term. It has a relatively low storage density.
Long term storage in the form of sensible heat is often in the form of tanks or pits, aquifers and boreholes (which use the thermal capacity of soil) [41].
Latent heat storage is, on the other hand, a recent technology with ongoing research. By absorbing heat gain during warmer daytime via melting and releasing the stored thermal energy during colder nighttime when it solidifies, PCMs (phase changing materials) can be used to reduce and time-shift thermal load peaks. The main difference is that the storage density is much higher compared to sensible heat, because here heat is supplied to change the phase of the storage material [31].

3 Modelling of distribution system planning

This chapter describes the methodology behind the planning of the expansion of distribution networks, and how this process can be translated and analysed with the help of optimization techniques.
Section 3.1 starts by illustrating the different approaches in building an energy model, followed by the most important aspects that should be thoroughly analysed when specifically constructing an optimization model.
Section 3.2 describes how the different optimization algorithms and approaches treat the problem; a discussion on how to reduce the complexity of these is also provided.
Finally, section 3.3 gives an overview of the ample panorama of tools that can be used to execute these analysis.

3.1 Network expansion planning

Modeling methodologies for energy networks can be classified as top-down or bottom-up. Top-down approaches try to provide a more economically and holistic perspective on an energy system, often by simplifying and aggregating its components. Bottom-up models, on the other hand, incorporate greater technological detail, allowing for broad forecasts of future energy supply and demand, as well as the specific contribution of various technologies. However, it should also be noted that the greater technological detail of bottom-up models necessitates more thorough data inclusion in the model, which frequently demands the addition of certain assumptions to make it tractable [42].
Since, as it will be described in more detail in chapter 4, the formulation of this thesis' model requires a certain degree of technological details to be included, from now on the focus will be given primarily to bottom-up models.

Bottom-up models can be further categorised in different types, such as simulations, partial equilibrium, multi-agent and, finally, the scope of this thesis, i.e. optimization models. An optimization problem's theoretical foundation is to find the best solution to a given objective (either minimizing or maximizing) using particular decision variables under various constraints. Optimization models are regarded as robust because they allow for the incorporation of high levels of detail in techno-economic characteristics, making them well suited for analyzing potential future energy system transitions. Although it leads to an unique solution, and this "perfect foresight" trait could be considered a drawback, optimizations are still very valuable in that they allow for one or more *ideal benchmark scenarios* to be formed [43].

It is possible to further categorize optimization models based on a number of relevant aspects. Table 3.1 presents the 7 most important categories.

TABLE 3.1: MES modelling aspects [44]

Aspect	Categories		
Modelling scope	Planning	Operation	
Optimization criteria	Environmental	Economic	Technical
Optimization formulation	LP	MILP	Heuristic
Spatial resolution	Building	District/Region	(Inter)National
Time horizon	Short	Medium	Long
Step-size	Minute	Hourly	Weekly, etc...
Detail level	Black-box	Grey-box	White-box

Going in more detail into the ***modelling scope***, expansion planning or design refers to decisions on future infrastructure improvements, such as new investments, while operation planning includes decisions like dispatch and maintenance in the context of an existing system.
Typically, system planning processes begin with the development of future demand and generation scenarios, followed by the determination of how to (best) alter current infrastructure to suit future power system needs. The timing, location, and capacity of each alteration can all be part of the planning process.
Typically, the purpose of distribution companies' long-term planning is to reduce network investment and operational expenses while respecting technical constraints. However, different ***optimization criteria*** can be chosen, such as CO_2 minimization or maximization of RES utilization.
Regarding the ***optimization formulation***, the problem of distribution expansion planning (DEP) is generally a mixed-integer nonlinear programming (MINLP) problem involving nonlinearity, which makes converging to a solution challenging and computationally intensive.
Various models and methodologies have been used to address the primary distribution network expansion planning challenge over the years. The DEP problem is generally being solved using two types of optimization approaches: conventional and meta-heuristic optimization methods. Heuristic algorithms can be seen as a way to mimic natural processes; they don't require an explicit formulation of the objective but, instead, a so-called "solutions population" is evolved to better ones by using a fitness function. However, although meta-heuristic approaches are relatively simple to implement, their optimality cannot be guaranteed [45]. Conventional optimization methods

(such as LP and MILP), on the other hand, are difficult to build, but they can be resolved with off-the-shelf optimization algorithms and provide guaranteed results. As previously stated, the DEP problem is a nonlinear problem that may be transformed into a (mixed-integer) linear programming problem with the inclusion of some reasonable assumptions [22]. Compared to LP, MILP formulations have the possibility to include the so-called "candidate investments" (i.e. new transformers, cables, etc. with pre-determined sizes/characteristics). MILP optimizations use binary variables associated to these candidates, which can therefore be chosen (or not) by the algorithm during its execution.
Apart from the self-explanatory ***spatial resolution, time horizon and step-size***, an important modelling aspect regards the ***detail level*** of the different elements involved in the optimization algorithm. In fact, energy transmission over networks can be modeled, depending on the application, at three degrees of detail: black-box, grey-box, and white-box. The term "black-box" refers to data input-output models that don't include any representation of the physical processes under exam. In general, black-box models are simpler and easier to compute (for instance, flows do not include losses). White box models are more detailed and take physical principles into account when calculating load flows and conversion efficiencies. Typically, in these models network flow losses are integrated as a function of the corresponding flow (based on conservation laws); this produces more accurate results but however, as can be expected, the introduction of these non-linearity can severely affect computing time [46]. Grey-box models place themselves in the middle, typically including some level of complexity while keeping the computational effort relatively low.

3.2 Executing the optimization

As briefly mentioned earlier, optimization problems are defined by an objective function to be minimized or maximized and decision variables subjected to a certain set of constraints. Decision variables can be varied freely or, like in the previously mentioned MILP formulation, only to 0 and 1 in the case of binary variables. A general formulation of an optimization problem is presented in equation 3.1

$$\begin{aligned} \min_{x} \ f_i(\mathbf{x}) \ \ i = (1,2,...,I), \\ s.t.\ h_j(\mathbf{x}) = 0 \ \ j = (1,2,...,J), \\ g_k(\mathbf{x}) \leq 0 \ \ k = (1,2,...,K), \\ \mathbf{x} = (x_1, x_2, ..., x_n)^T. \end{aligned} \tag{3.1}$$

Where $f_i(\mathbf{x}) h_j(\mathbf{x})$ and $g_k(\mathbf{x})$ are, respectively, the objective function, the equality constraints and the inequality constraints, and are all functions of the decision variables' vector $\mathbf{x}$.
Regarding the solution of these problems, and important distinction must be

made between convex and non-convex problems. The first type (such as LP) the convergence to a solution is always guaranteed while this doesn't hold for non-convex ones. Furthermore, there can also be a difference in the type of input parameters, which can be fixed (deterministic formulation) or varying within a fixed range or probability distribution (stochastic programming) [19]. As it will be described better in chapter 4, this thesis' model will be a LP with a deterministic formulation, therefore this means that its solution will be the global optima, and multiple iterations of the algorithm will lead to the same result (because of the fixed input).

As mentioned, the solution space for linear programming problems is convex, ensuring convergence to the global optimum. The simplex and interior point methods, which take advantage of the features of the convex solution space, are two mathematical strategies for solving linear programming problems. Another advantage of linear programming formulations is that they can immediately identify infeasibility. Non-linear programming problems, although they can provide with more accurate representations of physical problems, are typically solved iteratively, using direct or gradient-based approaches. Newton's method is suitable for the special case of non-linear programming problems called "quadratic problems" [47].

3.2.1 Reducing computation time

More complexity in the models obviously leads to a longer computation time, therefore, many scientific works dealt and are dealing with techniques to reduce this waiting time as much as possible. This is particularly useful in the case in which many optimization runs are needed, for instance to produce a refined sensitivity analysis of some parameters.

When considering energy system models, one of the greatest sources of computational burden is the amount of variables that have to be created and optimized. This is due to the fact that, typically, this type of models represent a full year with 8760 time steps.
An initial approach to reduce computational time could be to ignore network constraints and the charge/discharge behaviour of the assets, while keeping only the energy balance constraints. A step further, as done in [48] could be a two-stage optimization in which, after the first, simplified, optimization, a second "day-ahead" run is performed using the input from the previous execution to provide detailed results only for the limited number of time steps that make up a single day.

Bi-level optimizations are another refined technique in which the full optimization problem is split in two levels, usually called "upper" and "lower". In bi-level approached, each of the two levels of the model has its decision variables and objective functions, which are affected by the evolution of the variables of the other level. At the same time, the execution of the decisions happens in a sequential fashion, from the higher to the lower level [49]. This technique has been applied by [50], in which the energy modelling has been divided in a upper level of planning scheme considerations (such as costs of installation, operation and maintenance), while the lower level optimized the operation of the system (with objective such as peak load shaving, volatility restraint, improving reserve capability of storage systems).

Another, often used, method to reduce run-time is to *cluster* the input data in so called "representative days". The selection of these "representative days" can be done in different ways. For example, [51] proposed a method in which the selection of the clustering is done via a MILP algorithm. The goal of this optimization is to minimize the difference of the duration curves of the entire year and the representative year for each of the time series. Then, a set of representative 24h periods is extracted from the full data, and to each of these days a weight is assigned, which can be seen as the number of times this day has to be repeated to rebuild a full yearly data-set (8760 time steps). After the extraction of the representative days, it is important to reconstruct a chronological order, i.e. assigning these days where they are most representative of the original time-series. To these end "the chronological ordering minimises the squared error of the representative data sets with regard to the original data sets" [51].

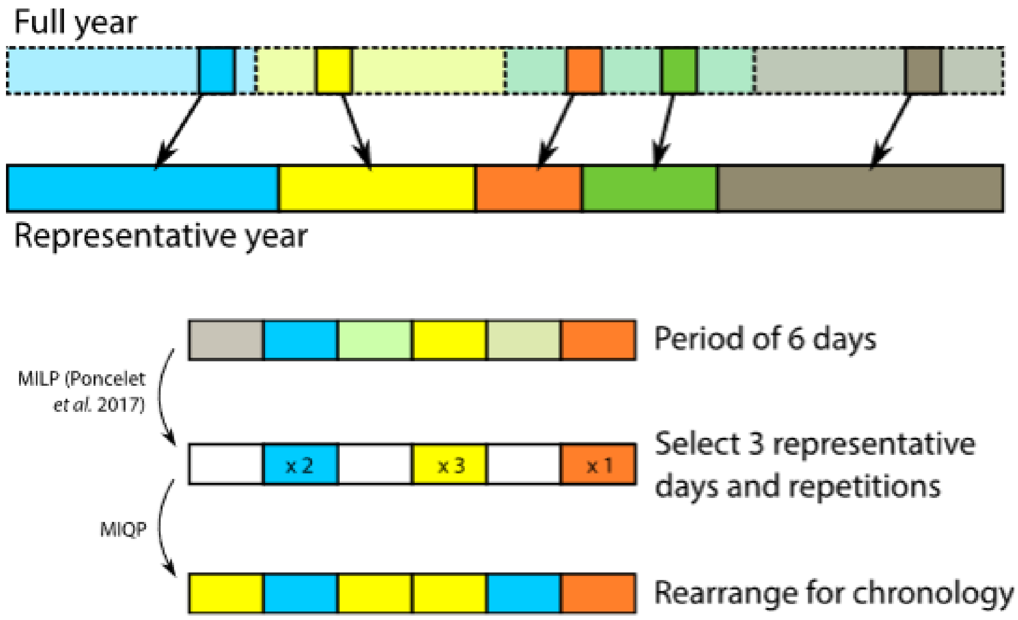


FIGURE 3.1: Example of representative days extraction and chronological order reconstruction [51]

One of the most important shortcomings of this method is that it is very difficult to capture a realistic operation of energy storage, since, by definition, the state of charge evolves chronologically. For this reason, the analysis presented in this thesis will not use clustering but the full time series (8760 time steps).

3.3 Modelling techniques: state of the art

A very large number of energy system models is currently present and cited in literature, with new updates and brand new engines coming out quite frequently. These models can vary in temporal, technical and spatial scope, as well as the goal of their analysis and the solving methods, following the distinctions explained in section 3.1.
Another interesting aspect is that, in the past, most tools used in the energy system were private and were not distributed. However, international research and development organizations have been creating more open source technologies in recent years. More than half of the tools listed by the open energy modeling (openmod) are based on the open-source Python scripting language [52].

The literature review conducted for this thesis included papers covering a broad field of modelling aspects, all addressing a range of specific research subjects. These can range, for instance, from large, macro-economic models with multiple energy sectors to bottom-up, local models.
To select a suitable optimization framework for this thesis, its capabilities regarding the representation of flexibility options have surely been one of the most important points of analysis. Since the topic of system integration is relatively young, not many optimization tools include detailed and powerful descriptions of the elements that characterize such power systems.
The most important flexibility categories that should be included in a tool, according to [53], are *grid representation*, such as grid types, topology and ancillary services, *storage*, which can assume different operational characteristics and time scales (short-term storage, seasonal storage, etc.), and, finally, *supply & demand* technologies and the level of detail of their representation.
Other, more sophisticated, components and properties of energy tools can include *Demand elasticity* (how the demand reacts to changes in prices), *Demand response* (shifting loads when it's more convenient for a healthy and stable operation of the grid) and considering, for instance, also *emissions* in a multi-objective optimization.

Before giving a main overview of the considered frameworks, it can be helpful to provide a short overview of the modeling characteristics that were deemed necessary for this thesis' work:

- Capability to provide operational and decision making results
- Capability to model network constraints
- Capability to model multiple energy networks and flows and interconnections between them
- Capability to model energy storage components
- An 1-hour time resolution

TABLE 3.2: Optimization models under consideration

Model name	Scope	Formulation	Step size	Detail level
PyPSA	P&O	MILP	Hourly	Grey
oemof-solph	P&O	MILP	Hourly	Grey
OsEMOSYS	P	LP	Intra-Annual	Grey
Calliope	P&O	LP	Hourly	Grey
TIMES	P&O	MIP	Houlry	Grey

Although TIMES scored a very high performance result in [52], it was not chosen considering the fact that it's based on the GAMS language. All the other tools are coded in Python, which is by far the current standard in scientific calculations, also thanks to the vast environment of useful packages that it's possible to easily integrate, such as *Pandas* and *NumPY*.
OsEMOSYS appears to be more oriented towards large-scale little-detail models. PyPSA is a very powerful tool that has most of its strength in its electrical-modeling tools and therefore, since the model treated in this thesis is more oriented towards a multi-energy carrier approach, Calliope and oemof-solph have been the most promising ones.
Ultimately, oemof-solph has been the final choice thanks to its large and very active community (the GitHub repository of the project can be found at [54]).

4 Model formulation & formalization

This chapter provides an overview of the characteristics of the model under consideration. The model, which uses generation and demand profiles based on 2050 scenarios, optimizes investments and operations for a whole calendar year (assumed to be 2050). The elements, assumptions, and modeling approaches used to construct this model are described in depth in this chapter.
Section 4.1 starts by describing how the energy model under analysis is represented via oemof; this is then followed in section 4.2 by an overview of the financial assumptions and by a description of how the energy markets (both electricity and hydrogen) have been modeled.

4.1 Representation of coupled energy systems

The model, which is intended as a representation of the energy system of the Drechtsteden area (a detailed description of the case study background will be given in chapter 5), is made up of 5 main components:

- **Buses**: two-ports components where energy flows take place. Each bus must be assigned to a specific energy carrier.
- **Sources**: one-port components from which an energy flow originates.
- **Sinks**: one-port components from which an energy flow is absorbed.
- **Transformers**: conversion devices from one energy carrier to another (fuel cells, electrolysers) or within the same energy carrier (transformers, gas depressurization substations).
- **Lines**: two-ports components used to model an electrical line
- **Storage components**: components where an energy carrier can be stored with specific parameters (such as inflow/outflow efficiency, self-discharge efficiency, etc.).

Each **bus** has a carrier type, so, in this work, electricity, hydrogen and heat buses are modeled. This model divides the Drechtsteden region in 5 different areas, therefore there are 15 buses (one electrical, one hydrogen and one heat for each area).
An additional electrical and hydrogen bus per neighbourhood is needed to model the flow of energy and hydrogen to and from the external market (more of which will be discussed in section 4.2). Therefore, each neighbourhood has an electrical bus at 20 kV and one at 150 kV, together with one hydrogen bus at 8 bar and one at 40 bar, for a total of 25 buses in the whole region.

The **source** components can model two elements. Either connections to the external grid (both electrical and hydrogen) where energy flows are imported in the system, or electrical generators within the region. In particular, since the future scenarios that serve as the starting point for these simulations envision an almost 100% renewable energy system, these generators include only PV panels, wind turbines and biomass-fired generators.

The **sink** components can model two elements as well. Either connections to the external grid (both electrical and hydrogen) where energy flows generated inside the region are sold to the external grid, or local demand (given by three horuly profiles for electrical, hydrogen and heat demand).

Transformers are used to model 4 components of the system:

- Electrical transformers of 90 MVA and 99% efficiency [26]
- Gas substation where hydrogen is depressurized from the national grid (40 bar) to the distribution grid operated by Stedin (8 bar) with a 99% efficiency [26].
- Proton Exchange membrane fuel cells with specifications as in table 2.1. One port input (hydrogen) and two ports output (electricity + heat)
- Proton Exchange membrane electrolysers with specifications as in table 2.1. One port input (electricity) and two ports output (hydrogen + heat)

To avoid over-sizing the hydrogen depressurizing substations, the fuel cells and the electrolysers have been connected to the hydrogen bus at 40 bar (the national grid). In this way, hydrogen bought from the grid to be used in a fuel cell or sold to the grid from the electrolysers does not have to pass through these substations, which therefore handle only the hydrogen demand from the neighbourhoods.
The conversion efficiency of the fuel cells and electrolysers to heat has been determined using HVC's data (as will be explained in more detail in section 5.1.1) and the size of the heat demand for every neighbourhood. Currently, the losses in the district heating network of Dordrecht amount to roughly 23% for a system of 44MW of peak heat demand [55].
For such scale of heat flows, it is possible to linearly approximate the heat

losses of the system with the length of the lines, and the length of the lines with the heat power that they must serve. As an example, a difference in x% of the heat demand will result in a similar x% difference in the length of the network, therefore resulting in x% difference in losses [56] [57].

Lines serve as a simplified representation of electrical connections. Since, how it can be seen is figure 5.3 the electrical lines to be modeled are all at 150 kV, and therefore operated by TenneT and not by Stedin, it is assumed that they will not be the bottleneck and their capacity is assumed to be large enough to satisfy the flows at the transformers. A transmission efficiency of 97% has been assumed for these lines [58].

Finally, **storage** components are used to model batteries and hydrogen storage in the pipelines (the so called *linepack*).
The selected battery investment candidate is a 4-hour Li-Ion battery (i.e. with a capacity 4 times higher than its rated power), as they are expected to be the most widely adopted technology of electrical storage [59]. Furthermore, an in-outflow efficiency of 85% is assumed for this battery asset, according to [60].
Regarding hydrogen storage, only the storage inside pipelines has been considered in this work due to the very high costs of other forms of storage such as compressed, liquefied or chemically bounded.
This type of gas storage is essential for properly balancing supply and demand both in the existing natural-gas infrastructure and in the future hydrogen one. Short-term storage in pipelines, also known as linepack, enables a nearly constant flow of natural gas into the network in spite of greatly varying demand patterns. The fundamental idea behind linepack is to change the pressure while staying within the design tolerances of the pipeline in order to alter the amount of gas that is stored [61].
Following the technical assumptions from [61], it is assumed that the linepack is able to store roughly 0.1 MWh per MW of hydrogen flow.
As a secondary comparative analysis, a simplified form of thermal storage has also been considered. Due to the modeling limitations of oemof, only a short term thermal storage will be included. The selected asset is a water tank storage, an already mature technology with some operational examples already present [41]. The efficiency of these systems can be moderately high, with values as high as 95%. On this work, an efficiency of 85% has been assumed [62]. Taking inspiration from the already present 185MWh/30MW water tank storage in the district heating network of Rotterdam, the capacity/power ratio of this asset has been set to 6 [63].

The following image may help to visualize the energy flows inside the system. For ease of visualization, one must picture the transformers and the electrical lines at the "electricity bus", and the hydrogen substations at the "hydrogen bus". As mentioned earlier, the implementation in oemof actually considers two buses for the electrical and hydrogen sector (one before the transformer/substation and one after it). Furthermore, as just anticipated, a thermal storage will also be considered only as a secondary analysis to compare its effect with the main results. Finally, the buses are intended to represent also the electrical, hydrogen and heat demand.

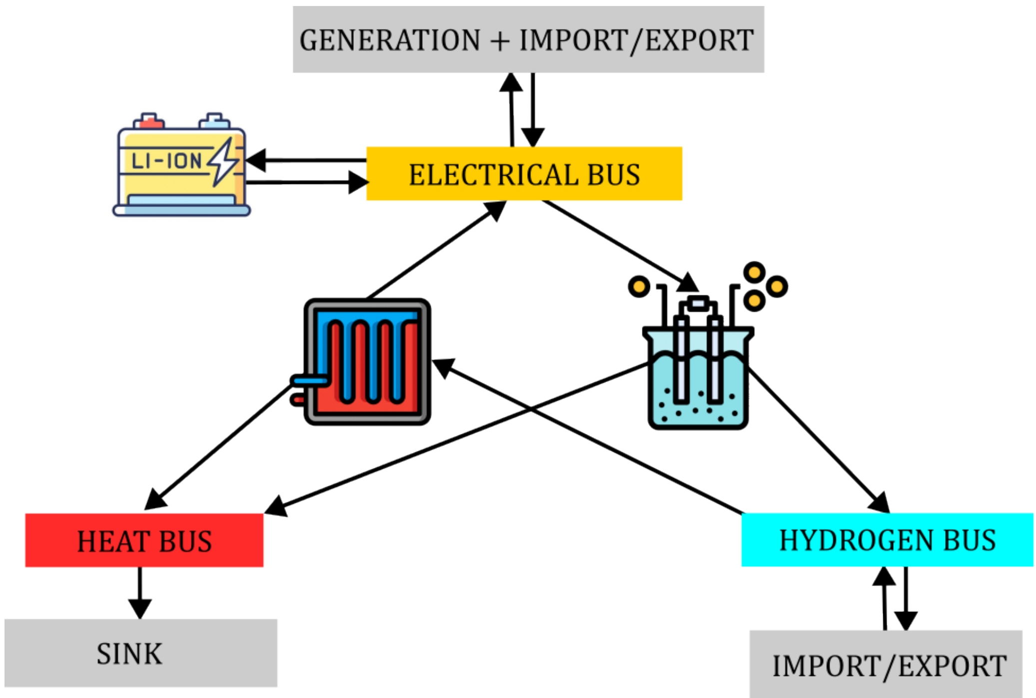


FIGURE 4.1: Schematic overview of the energy system at the neighbourhood level

4.2 Financial & energy market assumptions

4.2.1 Investments and annualised costs

The main goal of this optimization is to provide a quantitative overview of the investments that might be necessary to improve/overhaul the energy system of the region, looking at how it is expected to evolve up to 2050.
Therefore, it is important to consider realistic investments parameters and assumptions for the components that are included in the scope of this model. Namely, this data comprises the CAPEX, lifetime, WACC and OPEX of transformers, substations, fuel cells, electrolysers, Li-Ion batteries and hydrogen substations.

TABLE 4.1: Economic parameter of the considered assets

Technologies	CAPEX	Lifetime	WACC	Ref.
PEM Fuel Cell	900.000€/MW	20	0.07	[64]
PEM Electrolyser	650.000€/MW	20	0.07	[64]
Li-Ion Battery	110.000€/MWh	12	0.07	[59]
Water tank	10.000 €/MWh	15	0.07	[41]
Transformer (90MVA)	1.700.000€	30	0.04	[26]
Hydrogen substation (68MW)	3.500.000€	100	0.04	[26]

The WACC values were re-elaborated using [65] as a source. The price level of the Li-Ion battery indicated in the table is the "optimistic" one; another "conservative" price level of 180.000€/MWh has also been considered.
The model receives the annualised cost for each of these assets as input, which then influence the optimization outcome in terms of the capacity of the investments that are chosen by the solver. In this way it is possible to make a comparison between the systems costs and the money flows (costs and earnings) arising from the interaction with the external grid.

oemof has a built-in package called "economics" that has been used to calculate the annualised costs following the equation:

$$C = capex \cdot (wacc \cdot (1 + wacc)^{lifetime})/((1 + wacc)^{lifetime} - 1)$$

4.2.2 Energy markets model

The model is developed for a small region of the distribution network that, therefore, must also feature connections with an external grid.
This external grid, as briefly mentioned in section 4.1, is modelled as a "sink" when the region is in surplus and energy (electricity or hydrogen) can be sold, or as a "source" when the region is in deficit and energy must be purchased from the outside.
In order for this system to behave in a realistic way, the variable costs associated with an energy flow to the external sink or from the external source must mimic the behaviour of an energy market. Therefore, two simple market models have been developed to obtain a hourly time series of prices for electricity and hydrogen.

ELECTRICITY MARKET

At present, a large and growing amount of different electricity markets is operational. Starting from the most famous *wholesale market*, there is also the *intraday market* used to modify the bids of the wholesale market on the day of delivery, the *FCR market* or frequency control reserve market, used to balance the instantaneous frequency deviations in the grid, and the *FRR market* or frequency restoration reserve, used when the assets operating in the FCR market are not enough to maintain the grid's frequency in the desirable operating range.
Since modeling the vast complexity of all these markets was outside the scope of this thesis, attention has been given only to the *wholesale market*, and a simple model taking data from Stedin as input has been developed.

This market is based on a *market clearing algorithm* done with linear optimization, in which the *social welfare* of the system is maximised (i.e. the sum of consumers and generators surpluses).
This models contains only the equality constraint "total accepted demand = total accepted generation", therefore the market-clearing price is the Lagrange multiplier of the market-clearing constraint. The time series of these Lagrange multipliers is what makes the electricity prices.
On the supply side, 5 price levels have been modeled, each depending on their respective LCOE:

- PV: 20 €/MWh [66]
- Onshore wind: 42 €/MWh [66][67]
- Offshore wind: 55 €/MWh [66][67]
- Cross-border price: 75 €/MWh [68]
- Biomass peak generators: 110 €/MWh [69]

On the demand side, the vast majority of it has been considered inflexible due to the fact that the Stedin's energy model where it has been taken, as described in chapter 5, is a perfectly balanced model, therefore changing by a great margin the amount of electricity actually delivered would have not been a viable option.
Instead, only the category of demand called "Other demand" (around 8% of the total demand) has been set at a price level of 55 €/MWh (i.e. to be satisfied only with renewables since that's the price of the marginal renewable generator, offshore wind).
A snapshot of the market can be observed in the following figure, in which A1 is the earlier called "producer surplus" and A2 is the "consumer surplus"

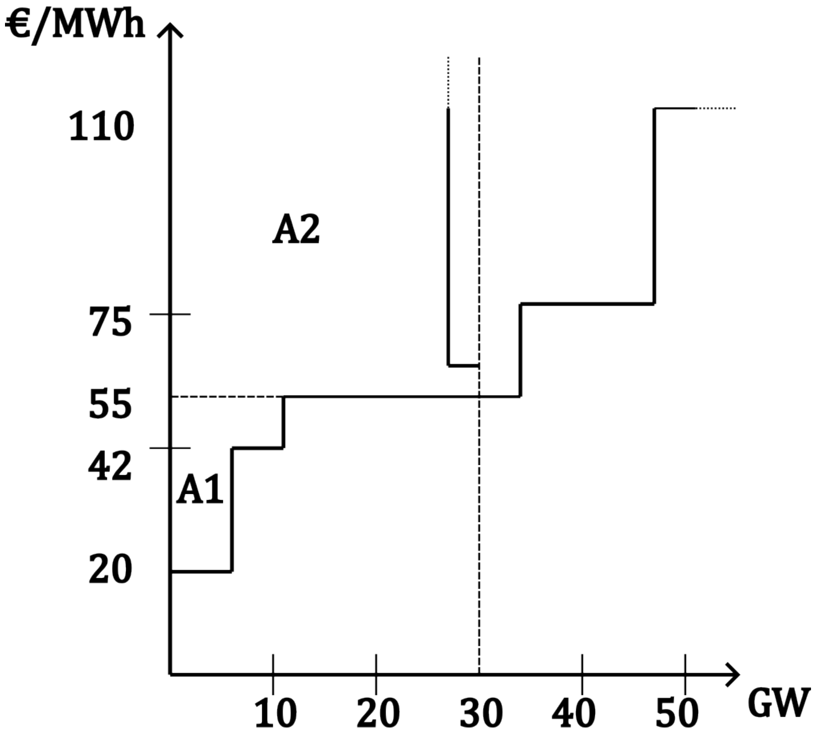


FIGURE 4.2: Electricity market snapshot at 12:00 of the 1st of January: offshore wind generators are the marginal ones and the clearing price is 55€/MWh

As it can be observed in figures 4.5 and 4.6, a summer seasonality pattern is present due to higher PV generation and lower demand, which brings down the price. It can also be observed how the higher share of renewables present in the regional scenario brings down the average price of the whole year.

In order to validate the presented electricity market, data from 2019 has been used as input to see if the model's output resembled the actual prices that occurred in that year.
Of course, the sources and the price levels are different than the model for 2050, namely:

- Renewables: 0 €/MWh [70]
- Gas: 20 €/MWh [71]
- Nuclear: 29 €/MWh [72]
- Coal: 34 €/MWh [72]
- Import: 42 €/MWh [73]
- CCGT: 75 €/MWh [72]

The generation and load data for the Netherlands has been taken from [73] and used as input for the electricity market model, resulting in the plot of figure 4.3

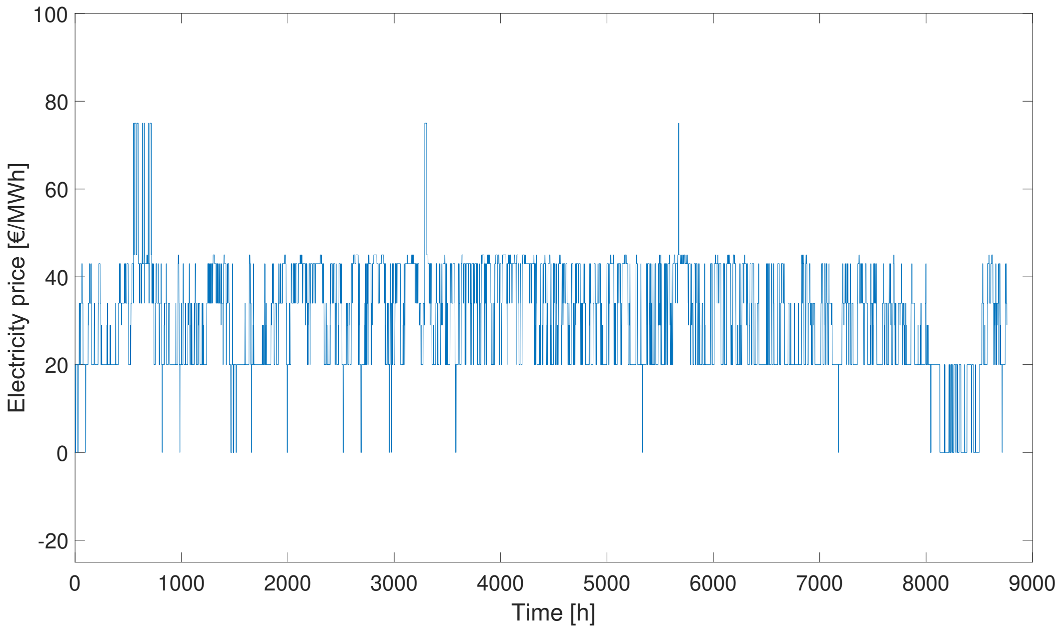


FIGURE 4.3: Electricity market model for 2019

It is now possible to compare the output of the model with the actual prices, presented in figure 4.4

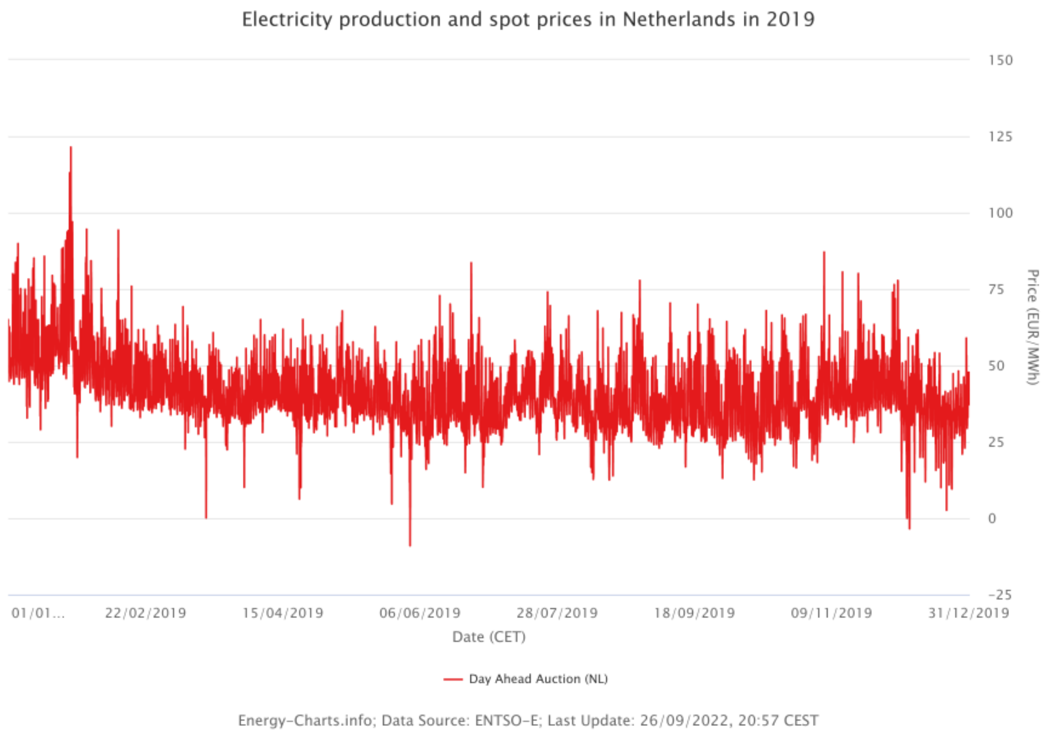


FIGURE 4.4: Real electricity prices for 2019 [73]

Comparing the two plots, four main similarities can be observed:

- Similar average price for the year
- Price peaks towards the end of January
- Stability in the second half of the year
- Low prices towards the end of the year (likely driven by high winter winds)

The presented model therefore appears to be quite accurate and validated.

HYDROGEN MARKET

At the present time no wholesale hydrogen market has ever been tested, and no plans to do that are likely envisioned in the foreseeable future. However, this might change in the coming decades if the importance of hydrogen in the energy mix will continue to increase.
In the model presented in this thesis hydrogen plays a fundamental role, therefore the assumption is that a wholesale market similar to that of electricity will arise to support the trade of this commodity.
The design of this market stands on three main assumptions:

- **Electricity-Hydrogen market link:** given the fact that, in the scenarios considered in this work, almost all the hydrogen is produced via electrolysis (and therefore via electricity), another important assumption is to link the hydrogen market with the electricity market. In fact, if one is to produce hydrogen, first it has to purchase electricity from the grid (except for standalone electricity generation - hydrogen production units which have not been considered in this thesis).

- **LCOH correction:** since the assets used to produce hydrogen have different annual costs, and since the conversion pathway from electricity to hydrogen presents some losses, it is reasonable to add a corrective factor to the electricity price to account for these differences. Re-elaborating a definition of LCOH from [13], the corrective factor is calculated as:

  $$k = \frac{CAPEX_{electrolyser} \cdot lifetime_{res}}{lifetime_{electrolyser} \cdot CAPEX_{res} \cdot \eta_{electrolyser}} = \frac{650 \cdot 30}{20 \cdot 850 \cdot 0.97}$$

  Where the lifetime and CAPEX data has been taken from [66][74]. Regarding the CAPEX and lifetime of renewable sources, only solar and wind energy have been considered, and an average has been made considering the share of wind and solar in the Netherlands [3]. The equation is brought in this simplified form also because of the fact that the capacity factor of renewable sources and of electrolysers are often comparable, and therefore in the equation it is assumed that the lifetime output from the two sources is the same [75].

- **Hydrogen request index:** as it will be explained in more detail in chapter 5, a large part of the input data for this model comes from a study done by the grid operators of the Netherlands which, among other things, contains yearly time series for the predicted generation and demand for 2050 for electricity and hydrogen.
  The third assumption is therefore to link the hydrogen price with a factor given by the instantaneous (per hour) difference between the hydrogen demand (H_d) and the electrical generation available after having satisfied the electrical demand (E_a). High values of this $H_d - E_a$ will increase the price as there is a lot of hydrogen demand and little (or even negative) electricity surplus, while low values will decrease the price since there is not much demand and a lot of excess generation that can be used for electrolysis.

- **Supply slope:** the fourth and final assumption needed to finish the model is to link the average slope of the supply curve of the electricity market to the equation determining the hydrogen price. Again, this was deemed the safest assumption possible given the absence of any form of hydrogen market for validation and given the deep interconnection between the hydrogen and electricity markets.
  The hydrogen supply curve at any hour is of the form $y = ax + b$ where x is the $H_d - E_a$ variable, "b" is the instantaneous electricity price corrected with the LCOH constant, kE_p, and "a" is the angular coefficient of the supply curve which, as said, is put equal to an average value taken from literature for the electricity market of 1.1 (€/MWh)/GW [76][77].
  With this formulation, when the demand equals the leftover electrical availability the hydrogen price is simply the electricity price corrected with the LCOH factor, for different values of $H_d - E_a$ the electricity price might then either be increased or decreased to obtain the hydrogen price. The full formulation is therefore:

$$H_p = kE_p + (1.1 \cdot (H_d - E_a))$$

As it can be observed in figures 4.5 and 4.6, the hydrogen market presents, as expected, average values higher than the electricity market and, again as expected, a seasonal pattern similar to that of the electricity market. The international prices are on average higher than the regional ones, but it can be interesting to note higher peaks on the regional market: these are most probably due to the higher dependency on renewables of this scenario, therefore, on those points, the electrical shortage has reached more intense levels and, as a consequence, the hydrogen price increases by a great margin.

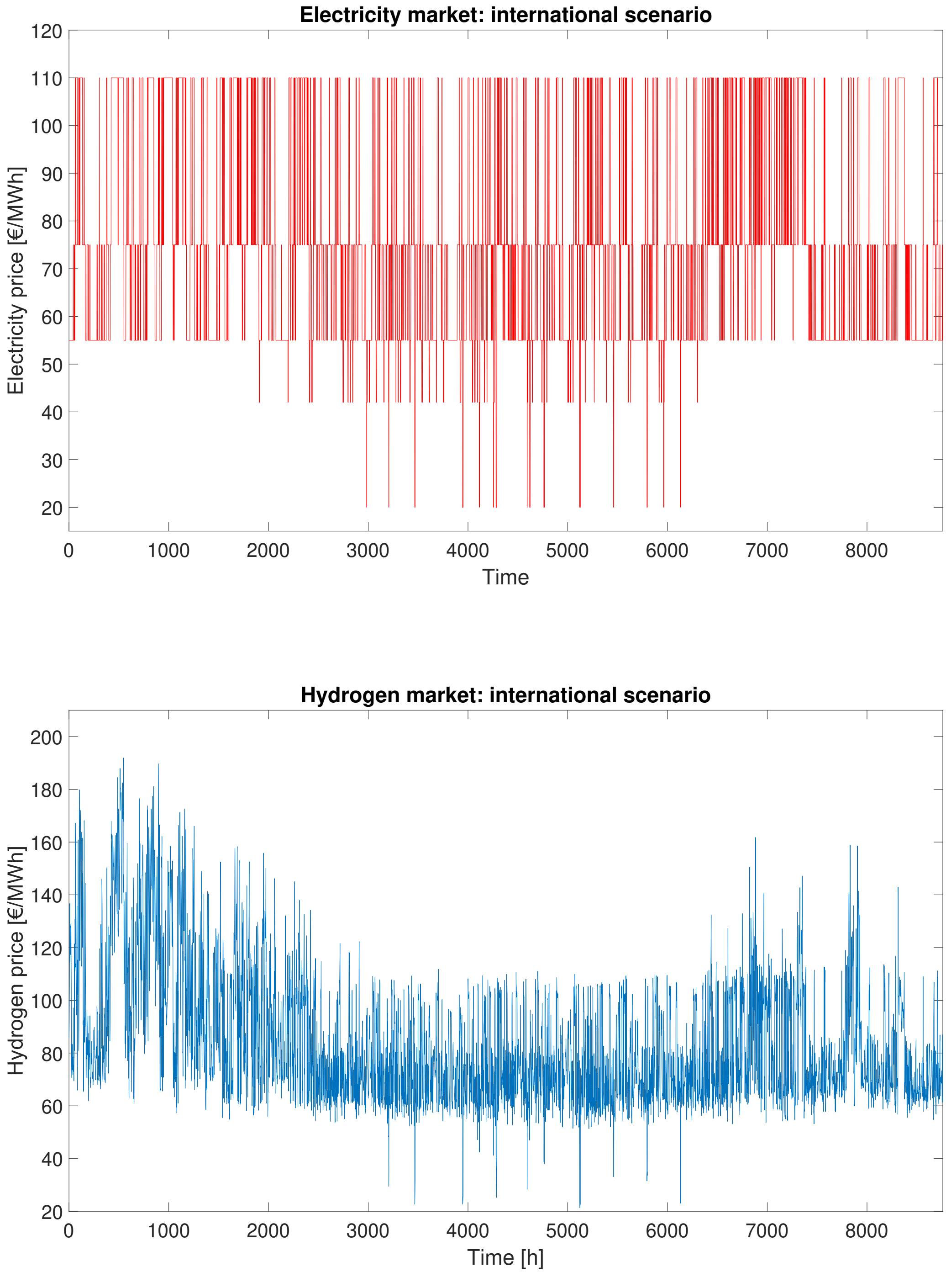


FIGURE 4.5: Energy markets for the international scenario

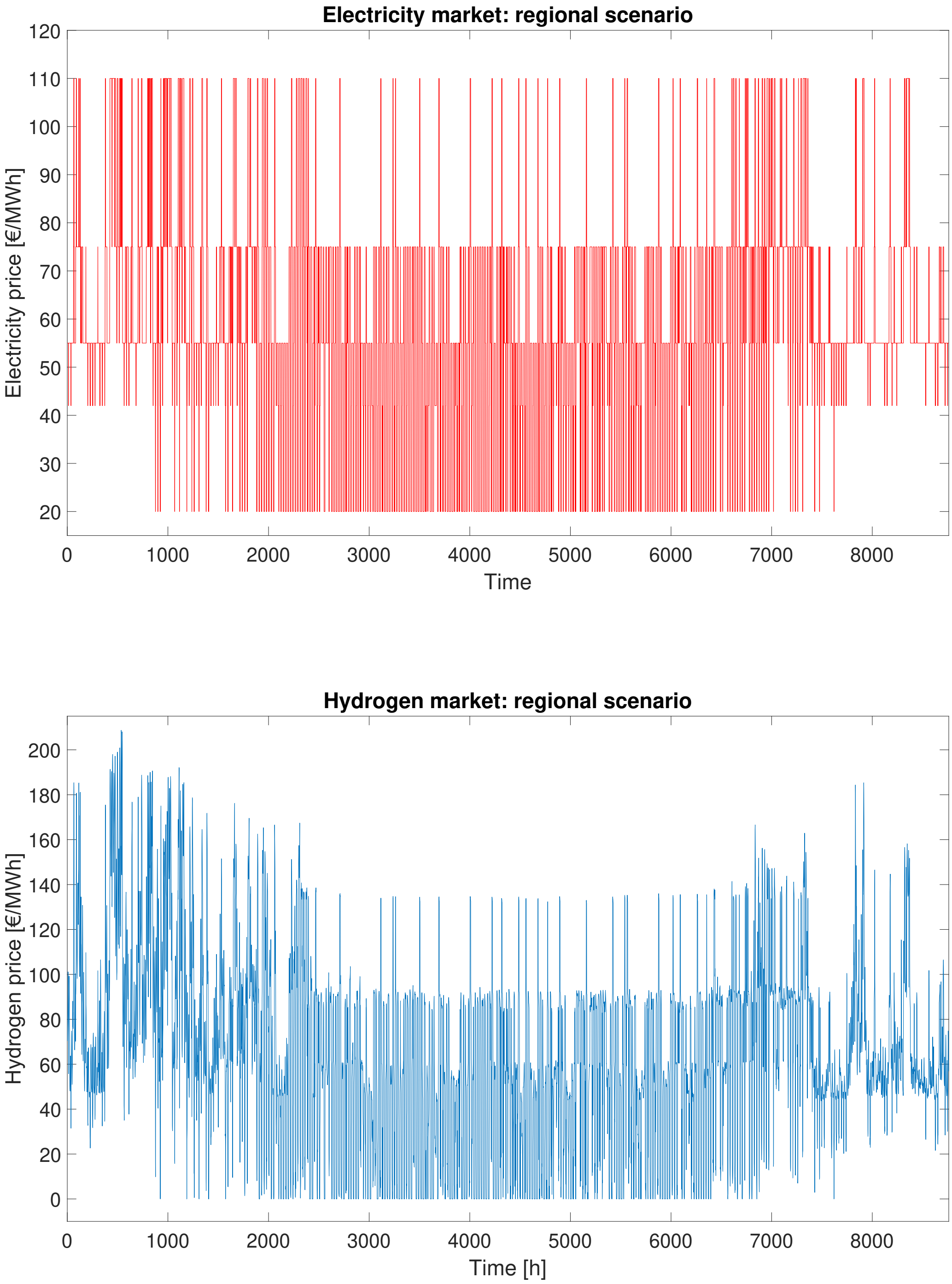


FIGURE 4.6: Energy markets for the regional scenario

4.3 Objective function, constraints and solver

The energy system is converted into an optimization problem in Pyomo, an open-source optimisation modeling language for Python, using oemof. As any standard optimization problem, the Pyomo package then uses equality and inequality expressions to create objectives and constraints.

The objective function of the optimization problem is the sum of every cost variable of the system, both the one-time investments costs (such as the ones needed to build transformers, fuel cells, etc.) and the operational costs (i.e. the exchange with the external grid). The goal of the optimization is to minimize such cost function, which can be expressed as follows:

$$C(\mathbf{P}, \mathbf{E}, \mathbf{T}) = \sum_c \sum_n c_c \cdot P_{c,n} + \sum_n c_b \cdot E_n + \sum_v \sum_n \sum_t p_{v,t} \cdot T_{v,n,t}$$

Where:

- $c = \{1, 2, 3, 4\}$: index for the specific component (transformer, hydrogen substation, electrolyser, fuel cell)
- $n = \{1, 2, 3, 4, 5\}$: index for the specific bus. Regardless of bus type, every component can be invested in at every bus (therefore, 5 indexes).
- P_n: invested power rating [MW] of the specific component c at bus n
- c_b: cost per MWh of the battery storage candidate
- E_n: invested capacity [MWh] of the battery at bus n
- v: energy vector traded on the markets (electricity or hydrogen)
- $t = \{1, ..., 8760\}$: time step of the simulation
- $p_{v,t}$: market price [€/MWh] of energy vector v at time step t
- $T_{v,n,t}$: traded energy [MWh] of energy vector v at bus n at time step t
- **P**,**E**, **T**: are the vectors of all the variables of the cost function

Along with the objective function the problem comprises also a number of constraints specific to every component of the system:

- On every bus a *power balance* constraint is enforced between all its inputs (i) and outputs (o):

$$\sum P_i(t) = \sum P_o(t) \ \forall t, i, o$$

- Flow objects related to local generation units and local electricity, hydrogen and heat demand have a pre-determined value at every time step coming from the input files. Therefore their only constraint is:

$$P(t) = f_{fix}$$

Where $P(t)$ is the instantaneous power and f_{fix} is its (fixed) input value.

- Flow objects related to invested assets (transformers, electrolysers, fuel cells and hydrogen substations) do not have a fixed input value since their flow variable is determined during the optimization:

$$f_{min} \cdot P_{nom} \leq P(t) \leq f_{max} \cdot P_{nom}$$

Where P_{nom} is the nominal capacity of the component coming from the result of the investment optimization and f_{min} and f_{max} are the (normalized) minimum and maximum values that a specific flow will take during the optimization (again, these are results of the optimization and not inputs).
The effective flow is then calculated including the efficiency conversion:

$$P_{eff}(t) = \eta P(t)$$

Where to every component a specific η value is assigned (as discussed in previous chapters).

- Storage components feature another set of constraints. The energy content of the storage component at every time step is given by:

$$E(t) = E(t-1) \cdot (1-\beta(t)) - \gamma(t) \cdot (E_{exist} + E_{invest}) - \delta(t) - \frac{P_o(t)}{\eta_o(t)} + P_i(t) \cdot \eta_i$$

Where $E(t-1)$ is the energy content at the previous timestep, $\beta(t)$ is the fraction of lost energy as share of $E(t)$, $\gamma(t)$ is the fixed loss of energy relative to $E_{invest} + E_{exist}$, $\delta(t)$ is the absolute fixed loss of energy per time unit, η_i is the conversion factor when storing energy and η_o is the conversion factor when taking stored energy.

Furthermore, an initial storage level constraint is given:

$$E(-1) = E_{invest} + E_{exist} \cdot c(-1)$$

Where in our case $c(-1) = 0.5$
Finally, to connect the invest variables of the storage and the input/output flow:

$$P_{i,invest} + P_{i,exist} = (E_{invest} + E_{exist}) \cdot r_{cap}$$

Where r_{cap} is the relation of storage capacity and nominal flow. For the 4h battery modeled in this work, this value is therefore 1/4.

The Pyomo optimisation problem can be solved using a variety of solvers, including open-source models. In this work, the commercial solver Gurobi is utilized because of its faster solving times. This solver can be used freely with an academic license [78].
Despite the mixed-integer capabilities of the oemof package, this model is developed as a linear optimization problem. In this way, transformers can

assume any rating value (in MVA), which is not realistic since there is a strong preference in standardizing transformers sizes (as can be seen with the 90MVA transformers in figure 5.3). However, in the cost calculations it is assumed that only multiples of 90MVA transformers will be installed: therefore, the installed capacity is the next multiple of 90 able to satisfy the calculated flow. This trade-off in accuracy comes with a great advantage in computation time. In fact, this linear model can be solved in its entirety (8760 time steps) in about 7 minutes.

In this way, storage components can be included in a more realistic way without compromising the input time series, since the extraction of so called "representative days" (as explained in section 3.2) is no longer necessary and the temporal continuity of the optimization is guaranteed.

5 Case study: Drechtsteden region

This chapters aims to provide an overview of the region under consideration for this research and the data inputs used for the model. The Drechtsteden region is introduced in section 5.1, along with the features of the existing network, which serves as the starting point for expansion planning. In addition, the existing district heating network operated by HVC is introduced, along with the current plans for its expansion. The various scenarios for future local generation and demand profiles are described in section 5.2. Following that, in section 5.3, a description of the input data for the model is presented.

5.1 Existing network & future scenarios

The area under consideration is the one served by the 150/50 kV substation located in Sterrenburg (a neighbourhood of Dordrecht, south of Rotterdam). This area has currently around 180.000 inhabitants and an area of about 400 square kilometers.

As we can see from figure 5.1 this area includes a large part the city of Dordrecht in the green "Sterrenburg district". This area is the one in which most of the demand will be located.
Dordtse Kil is still an urbanized area in the outskirts of Dordrecht while the remaining three, Oud Beijerland, Dordtse Kil and Klaaswaal are mostly areas scattered will little villages and a lot of farmland.
In particular the large area of Klasswaal (in yellow), serves as the region's "power station" since this is the area in which the highest share of local generation is located. Thanks to the vast "open-air" environment given by the Maas river delta located just south of Klaaswaal, considerable onshore wind potential is expected to be installed.

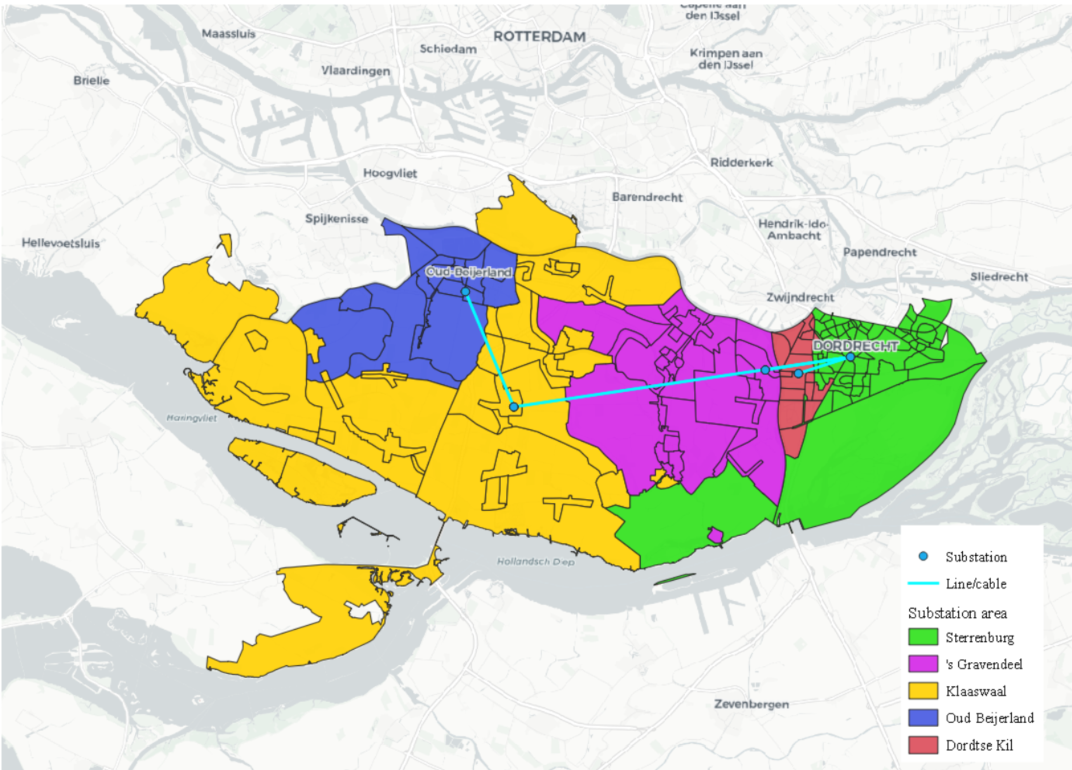


FIGURE 5.1: Areas served by the Sterrenburg substation

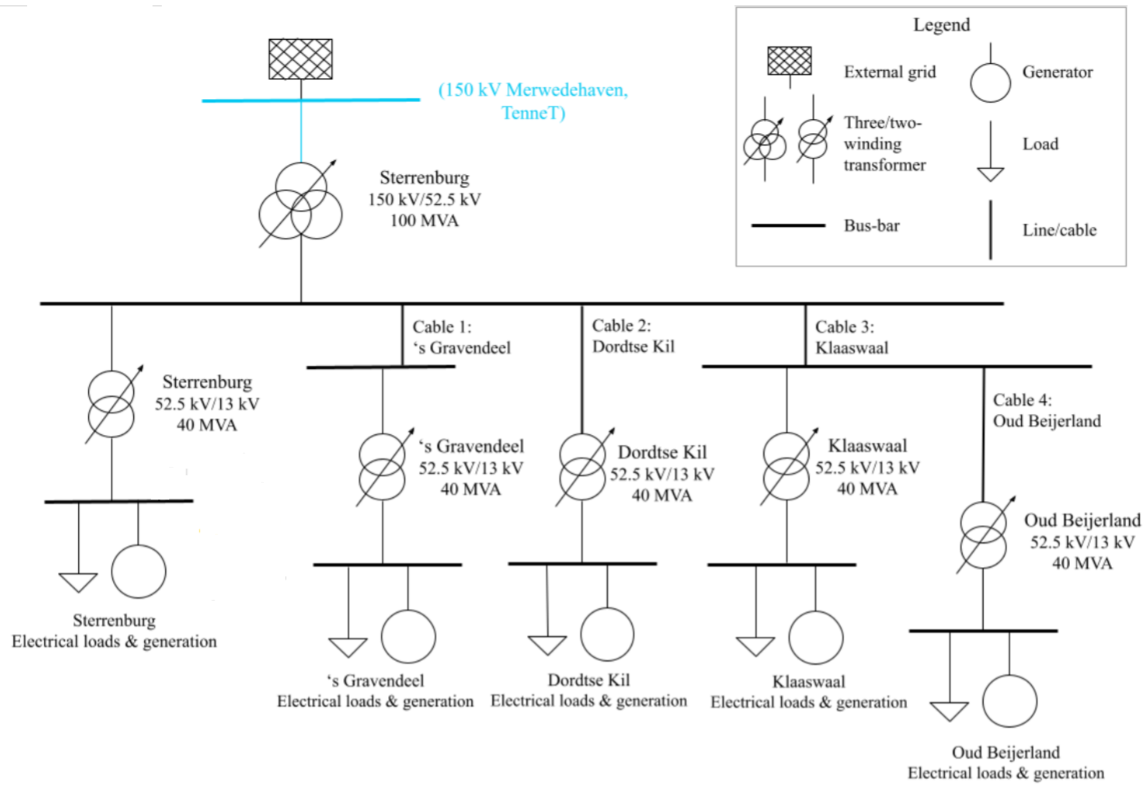


FIGURE 5.2: Electrical diagram of the present infrastructure [26]

Five substations at 52.5/13 kV and one at 150/52.5 kV make up the electrical network in this area. The operator of the national transmission system, TenneT, is responsible for maintaining the infrastructure at voltages of 150 kV and higher. The substations are situated at Sterrenburg, Oud-Beijerland, Gravendeel, Klaaswaal, and Dordtse Kil. The neighborhoods of figure 5.2 are highlighted in different colors depending on the substation that serves them. These places each have a 52.5/13 kV substation, as well as a 150/52.5 kV facility in Sterrenburg. Sterrenburg is the most inhabited area of the region and serves also the city of Dordrecht. As mentioned, the highest generation is found in the neighbourhood of Klaaswaal, which is particularly suitable for onshore wind installations.
Within Stedin, a new configuration of this network has been envisioned and sketched according to the expected flows in 2050. As it can be observed in figure 5.3, two 150 kV connections to the TenneT network are envisioned instead of the single one at the Sterrenburg substation. This is due to the large renewable generation expected in the Klaaswaal neighbourhood. Furthermore, the 52.5/13 kV configuration is substituted with a 150/21 kV one, in which all substations are therefore connected to the 150 kV national grid. Finally it can be observed that the network is decoupled in two sub-networks, eliminating the need for a considerably long connection between Klaaswaal and Sterrenburg [26].

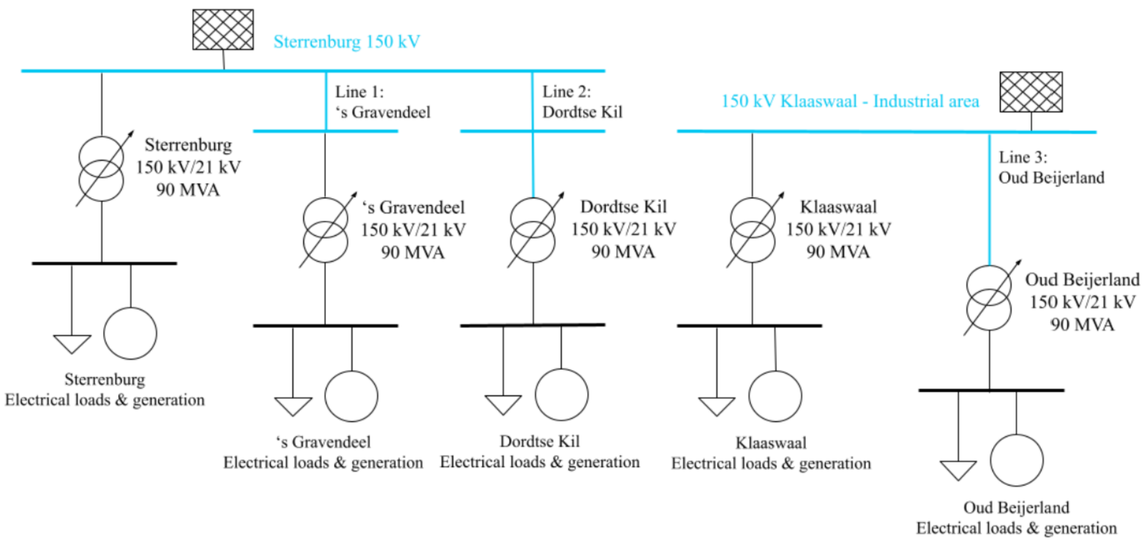


FIGURE 5.3: Electrical diagram of the future infrastructure [26]

As anticipated, the gas network is considered to be completely repurposed for hydrogen. Therefore, the capacities of the natural gas connections of today are corrected with a factor of 1.25 [61] to account for the lower volumetric energy density of hydrogen.

5.1.1 HVC district heating network in Dordrecht

Currently, the city of Dordrecht already has a district heating network which is serving around 7400 (housing equivalent) costumers. The main source of heat generation comes from the waste treatment plant.
This network is rapidly expanding, and the company is actively looking to substitute the current heat source from waste with alternatives (often decentralized). In fact, HVC expects the amount of heat obtainable from waste treatment to decrease in the future, due to higher recycling shares leading to reduced residual waste volumes.
At the moment, the company is exploring three alternatives sources of heat, a geothermal well near Sliedrecht with a potential of roughly 20MW, several water heat pumps drawing water from the Oude Maas, and, finally, a number of distributed gas-fired heat generators.
The geothermal installation is forecast to have a very high COP of 20, and, thanks to its 3.5km depth, it is expected to deliver water at around 90°C constantly throughout the year. Higher COP is also the reason for preferring heat pumps upgrading the river water to around 70°C, with an interesting foreseen potential for seasonal hot water storage. Finally, the gas-fired generators are used mainly to cover peaks during cold winter days (roughly 9% of demand) in order to also avoid over-sizing of the central Baanhoekweg heat generation facility [55].

The company is expecting, as also confirmed by their latest figures, that the share of small scale (residential users) will increase in the future as the grid becomes more and more meshed and extended. Currently, new expansions are accepted only after having agreed for a sufficient pool of demand, which is usually initially arranged with few decision makers that manage large heat connections, such as housing corporations or high-consuming sites such as hospital, schools, etc. . Furthermore, in order to receive the subsidy for a connection with the heat network, any existing methane connection must be removed. This might also require modifications to the buildings, as usually the temperature provided by the DH can be lower than the output from a methane boiler. Higher insulation, larger heat radiators and, possibly, updates in the electrical connection to allow for more electrical appliances (i.e. induction stoves in place of gas stoves), are all aspects which HVC considers crucial for the expansions of the network [55]. This is in complete accordance with what has been found and discussed in subsection 2.4.2.

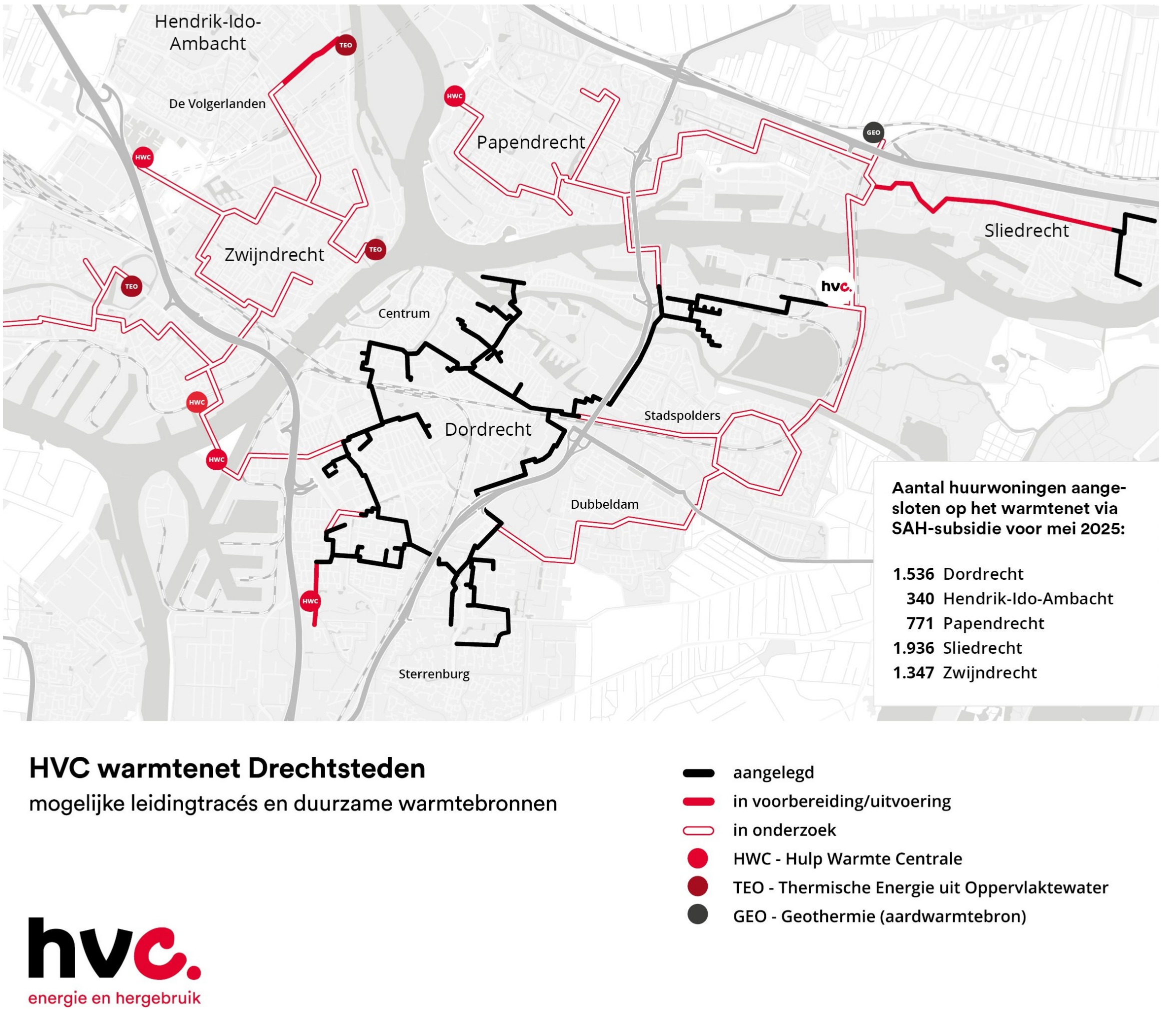


FIGURE 5.4: HVC current heat network and planning map in the Drechtsteden area [79]

5.2 Integral Infrastructure Survey 2050

The main source for the data used in this thesis comes from the *Integrale Infrastructuurverkenning 2030-2050* report written by the Dutch DSOs, the Dutch TSO and the gas grid operator. In this report, experts from each of the many companies involved helped in creating a detailed overview of the trajectories that the Netherlands could take to become climate neutral by 2050. The main aim of this study is to stimulate all the involved stakeholders to accelerate the efforts towards a climate neutrality, also in order to facilitate a smart development of the grids in order to avoid bottlenecks, and make even more evident which investments might be considered "no-regret" ones to be undertaken immediately [3].
To provide an extensive overview of the different futures that might unfold all the way to 2050, 4 scenarios have been developed, with each of them wanting to represent specific economic, societal and policy environments.
Each of these four scenarios can be briefly described as follows:

- **Regional Scenario:** in this scenario, the principle of self-sufficiency guides also the investments in the energy sector. Imports and exports are kept to a minimum and great importance is given to local generation, chiefly from PV and wind. Total demand is the lowest among the scenarios, especially thanks to a strong avversion for energy intensive industries.

- **National Scenario:** in this scenario each country has a more interconnected role in the functioning of the whole European network but cross-border volumes are still kept to a minimum. Project of great scale on a national level may be present.

- **European Scenario:** in this scenario, more energy trade takes place, and the European grid works in a much more interconnected way, both from a physical and also from a policy point of view.

- **International Scenario:** in this last scenario we have the highest degree of interconnection not only with other European country but on a global scale. Large flows of energy allow for an higher demand and energy intensive industries. In this scenario, the importance of hydrogen as an energy carrier is the strongest, especially in the industrial sector.

For each of these scenarios, a large amount of hourly profiles (with yearly span) has been generated to serve as a base for the report.
A division has been made per energy carrier: electricity, methane and hydrogen. For each of these carriers a further division is a number of demand and generation sectors has been done, and for each of them it's possible to have a yearly time-series both on a national scale and also in total percentage terms for each of the neighbourhoods of the Netherlands.
Some examples of electrical demand are *"Agriculture demand"*, *"Household demand"*, *"Metal industry demand"*, *"Transport demand"*, *etc...*, while generation includes *"Wind offshore"*, *"Wind onshore"*, *"PV fields"*, *"Household PV"*, *etc....*
Similar divisions in demand can be found also for the hydrogen and methane datasets.
It should be stressed that in this work these different types of demand and supply are not treated differently since the objective is get a picture of the overall functioning of the energy system. Some parts of the demand data have been treated differently to obtain a regionalization of the heat demand (as will be explained in more detail in the following section).
These scenarios also include some description of flexibility assets and their operation throughout the year, but this data is not used in this work since the aim is to obtain it as output of the optimization.
In this work, the Regional and International scenarios will be taken under consideration, since these represent the two extreme situations in which the infrastructure change might be substantial.

5.3 Input data for the model

Most of the input data from the model comes, as introduced in the previous section, from the II3050 study. It can be divided in four categories as follows:

- Electrical demand [MWh]
- Hydrogen demand [MWh]
- District heating demand [MWh]
- Local generation [MWh]

Electrical, hydrogen and generation were already previously regionalized for the Drechtsteden network. The regionalized district heating demand has instead been constructed starting from the national dataset. First, the difference between the national demand in the electricity, hydrogen and methane sectors related to heating purposes (ref. section 5.2), with the forecasted national district heating demand has been taken. Secondly, this data has been scaled according to the local demand of the 5 neighbourhoods to obtain a realistic yearly profile of heat demand to be satisfied with district heating.

Each of the four categories are further divided in five subsets, one for each of the five neighbourhoods. Therefore, the input data consists of 20 time-series with 8760 elements each (i.e. a full year with a hourly resolution).
Each of the 20 time-series is "connected" to its specific bus (ref. figure 4.1) with the exception of the 5 electrical buses, since these connect both the electrical demand and the local generation.

As it can be seen in figure 5.5, the demand in the international scenario is about 50% higher than in the regional scenario. Furthermore, the demand of the Drechtsteden region shows a seasonality both in the international and regional scenarios, with less demand during the summer months. Electricity is the main energy carrier in both scenarios but, while hydrogen plays an important role in the international, the regional makes less use of it, putting more emphasis on the district heating capacity.

Coming to the generation data (figure 5.6), it can be observed how, in the regional scenario, the production of local electricity is far higher compared to the international one. The typical seasonality of the outputs of wind (higher in winter) and solar (higher in summer) is also evident.

Figure 5.7 shows how the neighbourhood of Sterrenburg (in Dordrecht) has by far the highest demand, while Klaaswaal has the highest local generation thanks to its low population density and large area.

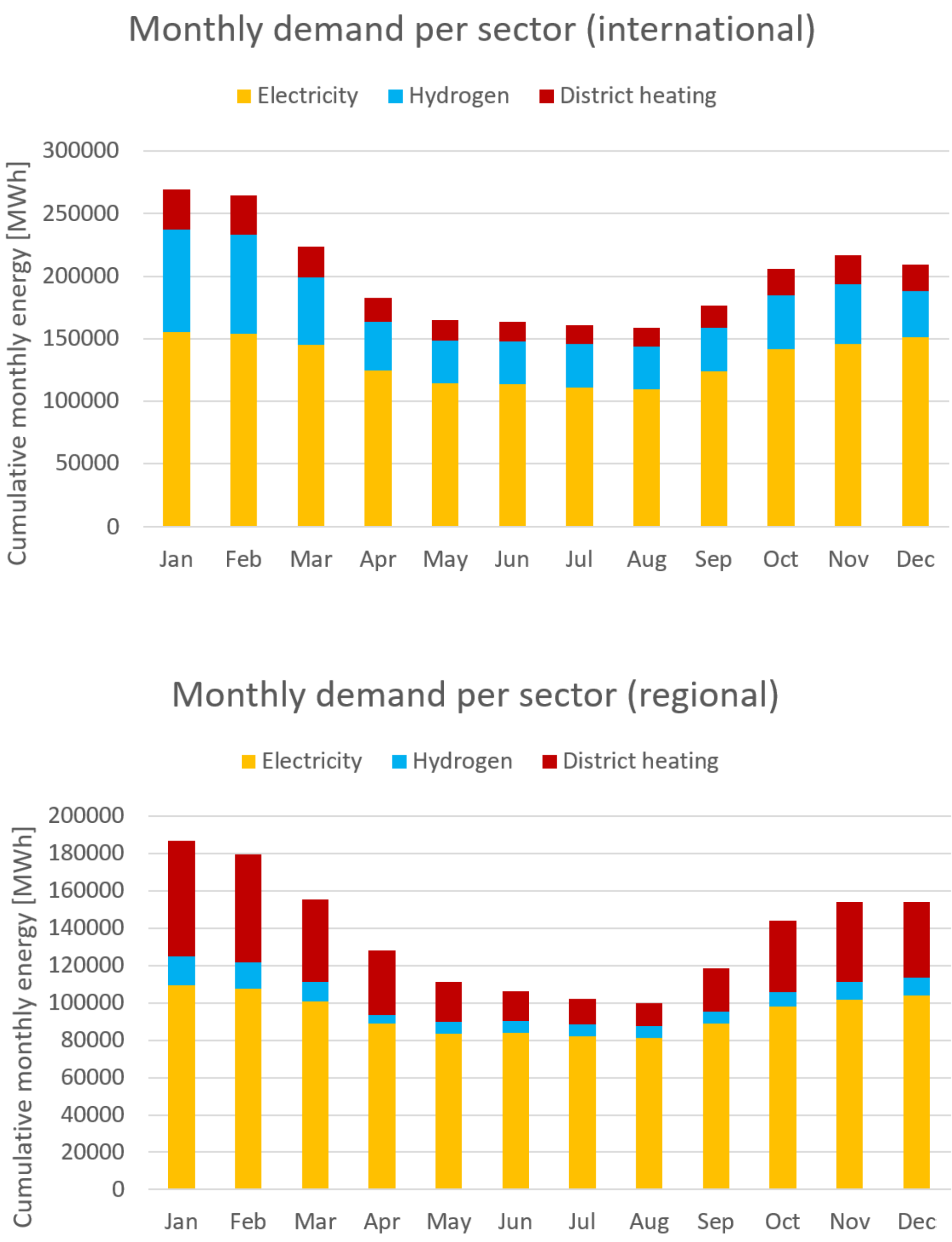
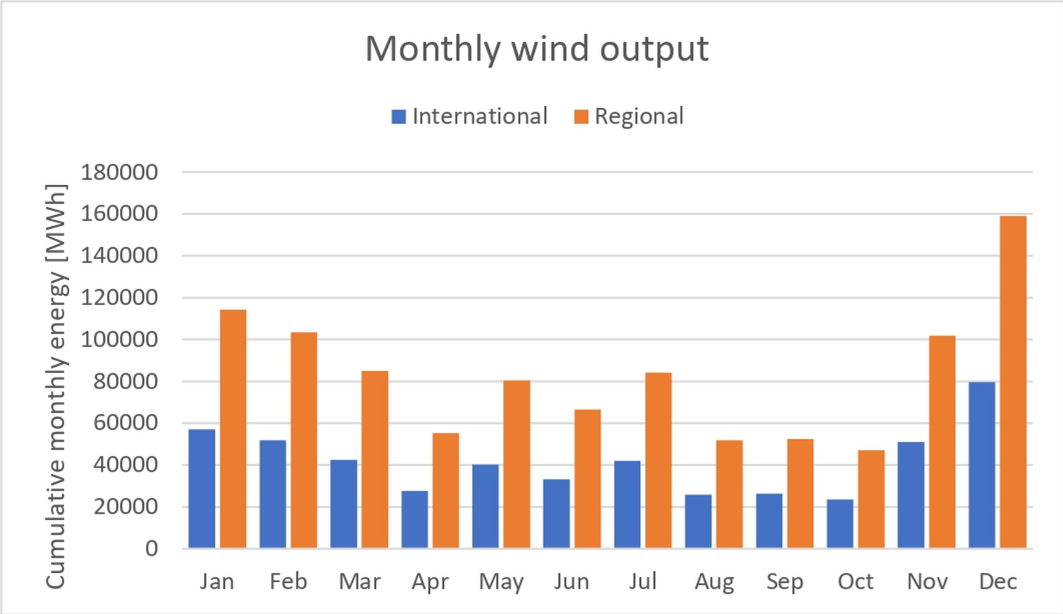


FIGURE 5.5: Demand in the Drechtsteden network



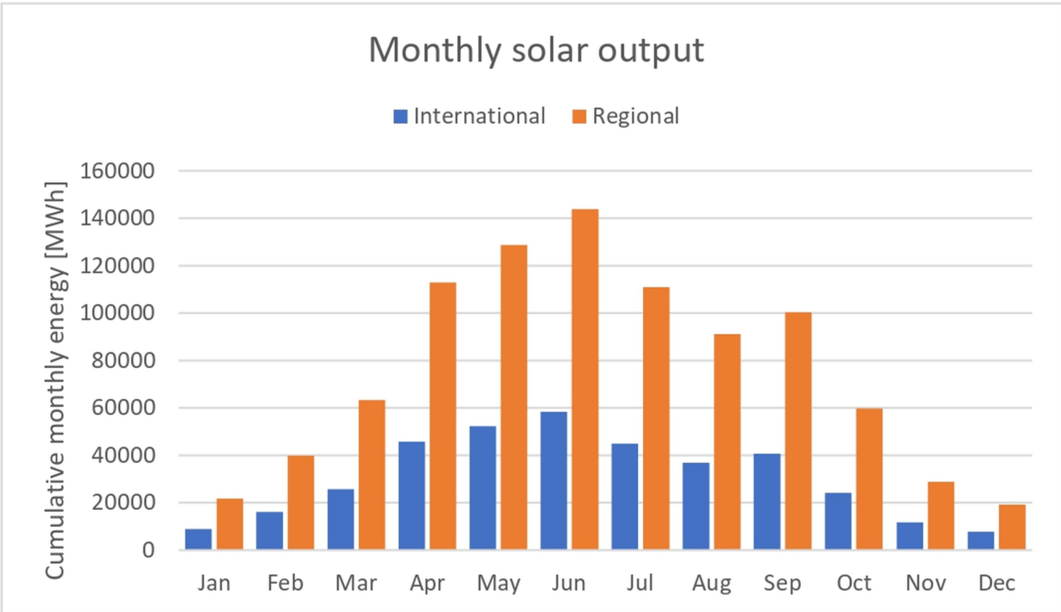


FIGURE 5.6: Generation in the Drechtsteden network

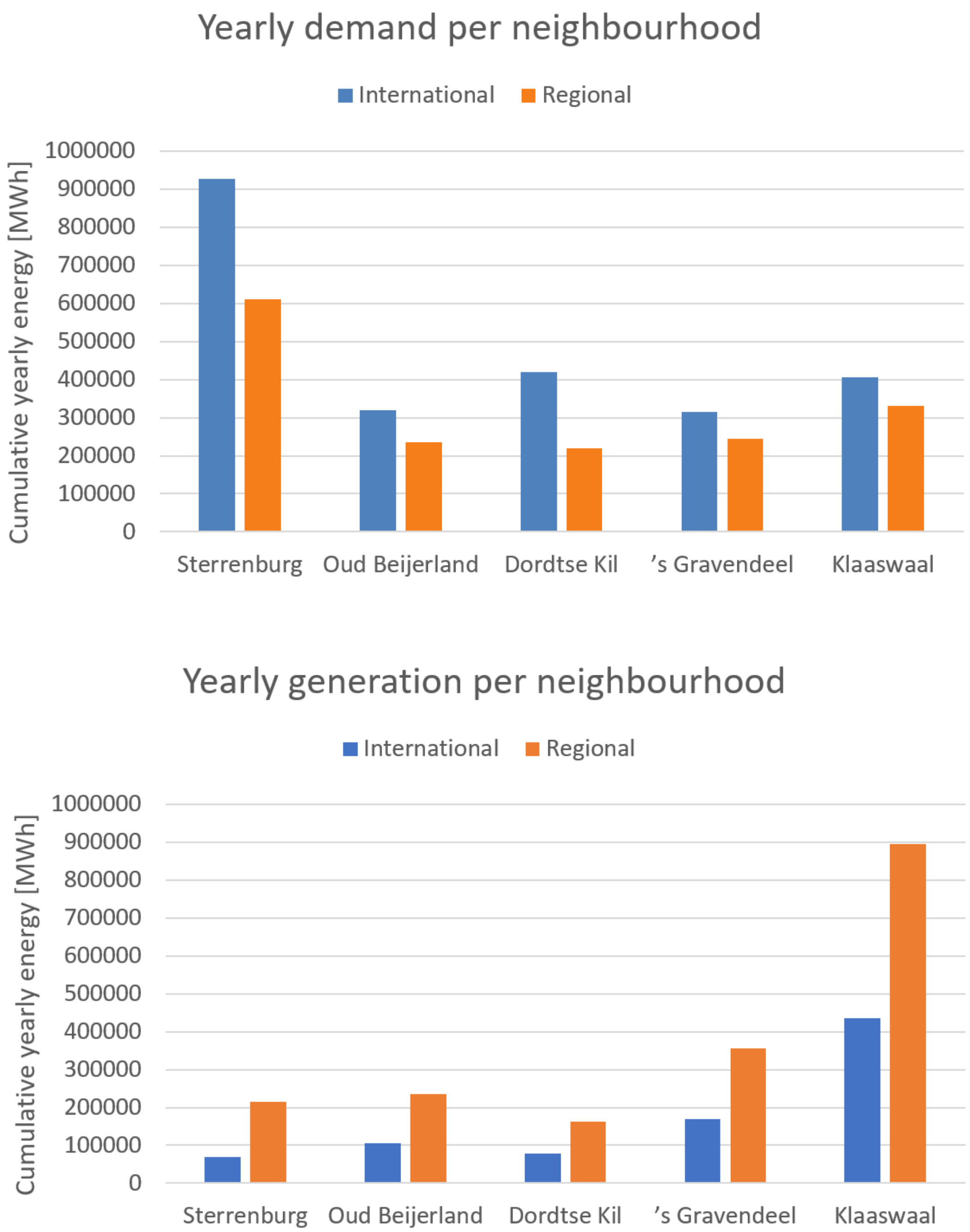


FIGURE 5.7: Demand and generation per neighbourhood

6 | Results & Discussion

This chapter presents the results of the case study. In section 6.1 the results of the base case are compared with the results of the reinforcement only scenarios, followed by the sensitivity analysis of section 6.2 and, finally, by the results of adding a thermal storage component in section 6.3.

6.1 Base case: international and regional scenarios

The first analysis of the case study is meant to compare the investments that would be needed in a so-called *reinforcement only* scenario, compared with the ones needed in the case of an integrated system such as in figure 4.1.
With *reinforcement only* it is intended a scenario in which the energy carriers remain largely independent, and therefore the investments are directed towards the single sectors (electricity, hydrogen, etc.) with the purpose of reinforcing them in order to have a system able to operate with the future demand/generation profiles. In the reinforcement scenario, therefore, the electrolysers and fuel cells are excluded from the optimization, which is then allowed to optimize the size of transformers, hydrogen substations, batteries and, ultimately the exchange with the external electrical and hydrogen markets. Furthermore, the assumption that in the reinforcement scenario no form of flexibility and cross-sectoral conversions are present, makes it complicated to argue how much of the heat demand will be satisfied by district heating and, most importantly, from which sources will this heat come from. Therefore, these values are taken by extrapolating the projected growth of the district heating network of Dordrecht, according to the estimations done by HVC Groep, its managing company. These projections run up to 2030 and assume, for the largest part, "conventional" sources of heat such as waste treatment, geothermal energy and gas burners for peak demand [55], and can therefore be assumed to be the most accurate indication of how the district heating network might evolve if one does not consider a strong "system integration" effect. These values of DH demand have been fixed in proportion to the total energy demand of the two scenarios, and are thus different in the regional and international case.
The two following tables summarise the main quantitative results of the optimizations. It should be noted that all the "Total annualised system costs" field in all tables refer to the net cash flow in the energy markets (costs-revenues) plus the annualised costs of all the assets in the system.

TABLE 6.1: Main results: regional scenario

	Reinforcement only		System Integration	
Infrastructure investments:	**Quantity**	**Yearly cost [€]**	**Quantity**	**Yearly cost [€]**
Tranformers & Substations [#]	15	9.639.121	13	8.351.934
Electrolysers [MW]	N.A.	0	252	13.021.069
Fuel Cells [MW]	N.A.	0	123	9.012.479
District heating infra [MWh]	120.000	2.285.291	476.544	9.075.350
Hydrogen boilers & heat pumps [MWh]	938.987	42.226.762	582.442	26.192.775
Hydrogen substations [MW]	0	0	0	0
Batteries [MWh]	587	8.129.491	147	2.035.835
Energy markets:		**Costs/Earnings [€]**		**Costs/Earnings [€]**
Electricity imports		38.691.085		105.622.789
Electricity exports		29.572.820		32.872.033
Hydrogen imports		10.775.797		8.779.287
Hydrogen exports		0		70.527.124
Total annualised system costs [€]		82.174.728		78.706.212

TABLE 6.2: Main results: international scenario

	Reinforcement only		**System Integration**	
Infrastructure investments:	**Quantity**	**Cost [€]**	**Quantity**	**Cost [€]**
Tranformers & Substations	12	7.723.119	12	7.723.119
Electrolysers [MW]	N.A.	0	117	6.065.812
Fuel Cells [MW]	N.A.	0	34	2.499.174
District heating infra [MWh]	160.000	3.047.054	252.391	4.806.573
Hydrogen boilers & heat pumps [MWh]	987.235	44.396.532	894.843	40.241.619
Hydrogen substations [MW]	33	53.752	18	29.319
Batteries [MWh]	0	0	0	0
Energy markets:		**Costs/Earnings [€]**		**Costs/Earnings [€]**
Electricity imports		95.532.926		112.935.725
Electricity exports		10.324.249		5.857.910
Hydrogen imports		58.396.626		36.800.015
Hydrogen exports		0		12.224.575
Total annualised system costs [€]		198.772.010		192.989.554

The first thing that stands out is that the total system costs, albeit showing a lower value for the system integration case, are not noticeably different: only around 5% cheaper.
Another overarching consideration that can be made is that the system integration scenario, albeit showing higher system costs imputable to assets (chiefly due to the addition of relatively expensive fuel cells & electrolysers), operates in a more advantageous way in the energy markets compared to the reinforcement scenario. This is mainly due to the fact that, even though electricity imports appear to be higher (driven by the demand from electrolysers), the need for hydrogen imports decrease and there is an additional revenue coming from selling the excess hydrogen (a revenue which is zero in the reinforcement scenario).

Regarding transformers, surprisingly, the installed capacity is similar in both the reinforcement only and in the system integration case.

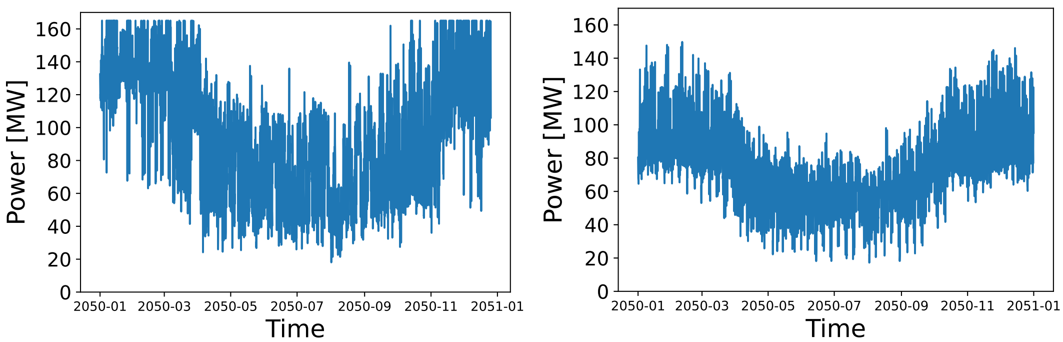


FIGURE 6.1: Loading on the Sterrenburg transformer in the system integration (left) and reinforcement (right) scenarios

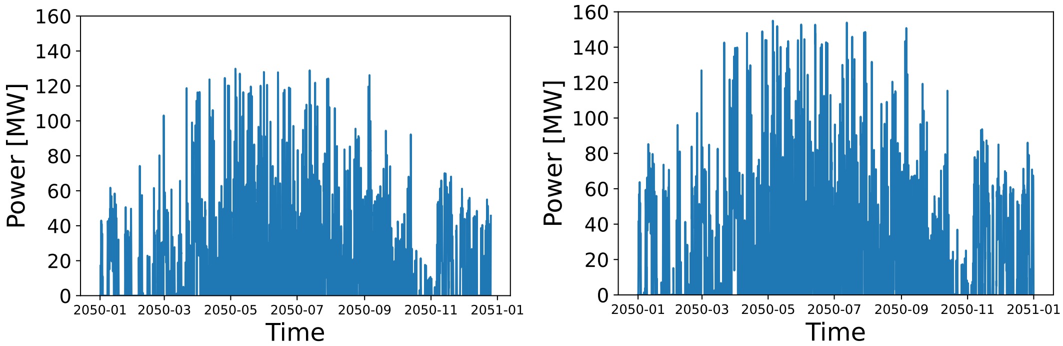


FIGURE 6.2: Loading on the Klaaswaal transformer in the system integration (left) and reinforcement (right) scenarios

In fact, in the International scenario the number of transformer investments is the same while, in the Regional scenario, system integration reduces the need of transformers by two units (or about 15%).
A distinction can now be made between neighbourhoods which have a lot of local generation and densely populated neighbourhoods with mostly demand. The previous two images serve as an example to explain this difference. The top one refers to the neighbourhood of Sterrenburg, which has many households and relatively little leftover area to install local generation systems, while the bottom one refers to the neighbourhood where most of the local generation takes place and where not many people live. From these images it can be seen how, in the residential neighbourhood, the loading on the transformer is a bit higher for the system integration scenario, while for the sparsely populated area with a lot of generation the higher transformer loading happens in the reinforcement only scenario. In the demand-driven area, the addition of electrolysers appears to be increasing the loading on the transformer because a substantial amount of electricity has to be imported for their use. Both hydrogen and heat demands are higher during winter, and that is why we see a clear seasonality pattern. On the other hand, the electrolysers installed in the Klaaswaal region help in reducing the loading on the transformer since they make use of part of the local generation output to generate hydrogen, reducing the need to export the excess electricity. As expected we can observe an opposite seasonality pattern, with an evident contribution of the local PV fields in the summer months.

It is also possible to observe how the optimization typically choses a lower amount of fuel cells compared to electrolysers. Even though their waste heat output is higher compared to that of an electrolyser, the fact that the hydrogen price is, on average, higher than the one of electricity, might be the main reason behind this behaviour. Therefore, if actual hydrogen prices will indeed look similar to the ones presented here, it could be argued that it will be unlikely that the majority of the hydrogen production will happen under a free market at distribution level.

Finally, it is interesting to note the stark difference in the optimal battery capacity between the regional and the international scenarios. While in the regional scenario this invested capacity amounts to 147 MWh, the international scenario seems to not have a need for these assets (0 MWh installed). The relatively high choice of batteries in the regional scenario can be explained by the fact that these components can complement electrolysers in storing the excess energy which in this scenario, as already discussed, is produced in great amounts. About 60% of the battery capacity is installed in Klaaswaal, corroborating this previous explanation. Regarding the apparent uselessness of batteries in the international scenario, this result should be of course taken with a pinch of salt, since it is derived from a simplified *grey-box linear optimization*. For example, this model considers only a wholesale electricity market and not, for instance a FCR, aFRR or GOPACS market, which are the primary markets suited for utility-scale batteries [80].

6.2 Sensitivity analyses

6.2.1 Share of district heating

In this work, two sensitivity analyses have been executed. The first and most relevant one consisted in changing the share of heat demand that must be satisfied by district heating, taking the base values from the international and regional scenarios, as discussed in section 5.3, and modifying them by -50%; -25%; +25% and +50%.
This analysis was done in order to see whether the share of district heating assumed in the scenarios is indeed the most optimal one and what effect does changing this parameter have in the overall system configuration.

TABLE 6.3: District heating share sensitivity analysis: regional scenario

	-50%	**-25%**	**+25%**	**+50%**
Infrastructure investments:				
Tranformers & Substations [#]	13	13	13	13
Electrolysers [MW]	193	223	371	444
Fuel Cells [MW]	77	89	147	178
District heating infra [MWh]	238.272	357.408	595.680	714.816
H2 boilers & heat pumps [MWh]	820.714	701.578	463.306	344.170
Hydrogen substations [MW]	0	0	0	0
Batteries [MWh]	302	268	64	29
Energy markets:				
Electricity imports [k€]	86.126	92.969	127.644	144.049
Electricity exports [k€]	28.261	28.836	31.999	33.794
Hydrogen imports [k€]	4.415	5.057	8.195	9.830
Hydrogen exports [k€]	48.692	56.917	98.251	118.693
Total annualised system cost [k€]	83.774	81.226	79.516	77.149

The first thing that catches the eye is that, with an increasing share of district heating, the annualised costs seem to decrease. With an higher share of heat demand to be satisfied by district heating, the number of optimal hydrogen conversion assets to be installed increases but, despite the higher capital costs of installing these assets, their operation on the markets (especially the hydrogen market) seems to be bringing economic benefit to the overall system. However, one should notice how a configuration with more district heating and electrolysers & fuel cells brings an higher exposure of the system to the revenues of the hydrogen market. Therefore, an unexpected reduction in hydrogen demand or in its price might quickly modify the economic favourability of such scenario.

TABLE 6.4: District heating share sensitivity analysis: international scenario

	-50%	-25%	+25%	+50%
Infrastructure investments:				
Tranformers & Substations [#]	12	12	12	12
Electrolysers [MW]	97	110	147	177
Fuel Cells [MW]	23	26	42	50
District heating infra [MWh]	126.195	189.293	315.489	378.587
H2 boilers & heat pumps [MWh]	1.021.039	957.941	831.745	768.647
Hydrogen substations [MW]	22.3	21.2	16.6	13.7
Batteries [MWh]	100	55	33	34
Energy markets:				
Electricity imports [k€]	113.390	116.316	118.207	123.744
Electricity exports [k€]	6.259	5.816	5.050	4.335
Hydrogen imports [k€]	33.535	31.785	35.589	35.288
Hydrogen exports [k€]	8.344	11.132	19.321	27.515
Total annualised system cost [k€]	195.065	193.156	191.269	189.541

The same sensitivity analysis applied to the international scenario shows a similar trend, as can be observed in table 6.4.

6.2.2 Battery cost

The uncertainty around the cost of transformers and hydrogen substations is quite limited, therefore a sensitivity analysis on their cost was deemed not very significant.
Surprisingly, also the cost trajectories of electrolysers and fuel cells were quite concordant, as seen in section 4.2. On the other hand, the cost of batteries currently has a quite wide range of price trajectories. Utility-scale batteries in 2050 are projected to have on average a cost of 150.000€/MWh, spanning up to more than 250.000€/MWh and down to slighly less than 100.000 €/MWh [59].
As shown in section 4.2, the main assumed battery price has been an optimistic 110.000€/MWh. The following sensitivity analysis is meant to investigate what would happen with a more conservative price, assumed to be 190.000 €/MWh.
Of course, only the regional scenario has been considered since, as seen, the optimistic price is still too high for any battery to be chosen in the international scenario. Applying this battery price to the regional scenario, the amount of installed batteries drops to 0 MWh, while electrolysers and fuel cells stay more or less at the same level at, respectively 249 MW and 121 MW. Without batteries, the operation of the system on the energy markets is slightly less favourable, and the total system costs are 79.512.870€, a 1.1% increase with respect to the base scenario.

6.3 Thermal storage

As a final analysis, a thermal storage component candidate has been added to the optimization.
Looking at the example figure 6.3, one can see how the optimal operation of fuel cells and electrolysers still produces noticeable amounts of excess heat that are absorbed by the heat sinks (ref. 4.1) and therefore not used by the system.

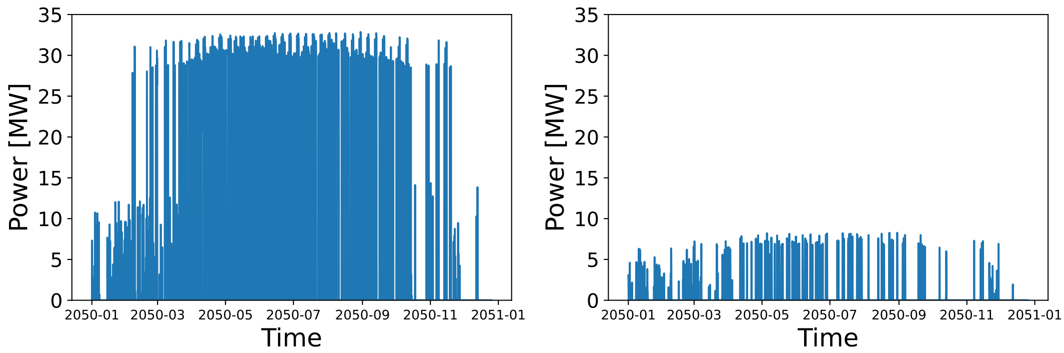


FIGURE 6.3: Thermal sink heat flow in Dordtse Kil in the regional (left) and international (right) scenarios

The first thing that can be noticed is how the waste heat flow is higher in the regional scenario: this happens, as expected, due to the higher number of fuel cells and electrolysers that are installed in this scenario and which therefore generate more excess heat.
The seasonality pattern is another element that can be observed: as expected, in summer more heat has to be sinked due to the reduced heat demand from the region. However, especially in the regional scenario, cheap electricity from renewable sources still encourages the operation of electrolysers to produce hydrogen.

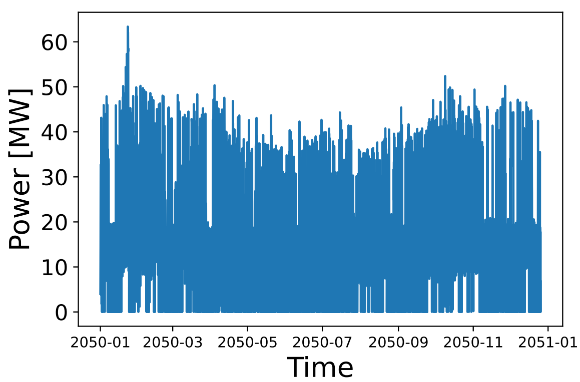


FIGURE 6.4: Hydrogen import in Dordtse Kil, international scenario

In addition, the cheap summer prices for hydrogen also encourage its import for the operation of fuel cells, which therefore add extra excess waste heat to the system. This can be observed in figure 6.4, where the hydrogen import for the example neighbourhood looks almost constant throughout the year, despite the reduced direct hydrogen demand during summer.

It is therefore clear how a further optimization of this heat flow should be considered. To see the effect that storing this heat could have on the whole system a candidate heat storage component has been added in the form of a water tank storage with the characteristics as discussed in section 4.1.

TABLE 6.5: Thermal storage effect

	Int	Int+TS	Reg	Reg+TS
Infrastructure investments:				
Tranformers & Substations [#]	12	12	13	13
Electrolysers [MW]	117	132	252	177
Fuel Cells [MW]	34	0.7	123	66
District heating infra [MWh]	252.391	252.391	476.544	476.544
Hydrogen boilers & heat pumps [MWh]	894.843	894.843	582.442	582.442
Hydrogen substations [MW]	18	18	0	0
Batteries [MWh]	0	0	147	0
Thermal storage [MWh]	0	1243	0	1683
Energy markets:				
Electricity imports [k€]	112.935	139.640	105.622	93.858
Electricity exports [k€]	5.857	3.513	32.872	28.995
Hydrogen imports [k€]	36.800	18.479	8.779	7.390
Hydrogen exports [k€]	12.224	26.398	70.527	56.732
Total annualised system cost [k€]	192.989	189.238	78.559	76.668

From table 6.5 it can be observed how adding thermal storage has a positive effect on the system on three main aspects: the total annualised are reduced in both scenarios, heat flows in the order of tens of MW are no longer wasted and, finally the power rating of the hydrogen conversion assets is decreased by about 15% in the international scenario and a surprising 54% in the regional.
Evidently, the addition of thermal storage covers the peaks of heat demand which were part of the drivers for investments in fuel cells and electrolysers: their functioning in the same system at reduced maximum power means therefore that they follow a more efficient load-duration curve.
In addition, it can be noted how the assumption of a 6h storage thermal storage (ref. 4.1) is greatly oversized in power. In fact, dividing the optimized thermal capacity by 6 would give power ratings that are far higher than the

peak heat demand in any of the considered neighbourhoods. Running an optimization without this constraint resulted in the same large values of thermal capacity but much smaller power ratings: the new capacity/power ratio settled to values ranging from 20 to 30.
A final consideration can be made on the spatial requirements of adding such large thermal storage capacities. Using [81] and [82] as sources for the spatial footprint of hydrogen conversion assets and water tank thermal storage, a comparison is being made in the following table between the case with thermal storage and without it:

TABLE 6.6: Thermal storage spatial effect

	Int	**Int+TS**	**Reg**	**Reg+TS**
Electrolysers/Fuel cells footprint [m^2]:	15.100	13.200	37.500	24.300
Thermal storage footprint [m^2]:	0	8.300	0	11.360
Total footprint [m^2]:	15.100	21.528	37.500	35.600

While the addition of thermal storage could be challenging from a footprint point of view in the international scenario, adding it in the regional scenario could free up about 2000 square meters.

7 | Conclusion

Following the detailed discussion of chapter 6, this conclusive chapter presents a summary of the main takeaways of this work, relating them to the research questions.

- *How can the flexibility provided by an electricity-gas-heat integrated energy system lead to advantages in distribution grid planning, as opposed to considering an electricity only system?*

  The introduction of a system integration between electricity, hydrogen and heat proved to have the potential for some savings in the overall system costs, compared to a "reinforcement only" scenario, ranging from 5% in the regional to 3% in the international scenario.
  The system integration has been achieved by adding electrolysers and fuel cells and linking the energy flows that originate or go into these components.
  To determine the optimal system configuration, a linear programming optimization using the python tool *oemof* has been executed, comparing its results to another, "reinforcement only", optimization run.
  Even though the cost attributable to the system's assets is higher in the integration case (especially due to the addition of expensive fuel cells and electrolysers), the operation on the energy markets (especially on the hydrogen one) lowers the overall system costs compared to the reinforcement only case. However, more exposure to the revenues from the hydrogen market could change the profitability of this scenario in case the price assumptions of this thesis were to greatly deviate in reality.
  The need for transformers did not show a substantial decrease when using a system integration approach. In fact, only the regional scenario showed a decrease of 14%, while there was no difference for the international scenario. This is due to the fact that in residential areas with a lot of demand, a substantial amount of electricity has to be imported and fed to electrolysers to cover the high hydrogen (and heat) demand, therefore the loading on the transformer is, at times, even increased. The opposite happens in areas with a lot of local generation, where the electrolysers operation helps in reducing the transformer loading, since less excess electricity has to be exported but can be used locally to produce hydrogen.

- *Which modelling aspects need to be considered when designing an investment & planning optimization model for such an integrated energy system, and how are these currently represented in literature?*

  A *grey-box* approach to the modeling of the main components of the system has been found to be the most common in literature, therefore also this work presented a simplified description of the technical aspects of the assets, focusing mainly on the interaction between each of them.
  Most of the papers trade the accuracy of the energy storage representation for more details in the modelling of the other components by clustering the input time series. Instead, in this work a simplified (linear programming) approach has been chosen in order not to sacrifice the integrity of the input data.
  The inclusion of energy markets in these type of researches is quite difficult to find in literature; therefore two models, one for electricity and one for hydrogen have been developed. The hydrogen market proved to be especially hard to model since there are little to no examples of how this market might look like in the future. For this reason, a set of well defined assumptions has been presented to describe the modelling approach in this thesis.

- *What is the potential role played by waste heat recovery from hydrogen conversion technologies (i.e. electrolysers and fuel cells), if combined to a district heating system?*

  In this work the heat output from the operation of electrolysers and fuel cells has been used as heat input for a district heating network in all of the city's neighbourhoods considered in the case study, covering 22% of the heat demand in the international and 47% in the regional.
  The feasibility of the final cost figures indicates that this might be an interesting way to use these hydrogen conversion assets in an even more efficient way. Due to the medium-low output temperature of the PEM assets considered in this work, this approach is especially effective if paired with investments in 4th generation district heating network since its operating temperature would be at a similar level.
  An higher share of heat demand to be satisfied by district heating brought, as expected, an higher need for electrolysers and fuel cells but, despite the higher capital costs, their operation on the energy markets brought a net advantage in terms of total system costs (about 2-3%). However, similarly to the base scenario, one should be aware that this comes at the price of an higher exposure to the revenues coming from the hydrogen market (60% more in the regional, 125% more in the international).
  Finally, it has been shown how the addition of thermal storage can have beneficial effects, helping in exploiting consistent flows of excess heat

which would otherwise be wasted and reducing the need for electrolysers and fuel cells by 15% in the international and 54% in the regional scenario.

- *How sensible are the results when considering the different long-term climate-neutral energy systems scenarios developed by Netbeheer Nederland? How does the optimal system infrastructure vary between these scenarios?*

  As seen in the first point, both the international and the regional scenarios show a marginal reduction in the overall system costs with a system integration approach. However, the higher share of local generation in the regional scenario leads to a few differences in the system configuration and in the market behaviour.
  Firstly, the optimal number of hydrogen conversion assets is more than double in the regional scenario compared to the international one. This is driven mainly by the installation of electrolysers used to absorb part of the local generation which instead would have to pass through transformers and sold to the external grid.
  The need to manage this higher generation is most likely also the main reason why the regional scenario presents a consistent amount of batteries while the international none (although, as mentioned, the rather simple approach to the electricity market might be the main reason behind this).
  Finally, the higher number of electrolysers in the regional scenario creates a bigger gap between the losses in the electricity market and the revenues in the hydrogen one (compared to the smaller gap in the international scenario).

Final thoughts:

While the overall reduction in costs does not seem to be particularly interesting, the author's opinion is that it could be still very valuable to commence initial investments plans in the direction of a system integration similar to the one presented in this work. Higher future hydrogen demand could be met by already present electrolysers and electrolysers and fuel cells could have a more advantageous price trajectory (similarly to what happened with the initial cost projections for PV and the current trends) thus making the business case more appealing. Finally, cheaper hydrogen conversion assets would likely lead to higher installation volumes, therefore having already developed an initial infrastructure and having acquired sufficient knowledge on how to valorise the consistent heat output from these assets could have a high future potential.

Grid operators cannot directly own assets such as electrolysers or fuel cells, but they can finance asset owners if their operation helps to solve grid problems. As shown in this thesis, the inclusion of hydrogen conversion assets could have beneficial effects on the electrical network, with the most important example of this being the load reduction on the Klaaswaal transformer thanks to the electrolysers. Therefore, further studies in collaboration with asset owners to analyse in more detail the extent of these benefits constitute another important suggestion. The priority for these analyses should be given to regions with the most consistent planned investments towards local generation because, as seen in this work, the effect of system integration is expected to be higher (i.e. regional scenario).

Another crucial aspect in which grid operators should put a lot of focus is the hydrogen market. In fact, the model presented in this work is simply an educated guess on how such a market might arise, but the specifics of how and when the first trades will take place remains completely unknown. However, as shown in this work, an hydrogen market could have a strong influence on the electrical market, potentially also driving investments on assets which would then have a direct impact on the electrical infrastructure itself. Therefore, this market has the potential to be both beneficial and detrimental to the electrical infrastructure. In fact, as seen, the operation of fuel cells and electrolysers modified quite substantially the electrical flows within the system and also with the external grid. With such an hydrogen market model, consistent investments in electrical infrastructure will still be needed and the expenses on the electrical market can be expected to be higher than the revenues (for a region similar to the one of the case study).
As soon as more details about the market will be known, further studies similar to this will be needed in order to optimally steer the specific system integration design approach.

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