Future Energy Carriers in Office Buildings

Techno-economic assessment of integrated energy and mobility systems

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Challenge the future

Future Energy Carriers in Office Buildings

Techno-economic assessment of integrated energy & mobility systems

by

C.C.A. Bleeker

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Abstract

In the energy transition the expansion of the amount of renewable energy resources requires new methods for the design of energy systems. To deal with intermittent energy production, different energy technologies and solutions are in development. Hydrogen is a main candidate for this goal. Using Fuel Cell or Battery Electric Vehicles as flexible power plants is a second potential solution. This thesis explores how these two concepts can be combined in an office environment. The goal was to design an effective, integrated energy and mobility system making use of renewable energy only. A simulation model was written to carry out techno-economic analyses on a set of concept system designs. These systems were designed in accordance with three scenarios that were analysed for two future years, 2025 and 2050. The scenarios were: hydrogen-based systems, electricity-based systems and combined systems. The model was applied to a case study of the Shell Technology Center Amsterdam, an office building in the Netherlands. In addition, the same analysis was done for a hypothetical case study featuring an average office building in the Netherlands. The results of each simulation are compared mainly by their System Levelized Cost of Energy, for which electricity, gas and thermal demands are taken into account. In the 2050 scenario, the system levelized cost for a hydrogen-based system is 0.056 €/kWh, for an electricity-based system it is 0.077 €/kWh, and for a combined system it is 0.049 €/kWh. The findings of this thesis implicate that hydrogen is a viable alternative to use as an energy carrier in office buildings and for seasonal storage of renewable energy. It can be used in combination with cars as power plants, which are mainly suitable for hourly energy balancing.

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Nomenclature

η	Efficiency
AE	All-Electric
BESS	Battery Electricity Storage System
BEV	Battery Electric Vehicle
CaPP	Car as a power plant
cf	Capacity factor
CO	Combined (Combined Hydrogen and Electric)
CoP	Coefficient of Performance
e	electricity (subscript)
FCEV	Fuel Cell Electric Vehicle
HE	Hydro-Electric
IC	Investment Costs
LCOE	Levelized cost of energy
LT	Lifetime
nZEB	(near)-Zero Energy Building
O&M	Operation & Maintenance Costs
Q	(subscript) Thermal Energy
Q	Size / Capacity
SCOE	Specific cost of energy
SFC	Stationary Fuel Cell
SLCOE	System Levelized cost of energy
TC	Total Costs
TSC	Total System Costs
V2G	Vehicle-to-Grid

1

Introduction

Our world is changing faster than ever before. Since the industrial revolution, technological advancements brought us incredible welfare and provided rapid economic growth. We harvest energy in various forms for our daily needs, such as electricity, heat, production of goods and transportation. The roots of our current global energy supply lie in the use of fossil fuels. This foundation, however, now has to change too.

Because of increasing environmental problems and the inevitable depletion of fossil fuels a transition has to be made to a renewable energy system [1]. A renewable energy system uses sustainable sources that do not harm the environment and do not deplete. Fossil fuels played the main role in the creation of the current society and infrastructure, but they will now have to be phased out. While preserving our current standards on the access, affordability and reliability of energy, we now aim to develop our future energy systems completely CO_2-free

The Paris Agreement in 2015 [2] set targets for global emissions with the ambition to limit global average temperature increase under 1.5˙ C. The energy sector is the primary contributor to global warming, mainly because of its constant release of CO_2 in the air [3]. The European Commission aims to reduce CO_2 equivalent emissions by 95% in 2050 [4]. Therefore, nations seek climate adaptations mainly in reducing emissions in the energy sector. Multiple pathways are available to obtain these reductions, and we will have to implement a combination of these options to reach our emission goals.

1.1. Problem statement

Strategies for the transition to sustainable energy systems often include three major (technological) changes [5]:

- Replacement of fossil fuels by renewable alternatives.
- Efficiency improvements in energy production and transmission.
- Energy savings on the demand side.

These three pillars are complementary, but also provide their own particular challenges. As our energy systems and demands become increasingly complex, it is best to aim for synergy between the different aspects of our energy system.

Renewable Intermittency

The greatest challenge lies in expanding the share of renewable energy in the supply system. Currently, renewable sources such as wind and solar embody just a small portion of the total energy supply. Their potential is very high; the available energy from renewable sources is more than enough to meet global demands. The core issue lies in the inherent intermittency of most renewable energy [6]. To maintain an robust system, sufficient energy needs to be available at all times. Yet, energy production should not exceed demand: the functioning of electricity grids is heavily dependent on a match between energy supply and demand.

Higher penetration of renewable energy sources greatly increases the difficulty of balancing the electricity grid. Photovoltaic (PV) Solar and wind energy are viewed as the key technologies to decrease the fossil fuel share in our energy supply. State-of-the-art projects have proven to be cost-competitive with traditional power plants [7, 8]. Unfortunately, both have the same drawback: they are entirely dependent on variable weather conditions for their energy production. This highlights the need or energy storage while using renewable energy sources. Moreover, being unable to control their output, flexibility needs to be introduced in other parts of the system. Providing this flexibility is one of the main barriers in the large scale integration of renewable energy [9].

Rising total energy demand

Energy demand is expected to increase in the following decades, mainly due to population growth. Most of the direct energy needs for individual humans stem from either buildings or transportation: the built environment is responsible for about 40% of global energy demand (30% CO_2 emissions) [10–12]. In the Netherlands, electricity demand in the built environment rose from 26 TWh to 115 TWh between 1995-2013. 20% is consumed by the residential sector, the rest is taken by commercial sector [13]. Thus, improving and reducing the final energy demand in the built environment potentially has a large impact in redesign of our energy infrastructure.

Energy in transportation

The transportation sector is another very significant contributor to the global energy demand producing 22% of global emissions in 2008. Road transport accounts for about 75% of the energy demand in this sector [14, 15]. The sector is also growing in a faster pace than most others with projections of emissions having doubled in 2050 (since 2015), primarily because of high adoption rates of passenger vehicles in countries such as China and India [16]. The challenge lies in providing emission-free transportation that has the same accessibility as our current transport.

Cleaner substitutes for road transport have become more readily available in recent years, but require a shift in infrastructure. The most common alternatives, such as Battery Electric Vehicles (BEVs) or Fuel Cell Electric Vehicles (FCEVs), use an electric motor instead of an internal combustion engine. When these types of vehicles become dominant, we need to be able to charge and refuel them, reshaping the energy demand side by mainly increasing electricity demand (using BEVs) or hydrogen (using FCEVs) [17, 18].

These highlights show that there is a need to solve the challenges arising in the energy transition in the coming decades. Fortunately, a large variety of solutions are being investigated.

1.2. Potential solutions in the energy transition

With the three pillars highlighted above, in this section we will discuss some of the ideas that could conceivably solve a share of the challenges that we face in the upcoming transition. The ideas below are by no means a comprehensive list of solutions, rather a selection that we will focus on in this study. Yet, this selection is made because the approaches below potentially have a high level of synergy. This synergy will be explained later in Section 1.3, which will set the premise for the research setup.

1.2.1. The use of hydrogen

Hydrogen is a versatile energy carrier that can be produced emission-free. The potential use cases are widespread: It can be used as a storage medium, as a fuel for transportation or for electricity demand (after conversion by a fuel cell), or as feedstock in industry. Electrolysis and fuel cells are the key technologies in operating systems based on hydrogen. Historically, these technologies were only implemented in niche markets and did not gain much attention for energy purposes. However, with the changing characteristics of the energy sector, arguments for the use hydrogen technology are growing stronger [19–21]. Some of the main hydrogen use cases are the following:

- (Seasonal) electric energy storage and transport
- High temperature heat and steam for industrial purposes
- For space heating in built envrionment
- Transportation

Hydrogen is the most abundant element in the universe, but does not exist naturally in pure form. Two major ways are possible to produce hydrogen: Derivation from fossil fuels and water electrolysis. The first option is not considered since this study is about renewable energy systems. Water electrolysis is the splitting of the water molecule (H_2O) into gaseous hydrogen (H_2) and oxygen (O_2). This process consumes electricity [22]. Using (surplus) wind and solar energy, we can produce 'green' hydrogen suitable for purposes such as (seasonal) energy storage and transportation.

Hydrogen is a smoothly scalable storage medium for intermittent wind and solar energy storage. Coupled with wind turbines or solar PV systems it can be produced with exchess electricity that cannot be used directly. Later, during electricity deficits it can be converted back to electricity using fuel cells. The main drawback of this process is that this process is relatively inefficient: With current technology, more than 50% of electricity is lost during the two conversion steps [23–25].

Yet, there are numerous advantages too: Transport and storage of hydrogen can be much more economical than storage of electrons. Gas pipelines are cheap and have no losses. Storing hydrogen in salt caverns (a process currently common the natural gas industry [26]) provides huge storage capacities with very little costs [27, 28]. Finally, companies and institutions are investigating concepts of large centralized decidated hydrogen production plants at locations with cheap renewable potential (e.g. Australia). These concepts show similarities to our current fossil fuel infrastructure, which could possibly ease the integration [29–31].

Using the current infrastructure, hydrogen could be a suitable replacement for natural gas. Proponents exist for both heating via fuel cells and replacing gas directly (burning

H_2) [32]. In Europe, the heating and cooling sector is the largest single energy user (50% of final energy demand). 42% of this demand comes from natural gas alone [33]. Accordingly, an extensive gas pipeline infrastructure is in place throughout the EU. Research suggests that replacing natural gas by hydrogen is possible, with only minor adaptations. Most infrastructure can be retrofitted for the use of hydrogen [34–37]. Thus, hydrogen potentially also has a crucial role in reaching sustainable thermal energy.

Last, hydrogen is often considered as a fuel for road vehicles. The reasoning used in previous paragraphs is generally applicable in this sector as well [17]. FCEVs have lower efficiencies than BEVs, but have advantages in other areas: The high mass energy density of H_2 makes it possible to design long range lightweight vehicles (which is useful for freight transport), and fueling infrastructure could be similar to what we have currently [38]. Research suggests that with large-scale implementation, FCEV fueling infrastructure would also be cheaper to maintain than its main emission-free competitor (i.e. the BEVs infrastructure) [39]. These characteristics are strong arguments for implementing hydrogen for transport.

1.2.2. The potential of buildings as smart energy components

In the future, buildings can participate much more actively in the national energy system. On the one hand due to decentralized generation, for example with rooftop solar power [40, 41]. On the other hand, buildings can assist in mitigating the fluctuations in the energy system by demand response management [42]. Sustainability strategies for the built environment often include the concept of (n)ZEB, near-Zero Energy Buildings. nZEBs are designed aiming for annual net zero carbon emissions by the building [43]. These measures usually have benefits for both the building owners and the grid operators.

Distributed or decentralized generation technologies consist of three categories: heat, electricity and combined heat & power (CHP). Examples include solar and (micro-) wind for electricity, heat pumps for heating, and (bio)gas CHP plants for CHP [41]. The advantages lie in being less reliant on the grid, often meaning lower costs for the owner. On a national level, transmission and distribution costs are reduced with increased distributed generation. Distributed generation does not necessarily consider only one building, but can consist of a small array of energy components and loads instead. These systems are referred to as microgrids, and can often provide grid flexibility when needed, benefiting users and transmission system operators [44].

Next to this, a service that could be provided by buildings and microgrids is demand response management (DRM). DRM is a set of measures that can be taken to improve the consumption side of energy systems [42, 45]. These measures can be controlling loads to reduce or increase energy usage when this would be advantageous for the balance of the total system. Grid operators can provide incentives to this behaviour by financial compensation. An indirect form of demand response management is energy efficiency: by installing more efficient components energy demand is reduced permanently.

A combination of DRM and local generating components contribute to the design strategy of nZEBs. Achieving this means that in the future the linear electricity grid infrastructure can be redesigned to a more dynamic, meshed grid [43].

1.2.3. The expanding role of vehicles in energy systems

Expecting that the world phases out internal combustion engine (ICE) vehicles in favour of sustainable alternatives as BEVs and FCEVs, which can play an important role in integrated energy and transport systems. On the most basic level, vehicles will commence claiming a part of the electricity demand for producing hydrogen or charging BEVS [46]. By its own this aspect already indicates the need for electricity grid redesigns [47]. However, the establishment of these new vehicle types into our energy systems also provides us with new chances for smarter integration.

The electrification of vehicle motors means that every car essentially becomes a small electric power plant. If cars are parked, it is possible to let it generate power for other purposes. In the book *"Our Car as Power Plant"* A. van Wijk & L. Verhoef introduce the radical concept of using FCEVs as a generating component, instead of only as a consumer of energy [48]. Cars are parked for more than 95% of the time [49], meaning that in theory, using the car as power plant (CaPP) idea enables us to have an abundant capacity of electric power at all kinds of locations.

Both FCEVs and BEVs can be used for this purpose, with their own advantages and limitations. Often referred to as Vehicle-to-Grid (V2G), EVs are capable of offering flexibility and selling energy to the grid, BEVs can also operate the opposite way: Providing a form of energy storage when needed. This is subject to some drawbacks, as BEVs battery capacities are often the limiting factor, as well as battery degradation that should be considered. This is explored in numerous studies, e.g. [50, 51].

FCEVs are less prone to the drawbacks that BEVs have for this purpose. As hydrogen fuel tanks usually have an energetically higher capacity than their BEV equivalents, they can be used for longer durations, shown in experiments done by Robledo et al. [52]. Robledo et al. also show that FCEVs are a good way to reach the nZEB targets mentioned in Section 1.2.2. Thus, in the integration towards future smart renewable systems, FCEVs could play a vital role.

1.3. Holistic energy systems

Energy systems become increasingly interconnected and complex and hence, no single solution or problem should be viewed by its own. Instead, we should opt for **holistic** designs of our energy systems.

For a holistic design, by its definition, we should evaluate systems as wholes rather than analysing or separating them into parts. In the context of energy, we should consider that design choices in our energy systems impact the requirements and costs of associated components, thereby making good combinations is essential.

Creating **cost-effective** solutions has always been the number one priority in the energy sector. The viability of system designs is heavily dependent on the financial costs, and the cheapest form of energy generally dominates the market (which is why coal is still the most used resource for electricity generation) [53]. Competitive renewable systems must thus have the lowest **total** costs as possible.

We should therefore not just look at cost of generation, but take into account every part of the energy chain. For example: A very large wind park will have significantly lower costs per energy unit than a small local solar system. However transporting the wind energy to the same location may increase costs so much that it eventually still exceeds the costs of the local decentralized system. Therefore, the concept of **System**

Levelized Costs of Energy (SLCOE) was developed (see Section 3.1.2), to enable us to fairly compare energy systems.

1.4. Research question

The focus of this research is on the concept design of an integrated energy and mobility system in a live environment, starting with the controlled environment at Shell Technology Center office in Amsterdam. The main research question is:

"How can we effectively design a 100% renewable integrated energy and transport system using both electricity and hydrogen as energy carriers for an office, starting with the control environment at Shell Technology Center Amsterdam?"

Smart and holistic energy system designs were explored recently with designs of integrated energy and mobility systems: Oldenbroek et al. (2017) evaluated a hydrogen-based smart city design, emphasising the use of FCEVs as power plants [54]. They showed that hydrogen-based designs compare favorably towards other fully renewable systems. Continuations on this study have been carried out in modelling efforts by Farahani, Salet, Nordin and Oldenbroek [55–58], where they analysed more profoundly how employing hydrogen, CHP and V2G can contribute to smart energy systems.

Developments in energy system design

Their case studies indicate that a good holistic energy system has a high degree of flexibility and features both long and short-term energy storage in it. Their system designs mostly relied on using hydrogen as the main energy carrier in the system. Hydrogen was stored for long-term seasonal storage in salt caverns, and FCEVs were used as flexible short-term power plants. Yet, these were hypothetical designs and a logical next step is to evaluate how well such systems could integrate in a real-life environment.

The research findings above imply that it is worth continuing to delve into the designs of hydrogen-based and FCEV-based energy systems. A relevant addition to these ideas would be to progress towards an actual physical system design in operation. The first step involves designing a system at a site where the chance of implementation is high. After the design phase, the second step is to start a pilot project, constructing the design that is proposed.

Office buildings are a good environment to test such a design. Offices feature many of the aspects explained above: They can be designed as nZEBs and actively participate in the electricity network (see Section 1.2.2, they usually have car parks that could be integrated in the design and they have an energy profile that contributes directly to the intermittency issues.).

Another continuation is to start directly comparing hydrogen-based systems to other approaches. It is important to consider all options in designing energy systems, therefore a side-by-side comparison could be a valuable addition to this field of research. The previous designs emphasised hydrogen, but a system prioritising electrons as energy carriers could also prove to be favourable. A third possibility is a mixed system: Selecting a set of components that creates a system using both energy carriers. As we saw in the previous sections it is valuable to analyze different solutions. From this comparison we can expect that hydrogen is probably more feasible for seasonal storage purposes, but electric-based components are more energy efficient. Thus, these may have lower costs in some cases: generating and using electricity directly is presumably more cost-effective.

But when we consider the system holistically, taking into account transport and storage, using hydrogen should prove to be competitive. Ultimately, exploiting the advantages of both pathways by combining them should achieve the lowest costs.

1.5. Research approach

To answer the main research question we need to explore several topics. These topics were reformed into the following actions:

1. **Identify renewable energy components that are either hydrogen- or electricity-based and review their technical and economic parameters.**
2. **Defining different scenarios using the components identified in the first step, and using different energy carriers, i.e. electricity and hydrogen.**
3. **Use data to model the energy profile of the case study and construct realistic energy demand flows.**
4. **Develop a set of energy system designs per scenario using local and external components from 1. and the energy profile from 2.**
5. **Evaluate what would be a good resemblance is of a future national, 100% renewable energy system.** Investigate the required changes to. Determine how office buildings will exchange energy and operate within this network.
6. **Perform a techno-economic assessment of the designs and the sensitivity analysis..** Evaluate the results.

The research consists of comparing scenarios on multiple axes. The main contrast that is depicted in the research is the hydrogen-based vs. electricity-based scenario. Two different years are considered, near-future (2025) and Mid-Century (2050), to take into account future efficiency and cost projections for components.

1.5.1. Case study: Shell Technology Center Amsterdam

This research used data of the Shell Technology Center Amsterdam (STCA). This building is a 100,000 m^2 site featuring laboratories, test halls, workshops and offices. Here, 1,000 employees work on R&D projects in various technologies. With the designs in this study, the building should serve as a self-sustaining ecosystem by also having an energy storage system readily available. In addition, the transition to only EVs for employees is made in parallel in order to have the carbon-free mobility system as well.

As STCA has a different energy profile than the average office building due to their laboratories, a second case study was done for a hypothetical office building in the Netherlands. The energy profile of this office building was based on average values for offices in the Netherlands applied to the data from the STCA case study.

1.6. Report outline

After this introduction, this thesis is divided into five chapters. In Chapter 2, the system design and scenarios are explained. Chapter 3 elaborates on the modelling techniques used, and on the data preparation during the system design phase. Subsequently, Chapter 4 shows the results, evaluating the different scenarios and designs. The discussion, recommendations and conclusions are presented in the last two chapters.

2
System and technologies description

This chapter explains the final designs of the systems and how those designs were reached. First, a review is done of relevant technologies for this system. Secondly, we discuss the decision-making process on the development of the designs. Next, the design overview section establishes the complete system designs for every scenario to obtain an overview. In conclusion, we approach components separately showing the reasoning behind technology decisions and sizing aspects as well as some economic parameters.

2.1. Scenarios

This research investigates a set of 12 scenarios (Fig. 2.1). We aim to design a 100% renewable energy system in an office environment, integrating mobility in the system and exploring the options of different energy carriers (hydrogen and electricity). The economics of these solutions are the most crucial factor in the energy sector, so the start of the study is to make a comparison between a Hydro-electric and All-Electric scenario. In practice, we are anticipating a scenario where both will be available, where systems have integrated both hydrogen and electricity technology, optimised for lowest costs. That is why we also investigate a ”combined” scenario where we can start integrating using the best results from the two extreme scenarios.

Furthermore, we will investigate this scenarios in two periods: A near-future case, for which we take the year 2025 as a reference, and a mid-century case, where 2050 is the reference year. The near-future case is intended to be an evaluation of the system if we would build it now or in the coming years. The input parameters will reflect the current state-of-the-art or short-term projections of technology characteristics. The mid-century case is proposed to incorporate future developments of technologies, and assumes most technologies have matured in performance and costs. Also, in this scenario the requirements for this system such as 100% renewable energy are actually realistic to expect in this period.

On top of this, we decided to also include one case where we generalise the input data to an average Dutch office. Since STCA has a very case-specific energy profile that is much larger than you would expect from an office, it is good to include this scenario

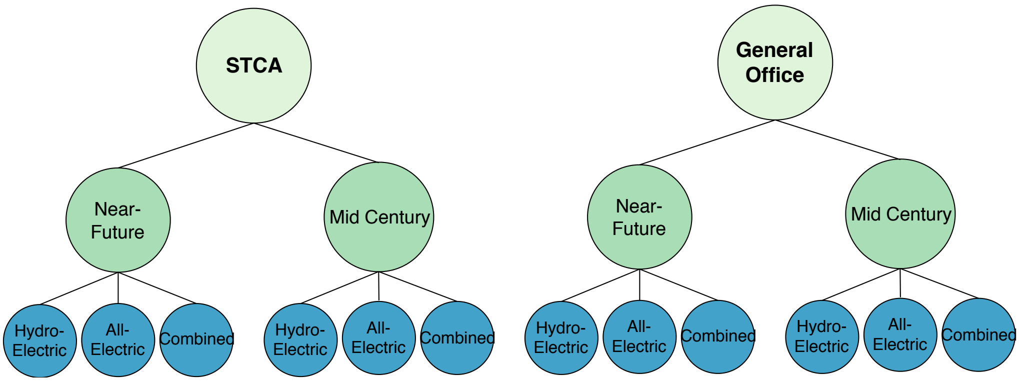


Figure 2.1: **Diagram of simulated scenario combinations**

when one wants to compare results with other research.

Hydro-Electric

In the Hydro-Electric case we aim to include as many hydrogen-based technologies as we can. Also, the only external grid connection that the building has is a H_2-grid. No electricity grid is available. Vehicles that are present in the building consist of 66% FCEVs and 33% BEVs.

All-electric

The All-Electric case is the opposite of the hydro-electric case. No H_2 grid available, only the electricity grid. 66% BEVs and 33% FCEVs. We aim to electrify all energy components.

Combined

In the combined case all technologies were available, as well as both grids. 50% FCEVs and 50% BEVs. Aim to select the most suitable technology for the case, regardless of electric or hydrogen based.

2.2. System Components Description

In Table ?? a summary is shown of cost parameters used on a per-unit basis. If BEVs had been charged outside the office and this energy is used inside the building for V2G, we assume the costs for charging is 0.25 €/kWh in 2025 and 0.15 €/kWh in 2050. The near-future costs assumption expects a mix of home charging (22 cts /kWh) and public charging (30 cts/kWh) and fully incorporates costs for chargers, just as we would for charging inside the building. These costs reduce due to technological and scale improvements in the Mid Century case. For FCEVs using fuel from external sources costs are assumed to be 6 €/kg and 4 €/kg in 2025 and 2050, respectively. A report by JÜlich Institute in 2018 calculates that Wind-Hydrogen based systems are able to reach 6 kg/H_2 in a scaled system (from a fleet of 1 million FCEVs, using surplus renewable electricity) [39]. Again, these costs reduce by one third in the 2050 scenario. Salt Cavern costs are based on research by Bunger and Michalski, the calculations and assumptions can be found in App. Aet al. and [27, 28] Table 2.1 displays every component used in the model with their respective economic parameters. These will be further explained in the following subsections.

Components	Near Future (2025)				Mid Century (2050)			
	η or cf [%, -]	**IC** [€/kW]	**O&M** [%/y]	**LT** [y or h]	η or cf [%, -]	**IC** [€/kW]	**O&M** [%/y]	**LT** [y or h]
Electricity production								
PV System [8, 59–61]	0.10 cf	725	2.8	25	0.12	440	2.3	30
Wind turbine [62–64]	0.59	1728	2	20	0.59	1390	2	30
Hydrogen production and transport								
Electrolyzer [25, 65, 66]	77%	480	2	20	82%	200	2	30
Compressor [67, 68]	1.5 kWh/kg	8060	4	15	1 kWh/kg	3440	2	15
Hydrogen consumption								
Stationary fuel cells [69–71]	60%η_e/20%η_q	512	2.5	60000 h	65%η_e/14%η_q	200	2.5	90000 h
Heating and Cooling Components								
Hydrogen boilers (kW heat) [72]	97%	100	1.3	35	100	1.3	97%	35
Air-conditioning system (kW heat) [73]	4.13 COP	240	4.3	21	4.43 COP	240	4.3	21
Heat pump (kW heat) [72, 74]	4.1 COP$_avg$	700	0.7	20	4.2 COP$_avg$	490	0.7	20
Electric components								
Lithium-ion Batteries (BEVs) [75–78]	73% total	96	1	79.92 MWh	95% total	70	1	249.75 MWh
Stationary Batteries Systems (BESS) [75–77, 79, 80]	87% total	300	1	10	95% total	210	1	15
Vehicle-to-grid components								
FCEV stack Replacement Costs [54, 69, 81]	51%η_e	40	1	4100 h	61%η_e	26.5	1	8000 h
FCEV discharge infrastructure [60]	-	6400	5	15	-	3200	5	15
BEV chargers (bi-direct) 2-point [39, 82]	-	9500	5	7.5	-	5000	5	10

Table 2.1: Component Parameters for model analysis. All efficiencies are calculated using HHV.

Component	Unit	Costs 2025 [€]	Costs 2050 [€]
Salt Cavern Storage	kg^{-1} H_2	1.79	1.57
External Grid Battery	kWh^{-1}	0.155	0.09
H_2 grid infrastructure (see 2.2.15)	160 kg/h	19.8k (HE)	19.8k (HE)
E-grid infrastructure (see 2.2.15)	10 MW	216k (AE)	216k (AE)
External charged BEVs [39]	kWh^{-1}	0.25	0.15
Externally fueled FCEVs [39]	kg^{-1} H_2	6	4

Table 2.2: **Fixed cost parameters for energy services used in the model.**

2.2.1. Wind turbines

The costs and performance of off-shore wind turbines is highly dependent on site parameters as water depth, distance to shore and wind speed profile. The aim is to model wind turbines that resemble the real wind turbines built at Wind park Borssele IV, off the Dutch coast. This wind park was initiated and partly owned by Shell [83].

For the wind speed profile data of Dutch institution Deltares was available. The dataset consists of hourly data of wind speed (at 10 m height) and direction from 1992-2011 of metocean study report of Wind Park Borssele IV [84] . In this research, we used the most recent year, 2011.

Wind profiles generally follow a trend throughout the year: In Northern-Europe, there is significantly more wind in the colder seasons of the year. This thus creates a large seasonal imbalance in the energy generation throughout the year. 58.6 % capacity factor wind turbine (direct output)

As we will not need an exact 12 MW turbine for this energy system, it is assumed that there is a wind park with these wind turbines, where we can own a specific desired capacity meeting our demand. The power generated by this capacity is simply calculated by taking the ratio compared to a single wind turbine. The power pattern and intermittency is maintained and is fed into the energy system as if it was part of the system. More on the calculations on the wind turbine can be read in App A Section A.4.

2.2.2. Electrolyser

Alkaline electrolysers have been the dominant technology in large-scale electrolysis. Experts argue that PEM electrolysis will become the dominant electrolysis technology by 2030, however advantages lie mainly in that they are more flexible and have shorter startup times. For a large-scale off-shore system of energy alkaline is still the better technology [65, 66]. The target price for PEM electrolysis in 2024 is 700 €/kW [25] and 450 for mid-century. For alkaline the price for near future is determined at 480 €/kW and mid-century at 200 €/kW. This leads to significantly lower costs than PEM technology, despite the disadvantages in performance. In table 2.3

Characteristic	2025	2050
Costs [€/kW]	480	200
Avg. η (in HE-Case) [kWh/kg H_2]	51.122	47.9

Table 2.3: Key component characteristics of electrolysers [25, 65, 66]

Currently, the idea of producing hydrogen off-shore directly is gaining interest, with potential use cases for existing gas networks and obsolete oil platforms. This seems technically feasible but it still has to be proven in practice. The issue of space is important, and reliability is another interesting topic. Alkaline is therefore a safe technology choice for venturing offshore with hydrogen production. The electrolysers are placed directly or near the wind turbines off-shore, and are connected to the gas network to transport hydrogen to the mainland.

An alkaline electrolyser is used for producing hydrogen offshore directly coupled with the wind turbine. We assume a power conversion efficiency from the wind turbine to the electrolysis components (also the compressor) of 0.9/0.95 in both the time scenarios. As an example for our modeling we use the largest unit currently available: the NEL A-485 alkaline electrolyser. A 2200 kW unit, which is able to produce at a rate of 42.3-48.9 kWh/kg (DC) [85]. These electrolysers also produce at a pressure sufficient for a H_2-grid. Investment Costs were set at 480/200 €/kW with a 2/1 % O&M cost (2025/2050). Lifetime is assumed to be 20 / 30 years (2025/2050).

No efficiency curve for the NEL electrolyser was available so a replacement curve was used approximating the values for the unit used, the curve was from a 200 kW electrolyser of ITM Power. Minimum Power requirement was set at 330 (15%). In the model a total electrolyser system efficiency is reached of 51.1 kWh/kg in 2025 and 47.9 kWh/kg in 2050.

2.2.3. Auxiliary components hydrogen production

Next to the electrolyser, compression and water treatment is needed. The compressor connects the electrolyser to hydrogen sea pipelines that bring the produced gas to the shore. To calculate the energy requirements for compressor, methods from Meier et al. [86] for off-shore electrolysis compression to sea pipelines were replicated. Pressure requirements can range from 75-300 bar, as a simplification we assume 100 bar is needed. This leads to an approximation of the compressor consuming 1.5 kWh/kg in 2025 and 1 kWh/kg in 2050 (See Eq. A.1 in App. A). Thus, about 2% extra energy is needed for production. For 2025/2050 respectively, investment costs were set at 8060/3440 /kg, O&M costs at 4/2 % and lifetime at 15/15 years [67, 68].

As the electrolyser is placed on the sea, we can purify seawater to use as input for the electrolyser. We calculate the maximum amount of water we need per day and use that to design the purification unit. For the pure water tank a storage of 2 days of water is used [87–90].

2.2.4. Solar PV system

Solar energy is an economically very effective option for local energy systems in the Netherlands. Grid-connected PV systems are already popular way to reduce the energy footprint of the built environment [91]. The Solar PV system has an investment cost of 725 €/kW and O&M costs of 2.8% and 440 €/kW with 2.3% in 2025 and 2050 respectively (see Table 2.1 [8, 60, 61]. The lifetime is set at 25 years and 30 years. Standard module sizes are assumed with crystalline silicon technology. The whole roof is filled. In the Netherlands, systems are usually facing south. Although in some situations it may be better to install them in an east-west array, to better match energy demand when it is needed, at the edge of the day. While numerous cell types are still being developed and brought to market, it was decided to select conventional crystalline-silicon modules, because of their proven market worth and well-known cost developments [59].

2.2.5. Heat Pumps

Assuming that the heat pump has become a developed technology nowadays, Heatpump costs lie in the range of 490-1100 €/kW$_{heat}$ for the 0.5-10 MW range (larger systems have lower specific costs). Operations & Maintenance costs are found at 0.7 % per year and the lifetime is 20 years [72]. For our system of 3.3 MW we can estimate an investment cost (IC) of 700 €/kW. Other examples include [74] where similar values have been found in a techno-economic analysis.

In the near future case the heat and cooling demand of the building is assumed to be the same as it is now, since STCA uses state-of-the-art technology which will not be much different from the average technology in 2025. In 2050 however, we see a decrease of 10% in heating demand. When using heat pumps the power consumption is therefore lowered 10% as well in the months October until April. This is not completely accurate since in the threshold months there is also cooling activity, but this effect is not very significant in the total model.

2.2.6. Battery Electric Vehicles

In contrast, for BEVs a completely different approach is necessary. BEvs need to charge instead of fuel, which currently can take up to 12 hours to reach a full charge. Many users charge their cars overnight at home, or at a public charging station. Another option is at work, or at a fast-charger which is located at a petrol station. Robinius et al. [39] carried out a comparison for multiple scales of adoption of either FCEVs or BEVs determining the effects on infrastructure costs. They demonstrated that for low market penetration levels (few hundred thousand vehicles) the infrastructure roll-out costs would be about the same. For higher levels of adoption (20 million vehicles) the BEV infrastructure becomes approximately 25% more costly than hydrogen infrastructure. This is mainly devoted to the time needed to charge BEVs, meaning that more charge points per vehicle are needed. An additional advantage of hydrogen infrastructure is that it simultaneously provides seasonal energy storage.

For batteries we assume a price of 96 €/kWh and 70 €/kWh (2025/2050 for battery replacement costs in BEVs. O&M costs are estimated at 0.6%. Lifetime is very dependent on how the battery is used [92], in this study it is assumed that with a fixed charging/discharing rate, their lifetime ends after 80 MWh of energy produced in 2025, and 250 MWh in 2050 [56]. Material costs currently consist of 70% of total battery pack costs, about € 70. But most reports concur that with economies of scale these costs for BEV batteries are reasonable [75–78].

Battery pack capacities are assumed to be 60 kWh in near future (small car), of which 48 kWh we can use. For mid-century we assume 100 kWh and 80 kWh usable energy. This is because of the DoD importance in degradation prevention and the ability to drive elsewhere after use. We maintain a 20% capacity threshold for BEV minimum capacity. In 2025, this means 12 kWh, and is effectively about 100 km of driving with a an average state-of-the-art BEV [39].

2.2.7. Bidirectional Chargers

Charging infrastructure naturally accompanies BEVs and are a requirement for BEVs to function. Currently, many offices in the Netherlands provide BEV charging points in some form already. Chargers are, however, expensive to install and therefore usually a limited number of chargers is constructed at each site. The cost of installing charging infrastructure is dependent not only on the chargers themselves, but we should also include the Energy Management System (EMS) and, in large cases, potential costs for additional power line capacity and transformers. A wide variety of charging capacities is used, with motor freeway chargers going up to 350 kW, and domestic or office chargers usually having a capacity between 3 and 11 kW. Investment costs range between 45,000 € for the freeway chargers down to 750 € per charger for domestic installations [39].

Bi-directional chargers are chargers that enable vehicles to also discharge energy back to the grid or load. These types of chargers are still in their technological infancy and only pilot or experimental projects are currently in operation (some examples can be found in [82]). Currently, bi-directional chargers are fives times more expensive than single-directional chargers [82].

The model uses 10 kW 2-point bi-directional chargers (2-point meaning that two 10 kW vehicles can be connected at once). Note that higher power capacity chargers would be more costly. Costs for auxiliary infrastructure are assumed to be included in the costs for the chargers. In the model these chargers are 100% efficient and any losses are incorporated at the BEV itself in (Section 2.2.6). The O&M costs and lifetime are seemingly unappealing, degradation of the inverters inside chargers are the main cause of these values [39].

2.2.8. Stationary Battery Systems

Stationary battery systems are gaining much attention in recent year for dealing with various energy issues. In this research we are specifically looking for two types of stationary storage:

1. A large seasonal type of storage. This system is able to handle long periods of surpluses and deficiencies and has high storage capacity.

2. A local stationary storage system that provides flexibility to the local user in the form of back-up power, going off-grid or other short-term response. It could also be used to store solar energy locally.

Battery types

Choice of battery type is very dependent on how one plans to use the battery: High discharge rates, long lifetime or high efficiency are all important factors that can be weighed specific to the project. In this design it is primarily important that the battery systems are capable of high power rates and can store large volumes of energy. Efficiency is less of an issue. Costs are of course also essential. An oveview of battery types can be found in App. A Table A.3 which reviews the key values for some of the more popular battery options, such as lithium-ion and vanadium-redox (also called flow batteries).

Salt Batteries

One novel technology is salt batteries, which are potentially able to provide cheap and large scale storage in the future. Next to the batteries mentioned above, a novel technology in the energy storage field is the concept of water-salt batteries. Main advantages of these types of batteries are that they are potentially low-cost and very sustainable in the scope of material use, as the batteries primarily exist out of just salt and water. Disadvantages show in the low energy density and low maximum power capacity.

Salinity Gradient Power (SGP) is power derived from mixing two water sources with a different salt concentration. This is done by the use of ion-exchange membranes and works bi-directional. Opportunities of power plants using seawater are explored in [93, 94]. Here it seemed that economically feasible projects could be reached with brine water (high salt concentration, usually higher than natural sea water). Concentration Gradient Flow Batteries (CGFB) are creating this environment artificially by adding salt to water. While cheap, they have drawbacks in energy density, which is only 5 kWh/m^3. Lifetime is better than other batteries and is estimated at 20 years. This battery type's lifetime is not affected by the amount of cycles [95]. Currently, the largest power plant reaches a 1 kW maximum power. The largest challenge for this type of battery is getting a good Power:Storage ratio. These batteries are cheapest and perform best with a low Power:Storage ratio. In this research we need a relatively high one. To put this technology in perspective: Lithium ion batteries reach 300-400 kwh/m3 in recent years, state of the art batteries about 600 kWh /m3 [92, 95].

Model decision: Lithium-Ion Battery Storage

Mismatches in supply and demand between Wind and STCA lie between 1-10 MWh on an hourly basis. Lithium-Ion currently is one of the few technologies that provides this high power rates, so technologies like flow batteries or salt batteries are not applicable. Also they have a very large size, which would be suitable for the external storage system, but not for the internal BESS.

Cost for BESS are given in the overview table: Investment costs are at 400 and 210 €/kWh (2025/2050), O&M at 1%, lifetime is assumed to be 10 years and 15 years [75–77, 79, 80].

2.2.9. Salt cavern storage

Hydrogen can be safely stored on a large scale in Northern-Europe by using natural salt caverns. This simple concept makes use of empty space in caverns and fills them up with hydrogen gas. Salt caverns are particularly suitable for the storage of hydrogen due to their physical properties. The tight structure of salt formations enables stable and safe storage options over longer durations [27]. For the purpose of seasonal storage, which requires both long term stability and large capacities, salt caverns are an appropriate an economically effective option. In this research we project the costs for storage at 1.79 €/kg H_2 and 1.57 €/kg for Mid-Century [28].

In the Netherlands, salt caverns are mainly present in the north-east of the country. This should not pose a difficult problem since we currently also have a big gas hub in that part and the developments around hydrogen are accelerated exactly in that location. The extensive gas infrastructure should be sufficient to store this hydrogen in that part. In the context of a hydrogen network that is established, it is assumed that this network is directly connected to the salt caverns. Any compression costs are all included in the storage costs and are not considered separately. It is argued that energy can be transported directly between supply and demand. This is reasonable because it is part of the larger national system. But we still need to account for the mismatch between supply and demand at certain times.

A large hydrogen-based network does not purely have to rely on its own production, because H_2-carrying ships could be a solution that is in line with current infrastructure. Currently, from locations with abundant fuels ships are constantly tranported to areas which import fuel. The same can be done with renewable hydrogen. The hydrogen could be produced at a location with high solar irradation or high wind speeds, meaning cheap electricity. This hydrogen can afterwards be exported to other areas overseas, making a global hydrogen economy a feasible idea [23, 70].

2.2.10. Stationary Fuel Cells

With the objective of covering the base electricity load and providing extra heating for the building, Stationary Fuel Cells are proposed. Currently, stationary fuel cells are rarely used as a main electricity producer in buildings. There are examples in pilot plants, but it is currently still a niche application, largely due to hydrogen technology in general not being very popular yet [71].

However, a promising example can be found in Japan, where Stationary Fuel Cells are employed in households in micro-CHP systems. Manufactured by Panasonic, ENE-Farms domestic FC CHP systems are already being employed. Target prices for those systems are 6000 € / kW for 2020 [96]. These are relatively small systems compared to what is needed in this research, only scaled up to 1 kW. Therefore, it is reasonable to assume that these costs can be brought significantly lower with economies of scale and lower auxiliary costs per system. Staffell and Green [97] in 2013 consider the Japanese Government targets most realistic with a 3018 €/kW price target that has to be reached between 2020 and 2030. This however again considers domestic systems. This study also argues that the **fuel processor costs form 80% of the Balance of Plant (BoP) costs**. The balance of plant costs are then 61% of total system costs. With a hydrogen grid with all hydrogen produced by electrolysis we actually do not need fuel processing costs, therefore we can remove these.

Fuel Cell sytsems have much room for cost reductions, and can be brought down to 40 €/kW or even 30 €/kW, US DOE argues [69]. However, we have to consider that this is a SFC that also collects the heat, therefore we should consider those costs too. Assuming a 1000 € / kW price in 2025 without 48.5% fuel processing costs, we arrive at a system that costs 512 € / kW. These investment costs improve up till 200 € / kW in the 2050 scenario. It is worth to notice the similar cost assumptions with SFC and electrolysers, as they are, of course, similar technologies [24]. More can be read on the costs of SFC in App. A.6

2.2.11. Hydrogen Boiler

The first hydrogen boilers have already been developed by some Dutch companies like Remeha, and results look promising. The technique is similar to that of natural gas boilers [32]. For the hydrogen boiler is is assumed that the price is the same as a natural gas boiler. The price of a natural gas boiler lies around 100 € / kWe at this capacity and the O&M costs are about 1.3%. These are taken for both 2025 and 2050 [72]. The boilers mentioned in the paper are meant for district heating but are in the same capacity range as we need at STCA. Efficiency is 97 % HHV.

2.2.12. Rooftop airconditioning

For rooftop airconditioning we assume a price of 240 €/kW and 4.3 O&M costs for near-future and mid-century. These costs are derived from an American research [73]. Coefficient of Performance (CoP) is 4.13 in 2025 and 4.43 in 2050.

2.2.13. Fuel Cell Electric Vehicles

Fuel cell Electric Vehicles (FCEVs) are electric vehicles which use hydrogen as a fuel by converting it to electricity. Vehicles basically consist of an electric motor, a fuel cell and a high pressure hydrogen tank. A group of large car manufacturers is developing new types of these cars, such as the Hyundai NEXO, Toyota Mirai and there are also FCEV trucks being developed by a company called Nikola. For FCEVs we follow the methods and studies of previous studies in this group, as seen in [54, 56, 57]. Costs for replacing fuel systems are estimated at 40€/kW or 30 €/kW in 2025 and 2050 respectively. This is assuming a 500,000 production units per year.

Currently, there are thousands of petrol stations evenly spread over the country. For FCEVs this setup can remain roughly the same, but the stations need to be able to deliver hydrogen. As hydrogen is a gas which needs to be stored and fuelled at a high pressure, this complicates the process of fueling the cars. Not many hydrogen fueling stations are operational as of today and building them is relatively expensive. Also, a viable supply chain of (renewable) hydrogen needs to be established to supply these stations, either via trailers or maybe via underground gas networks. An advantage is that for end users the changes are not very significant.

2.2.14. Discharging infrastructure

Discharging infrastructures for FCEVs is defined by the connections built to enable the H2-Grid connection to the FCEVs fuel cell directly, as well as discharge connections for FCEV2G. The costs for these are assumed to be 6400€ per 4-point connector and 3200€ respectively in the mid-century scenario. OPEX cost are set at 5% and lifetime to 15 years for both timescales [60] .

2.2.15. Grids

In the scope of this research we need to define a method to determine costs and capacity for the particular grid use in this system. This component is different because the grid is not a direct component in the designed system but a part of the national system. Users of the grid are required to pay for the costs of their part respectively. For this reason the costs for the grid use will be defined as a cost per kWh or cost per kg H_2. It is expected that these costs change over time, so also the costs in the near future and mid century case will be treated separately.

Two methods were explored to find this number, explained in more detail below. In literature, future projections of grid costs are diverse and very case-specific. Research on this relies on many assumptions which makes numbers not easily transferable to a different project. For example, the EU estimated electricity grid costs to increase from 3.7 cts/kWh to 5 cts/kWh, but this number is based on EU-wide averages and technology roadmaps made by Entso-E (The european network for transmission system operators, electricity) in which no mentioning was made to V2G services [98, 99].

A more practical approach is to look at the current costs specifically in the Netherlands for case-specific grid connections and base our calculations on that. In the Netherlands, grid distributors are semi-public institutions, meaning the costs they charge for maintaining the grid is without profit. Therefore, this number is chosen as the main indicator for the grid costs for this research.

Hydrogen Grid

The largest assumption for this determination is that costs for the hydrogen grid is equal to costs for the natural gas grid. As there are no real examples of national hydrogen grids no accurate, verifiable numbers are yet to be found.

The Netherlands has an extensive natural gas network in place which can be retrofitted to a hydrogen network without much extra costs. The largest natural gas field in Western Europe lies in the Northern province of Groningen and has been one of the major suppliers in the European gas market. Historically, this has led to the Netherlands having built an elaborate gas grid that is connected throughout the complete built environment. In recent years, however, societal and political pressure has raised to reduce or phase out the gas production. Environmental concerns were strengthened by acute issues of induced seismicity causing earthquakes in the region [100]. Consequently, the government has decided to phase out gas production in the coming decade and find a more sustainable strategy for this region [101].

Candidates for replacing natural gas are hydrogen, biogas and electricity. Stakeholders as Gasunie (gas extraction) TenneT (transmission operator) and net distributors desire options where existing knowledge and infrastructure can be maintained. Research shows that centralized production of green gases are most promising in this regard [102, 103]. Hydrogen, provided that some economical barriers are overcome, is seen as the most favorable option for large-scale replacement of natural gas. The variety of implementations and the opportunity of blending hydrogen in the existing gas network makes it suitable for near-future introduction [34, 36]. No large scale projects have been completed yet, but first explorations indicate that it is feasible to retrofit existing infrastructure into a hydrogen grid with minimal extra costs [35, 37, 104].

Some considerations need to be made in the transition to a hydrogen grid, mainly because of the difference in physical properties between hydrogen and natural gas. Table A.5 in the appendix gives the main properties that determine the feasibility.

With the goal of transporting the same energy content through an existing pipe, we see that we need to triple the velocity of the flow. This value is reached because of the determining factors of density and energy per volume. The density is 9 times lower for hydrogen and the energy content per volume 3 times lower.

First results indicate that running this higher velocity will not pose major problems for the gas transmission and distribution network [37]. The current capacity remains the same with constant diameters and pipes. Of all current pipes established in the Netherlands only those made of steel or PE (polyethylene) are suitable for use with H_2 [35]. Fortunately, all pipes built after 1970 were made with this material. Approximately 90% of assets of one of the larger net distributors (Stedin) is of these types and this number is similar with other distributors. The older material types pipes are mainly located in old city centers and are often way past their economic lifetime [104]. On the transmission level, most pipes are made from steel. Some concerns are raised about permeation, noise problems (due to higher speeds), erosion and safety. These should be further investigated but appropriate measures are already proposed [35].

Along these points, it is reasonable to state that the costs for maintaining a potential hydrogen network is similar to maintaining the current gas network. Considering the evidence that the same energy content can be transported with the current infrastructure, this research will use the current tariffs and costs for the natural gas grid to calculate the costs for use of the hydrogen grid.

Calculating tariffs

The current capacity for the gas grid connection is 834 m^3 per hour. In the model we calculate a different capacity, according to how much kg H_2 we need. The reference values for these calculations can be found in [105].

Electricity Grid

The electricity grid is calculated in the same way as just was explained for Hydrogen grid. As STCA already has a 10 MW connection, we will assume that we have to account for this connection. This leads to yearly costs of: 216k€. Electricity infrastructure has some transport losses connected to them. Two types of losses were identified: Losses per km cable and losses per power conversion step. The wind turbine producing AC power, we need to convert to DC for the power transmission to the shore [106], and subsequently back to AC for the national grid. For the 2050 scenario we assume we just need one conversion step (the wind turbine incorporating DC output in its system). We assume a 3% conversion loss for each of the two steps, based on standards by International Electrotechnical Commission (IEC) [107]. Total transmission line losses are estimated at 4.5% (assuming 70 km of HVDC cable to reach the shore, and 150 km HVAC lines. 2.3%/100 km losses for HVAC lines and 1.6 % for HVDC lines both for 2025 and 2050 [108]). These losses are combined in the following equation:

$$\eta_{e,Grid} = \eta_{AC \to DC} \cdot \eta_{DC \to AC} \cdot \eta_{line,HVDC} \cdot \eta_{line,HVAC} \tag{2.1}$$

where $\eta_{AC \to DC}$ is only applicable in 2025. Total power grid losses $\eta_{e,Grid}$ were determined to be 10.2% in the 2025 case and 7.4% in 2050.

2.3. Design overviews per scenario

The following section shows how each design was constructed within their unique characteristics. Most designs involve modelling from the baseload (idling load) of STCA first, but it depends on what options are available. The design overviews are listed before the components are, so one should consult Section 2.2 for clarification on specific components.

2.3.1. Hydro-Electric Design

In Fig. 2.2 the overview of the hydro-electric design is shown. For each component their rated power or capacity is shown. With FCEVs and BEVs the value represents the maximum amount of cars used at one timestep. The salt caverns capacity is higher than what is actually used, which is explained in the description section (Section 2.2). Two out of four local electricity generators are supplied by H_2. Fig. 2.3 explains in what order components are employed by the system. This order is also the reasoning for the higher amount of FCEVs than BEVs used in total.

The design starts by looking at the local system, and evaluating how much energy is needed in the form of electricity, heating, cooling and direct gas. When this is known, firstly we employed the solar system to respond to the electricity demand. The electricity demand always exceeded the solar production, so we could start the next design step with the leftover electricity demand, the solar subtracted.

In the Hydro-Electric case the base load coverage is shaped by a Stationary Fuel Cell (SFC) connected to the H_2 grid. The fuel cell systems in Fuel Cell Electric Vehi-

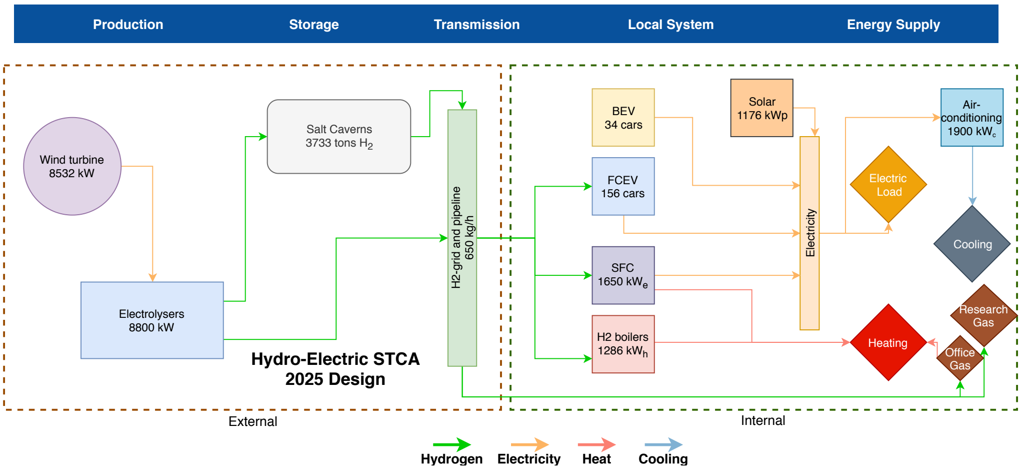


Figure 2.2: **Schematic system design of Hydro-Electric STCA Scenario 2025 displaying components in system and their capacities.**

cles (FCEVs) are used to convert hydrogen from the H_2-grid to electricity, during peak loads where solar and the SFC are not sufficient. We assume that these fuel cells can be directly be connected to the grid, so the fuel tanks of FCEVs are not depleted in this case. If FCEVs are still not sufficient for the energy demand, BEVs are used for V2G having charged batteries that were charged externally. They have charged for fixed market price of 0.25 € / kWh in 2025 and 0.15 €/kWh in 2050. Each BEV arrives with a specific State-of-Charge (SoC) (see description BEV) that depletes when used.

Hydrogen boilers in combination with rooftop air-conditioning are used for thermal demands. No viable alternative was found for cooling with hydrogen. Research gas and office gas (= secondary heating) demands are directly fed by the hydrogen grid. The hydrogen coming from this grid is produced by an off-shore wind turbine supplying electricity to an electrolyser (also offshore), and the electrolyser is connected to the same grid.

By determining the local usage of SFC FCEVs and H_2 Boilers, the hydrogen production facilities are dimensioned by the simulation model to match the demand in a year. With an approximation, a wind turbine capacity is calculated, then a sufficient amount of electrolysers is installed. Note that the electrolysers are selected in a per-unit basis of 2200 kW, that is why the capacity is slightly higher than the wind turbines. This is however not a large problem because the efficiency is also higher when not operating at full capacity.

The wind speed at the wind turbine dictates how much hydrogen is produced, and the assumption is made that this hydrogen can instantly be used at STCA. However, the demand and supply are constantly mismatched, requiring a balancing system. This

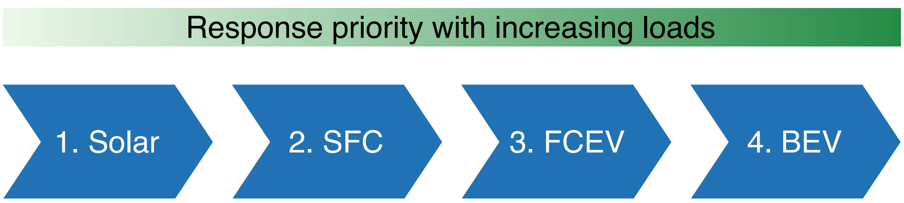


Figure 2.3: **Dispatch priority of local component in supplying electric load for Hydro-Electric system design.**

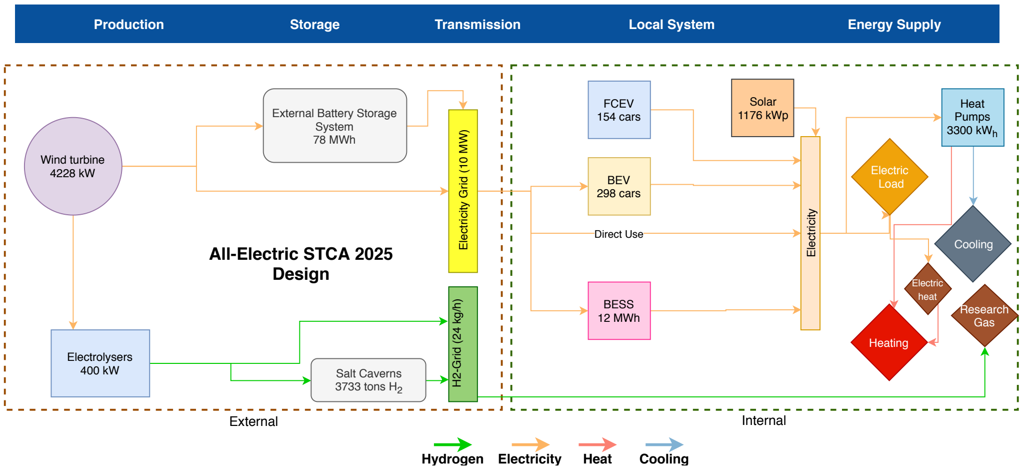


Figure 2.4: **Schematic system design of All-Electric STCA Scenario 2025 displaying components in system and their capacities.**

balancing system is designed in the form of a salt cavern that is also connected to the grid, where we can store any surplus hydrogen or obtain hydrogen if the production is too low.

As the system design is based on match between the total yearly supply and energy, we can calculate the total amount of energy that needs to be stored by taking the sum of either all surpluses or all shortages of energy in a year. In this case we look at the H_2 produced by the electrolyser vs. the H_2 consumed at STCA. The salt cavern is used to store the energy. This is a shared salt cavern, so the 3733 tons that are displayed is the total capacity of the cavern, not the amounts that is stored in this simulation. Instead, costs are allocated for each kg of H_2 that needs to be stored. The storage level in the salt cavern is assumed to be adequately filled at the start of the year, but is required to be approximately equal at the end of the model simulation. The hydrogen requirements of STCA command the sizing of the wind turbine and electrolyser(s).

2.3.2. All-Electric Design

The transition to the future energy system is currently leaning to the electrification of all energy consumers (e.g. heating, transportation). The ambition is to research whether an energy ecosystem can be constructed which has a balanced flow between local generators and loads using the concept of CaPP.

In this scenario one main design is proposed and one alternative design, having other characteristics. First, introducing the main design, we should note that both an electricity grid and a hydrogen grid are present (Fig. 2.4). As no all-electric alternative could be found for the incinerator, the decision was made to include hydrogen for the research gas purpose only. The hydrogen system works in the same manner as is explained in the Hydro-Electric design.

Next to focusing on the use of electricity-based components, in this design emphasis is also put on a decentralized approach: Making more use of local storage and local generation when possible. For FCEVs in this case (as there is no hydrogen grid) the hydrogen from their fuel tanks is used to produce electricity.

The system primarily relies on the direct electricity from an off-shore wind turbine. Serving as balancing systems, Battery Electric Vehicles (BEVs) and a Battery Electric Stationary Storage (BESS) can both be charged in this design in the case of wind energy surpluses. They are discharged when there is a deficit in the wind electricity (see Fig. 2.5). The BESS simultaneously has the function of a back-up power system. FCEVS are also used in this design, but now the fuel tank is used to provide the hydrogen, which can of course deplete. If the first four options are still not sufficient to provide electricity demand or store the surplus, an external storage system is invoked.

Note that in the All-Electric case, surpluses in energy are being dealt with by:

1. Charging BESS until SoC = 100%.
2. Charge BEVs until full.
3. Use External Battery Grid Storage.

This is an essential discrepancy between the HE and the AE case. This external storage system represents a large BESS, and is the salt cavern equivalent of the all-electric scenario. The 78 MWh is for the shared battery and costs of storage are assumed to be 0.16 /kWh (including input electricity) in 2025, for example. However, in the all-electric case this system is only used as a last resort after local storage, while the salt cavern is used as a primary storage system.

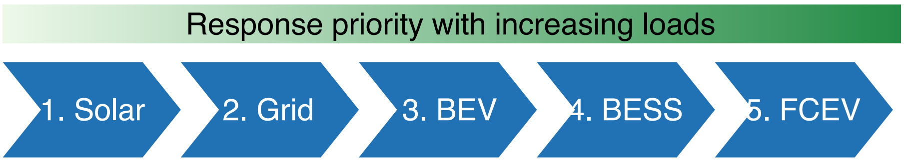


Figure 2.5: **Dispatch priority of local component in supplying electric load for All-Electric system design.**

Alternative design: Large internal battery system

As much attention by the energy field is given to local battery systems and microgrids, this simulation evaluates a system where we have a large internal Battery Electric Storage System (BESS). This was, in fact, one of the first designs that was tried in this research for this scenario, as it seemed logical. The BEVs are also included as a secondary storage medium. Why in the end the other main design was chosen can be read in Chapter 4. In this internal battery design the goal is to see if we can completely deal with the intermittency in the system with only local storage.

In this design a simple grid trading aspect was added additionally, because initial results (Sec. 4.1.3), showed that the storage was insufficient. This trading is represented in the model by buying energy on the electricity market for 6.4 cts/kWh (this is the $SLCoE_{Wind,e}$ in the main All-Electric design) whenever a deficiency occurs. In surplus events, electricity is either sold for 0 cts/kWh or curtailed (which is essentially the same). We chose this price for selling energy in the assumption that probably the electricity market is dealing with the same surplus.

2.3.3. Combined Design

In the combined scenario we also have one main design but three alternative designs, to show what explorations were done. In the combined system it becomes evident that the main design is based on the lowest possible number of components, also making use of existing components as the heat pump, as seen in Fig. 2.6. Also, the aim is to use as much as energy as possible directly, leading to the prioritisation shown in Fig. 2.7.

The wind turbine produces for both grids. Only when a surplus occurs and electricity cannot be directly used, wind electricity is allocated to electrolysis. This hydrogen is then either stored in salt caverns or used by one of the hydrogen components locally.

The salt cavern storage was chosen as the main storage medium because of its huge capacity of storage, which is useful throughout the seasons. Compared to the all-electric option costs are lower: storage costs per kWh are only 4.5 cts/kWh (converted from HHV), instead of the 0.18 cts/kWh for battery storage. Of course, we have to consider

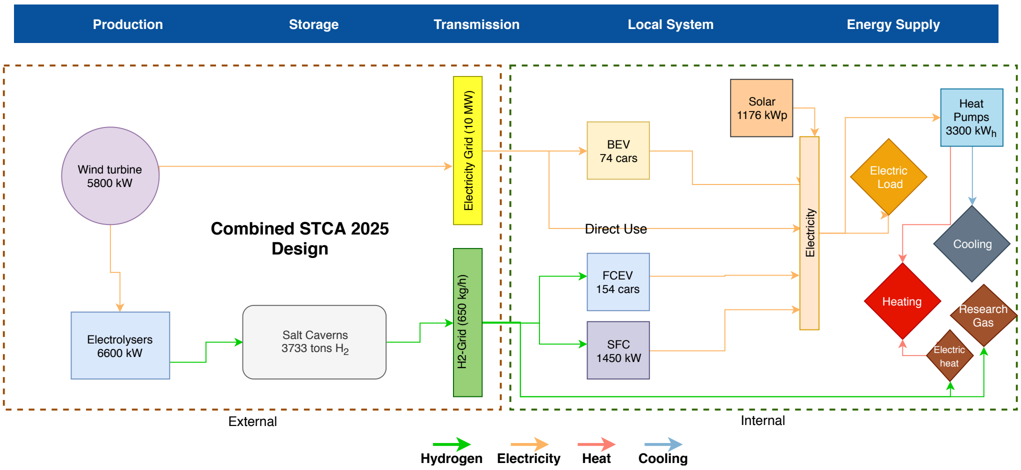


Figure 2.6: **Schematic system design of Combined STCA Scenario 2025 displaying components in system and their capacities.**

Alternative Design 1: replacing heat pump by boilers and airconditioning

In this simulation the aim is to find out if it is more cost-effective to omit the heat pump and deal with the thermal demands with hydrogen technologies, like in the Hydro-Electric case. The rest of the parameters and setup remains constant.

Alternative Design 2: prioritising vehicles in V2G mode

A design where we switch the priority of electric generation locally. This proposal is meant to check the effect of increasing the role size of vehicles in the energy system. Especially in offices, it could be preferable to not need to add an additional component as an SFC, or be able to operate independently. The rest of the system was kept constant to evaluate this priority change.

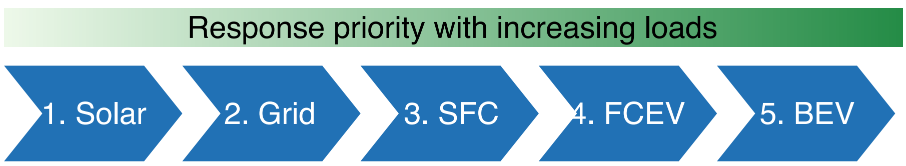


Figure 2.7: **Dispatch priority of local component in supplying electric load for Combined system design.**

Alternative Design 3: Fixed buying costs H_2 and electricity. Emphasise H_2 + SFC use

This experimental design involves some different methods, starting with a reduction of scope: Only the internal system is regarded here. We assume that we can buy hydrogen and electricity from the grid with a fixed price, ignoring the calculations for the wind turbine, storage and grid costs. Instead, we use the System Levelized costs of electricity and hydrogen calculated in the two extreme cases. This alternative approach is added for greater simplicity of the design, by only looking at local components.

Additionally, this design emphasises the use of the SFC by putting it as a priority before using the electricity grid. The SFC heat is collected like in the Hydro-Electric case. The purpose of this change is to evaluate whether the increased heat collection reduces the total system costs. The total heating costs should be lower because less usage of the heat pump is required, which is more costly than the 'extra' heat of the SFC.

It seemed inconsistent to completely disregard wind energy fluctuations in this simulation. To maintain a situation where the system has to cope with renewable intermittency, we assume that grid power buying availability is dependent on the wind profile. The maximum amount that the system can buy from the electricity grid at a specific timestep is equal to the wind power of a 3800 kW wind turbine at that timestep. This capacity corresponds to the All-Electric case wind turbine size as well as approximates the base energy consumption over the year. If the grid demand exceeds capacity, the system switches to FCEVs and BEVs.

To summarize, the system operates like this:

1. The system operates the SFC constantly at 1400 kW electric power, heat is collected for the thermal demands. The hydrogen fuel is bought from an infinite H_2 grid with the costs of the HE-case €/kg.
2. After solar and SFC, the system prioritises buying from the electricity grid when it is available. Buying electricity costs the same as $SLCOE_{wind}$ in the AE-case. This power can only be bought when there is sufficient wind power produced by a 3800 kW wind turbine at Borssele.
3. If the grid is insufficient then the system employs FCEVs and / or BEVs, analogue to other designs in this research.

2.3.4. General office scenario designs

The same concepts and methods were applied in designing the office systems. Because the office input parameters are a derivation of the original dataset, the patterns and requirements remain mostly the same, the change lies in the size of the system. This means that the designs described earlier can also be used in this scenario: by changing only the capacities of the components we can design the office system.

There are some requirements however that were not necessary to design for anymore, the most important ones listed below:

- The research gas is not necessary in this scenario, thus removing one hydrogen demand flow. For the All-Electric case we are now able to completely leave out the hydrogen connection.
- Also the gas allocated to the office for secondary heating such as moisturization and kitchen purposes seemed too high from the data when compared against average

values for office buildings. It was chosen to omit this stream in 2050, but include it 2025.

- In a general office, the requirements for backup power are much lower than in a research building, and are therefore not taken into consideration anymore.
- As the baseload and peak loads are far lower in this scenario, the expectation was that in this design we may be able to operate the building only on solar and cars (except for maybe the night), scrapping the stationary fuel cell and greatly reduce grid usage.
- Solar system size is greatly reduced, to prevent daily surpluses in the summer. There are still some surpluses but they are used to charge BEVs or BESS. Energy comes primarily from wind. The solar system capacity is now large enough that the system potentially has surpluses. These surpluses are used to charge local BEVs or BESS, if applicable.

For both cases the solar system capacity was reduced to 400 kW in 2025 and 300 kW in 2050.

To explore the idea from the last item in the list above, for the Combined Office case in 2025 we chose to prioritize FCEVs and BEVs over SFC (like in alternative design 2 in the combined STCA case). In 2050 however, the design switches back to the 'regular' priority, for which we will see the cause in Section 4.4.2.

3

Methodology & Data Preparation

The goal of this research is to establish clear guidance on the future role of vehicles with usage of CaPP in an office environment, next to comparing hydrogen-based energy systems vs. electricity based energy systems. In order to investigate this matter, quantitative modelling and experimental simulations were used.

Our objective is to calculate cost of energy systems for different design options. By comparing the total costs for the energy system and the component specific costs, we can report on the feasibility of each system design [109]. Secondly, the design should meet a set of requirements for the properties of the energy system itself. These requirements are mostly the result of the goal to provide adequate energy throughout the simulation.

In this research a case study is chosen to examine these questions. With the intention to make steps toward practical implementations, a realistic set of requirements is created using energy and vehicle data from the Shell STCA building. Furthermore, the case study of a single building helps in considering the practical bounds of the system, not only the energy and cost factors. A simulation model is proposed to calculate the energy analysis and system costs. In the following section we discuss all aspects of the model.

3.1. System Analysis

We aim to carry out a techno-economic evaluation that takes into account every aspect of the economics for the system as a whole. A common economic measure to compare different energy sources is the levelized Costs of Electricity (LCOE). In recent years this concept has been expanded to System levelized Costs of Electricity (SLCOE) [109]. But first we have to construct a system that produces adequate energy.

3.1.1. Modelling energy balance

The key values in Table 3.1 or the data prepared serve as a starting point for the STCA fully renewable energy and mobility system. Reiterating the objective, this design is meant to propose a reasonable system fulfilling the needs of local energy demand while simultaneously integrating vehicles in the system and manage renewable intermittency.

Dependent on the scenario, one or two energy carriers with their corresponding components are attainable. In the model procedure we plan for electricity demand initially, then thermal demands and lastly research gas demands. This priority is a progression from large to small energy demands.

Electricity

It was desired to first maximise local energy generation by constructing a solar PV system. This is a logical start because solar is the most cost-efficient way to generate local electricity, providing a direct source of energy [110, 111]. The maximum solar system capacity for this roof area is proposed, yet this is practically never sufficient for the building electricity load. In addition, solar systems do not provide electricity in the night.

The second energy component is modelled after the electricity base load. This energy demand is roughly constant during nighttime (and weekends) operation. The aim is to match the component's capacity to the base load energy consumed over the year and the base load power. This method is discussed in more detail with each separate scenario.

The peak loads are absorbed using the vehicles present at STCA (either employee or visitor parking), using V2G-mode. Depending on the scenario, vehicles can also be charged or fuel from the H_2-grid can be used for this purpose.

Thermal Demands

The case data for the existing heat pump and natural gas flows provide a straightforward basis for the future design. The heat pump system will be kept as is, although it is worth to notice that the installed system has some redundancy. In case we opt for heat pump alternatives, the component's design is equated to the maximum needed capacity in kW_{heat}. The natural gas used for heating purposes such as moisturization and kitchen is replaced by direct H_2 gas. It is assumed that the same energy content is sufficient for this replacement. Analogue to the other direct gas use, the research gas is also replaced by Hydrogen.

The proposed designs in this research serve as experiments, and are not necessarily optimized for construction in practical cases. Instead, the designs provide us with insight in the behaviour of a local system with different topologies, and consequently provides guidance in a broader perspective for future system designs. A 1-on-1 direct comparison of results across scenarios should be done with some careful considerations, as the approach slightly differs for each case. This varying approach was necessary because valid assumptions in one scenario occasionally go against common sense in the other. The most important example of this is the priority of use of production units.

With increasing levels of renewable energy generation, issues like intermittency, energy storage and overproduction become particularly relevant, which are also referred to as 'integration costs'. In the definition of SLCOE integration costs are considered by evaluating the costs of maintaining the system as a whole. Prior research showed that in the energy transition SLCOE becomes vital when investigating financial attractiveness, see [9, 112–114].

It is important to note in this research that we are evaluating costs. Only evaluating costs mean that we are not including overhead costs and profit margins where we can. Our aim is to grasp the actual investment and operational costs per year so that results are general and can be compared.

The general and most simple formula for LCOE is given in Eq. 3.1.

$$LCOE = \frac{TC}{E_T} \tag{3.1}$$

where TC is the total costs over the useful life and E_T is the total energy generated in the useful life. This definition is too broad, therefore the following section breaks it down and adds the necessary complexity for usability.

3.1.2. System Levelized Cost of Energy

This section acts as a reference for the usage of equations by the model for cost calculations. The end goal is to calculate the costs of energy for the system as a whole. The final parameters that we want to derive are the Total System Costs of Energy for STCA ($TSCoE_{STCA}$) and the System levelized Costs of Energy for STCA ($\mathrm{SLCOE_{STCA}}$). These costs are formed from a combination of the components mentioned above. To understand how and which components are used please read Chapter 2.

For the upcoming equations many similar variable names are used and therefore a short repitition of nomenclature is done to provide clarity on the equations was written to guide the following section:

- (S)LCoE = System levelized Cost of Energy (€/kWh)
- TSCoE = Total System Cost of Energy (€)
- subscript *STCA* = The total case (Shell Technology Centre Amsterdam)
- subscript *e* = electrical energy (kWh)
- subscript *h2* = hydrogen (kg)
- subscript *Q* = heat (kWh)

The Total System Cost of Energy (TSCoE)

The $TSCoE_{STCA}$ is the parameter used to compare all the costs associated with the complete energy system on an annual basis. It is the sum of the Total annual capital and maintenance Costs, TC_i (€/year) of the total number of components n in the energy system, where i refers to the i-th component. All energy components in the design are included, such as solar, heat pump or wind turbine.

$$\mathrm{TSCoE_{STCA}} = \sum_{i=1}^{n} \mathrm{TC}_i \qquad [€] \tag{3.2}$$

The TC_i consists of the annual Capital Cost, CC_i (€/year) and the annual Operation and Maintenance Cost, OMC_i (€/year):

$$\mathrm{TC}_i = \mathrm{CC}_i + \mathrm{OMC}_i \tag{3.3}$$

The CC_i consists of three components, namely the Annuity Factor, AF_i (%) ([115, 116]), the installed component capacity, Q_i (component specific capacity), and the Investment Cost, IC_i (€ per specific component capacity),

$$\mathrm{CC}_i = \mathrm{AF}_i \cdot \mathrm{Q}_i \cdot \mathrm{IC}_i \tag{3.4}$$

The AF_i is used to allocate the CC_i over the lifetime of a system. It is based on the weighted average cost of capital (WACC) (%) and the economic lifetime of a component, LT_i (years):

$$AF_i = \frac{\text{WACC} \cdot (1 + \text{WACC})^{\text{LT}_i}}{-1 + (1 + \text{WACC})^{\text{LT}_i}} \tag{3.5}$$

The second component in Eq. (3.3), the OMC_i, is expressed as an annual percentage, OM_i (%), of the installed component capacity, Q_i (component specific capacity) and the Investment Cost, IC_i (€ per specific component capacity):

$$\text{OMC}_i = \text{OM}_i \cdot \text{Q}_i \cdot \text{IC}_i \tag{3.6}$$

The complete cost analysis is performed in constant 2017 euros with a EUR-USD exchange rate of 0.88. The $WACC$ is determined at 3% [115, 116].

Levelized Cost of Energy for any component ($\text{LCoE}_{\text{e,i}}$)

The Levelized Cost of Energy for a component i, $LCoE_{\text{e,i}}$ (€/kWh), is calculated by dividing the Total annual capital and operation and maintenance Costs of the component system, TC_{i} (€/year), by the annual Energy Production of the component, $EP_{\text{e,i}}$ (kWh/year):

$$\text{LCoE}_{\text{e,i}} = \frac{\text{TC}_\text{i}}{\text{EP}_{\text{e,i}}} \qquad [€/\text{kWh}] \tag{3.7}$$

System Levelized Cost of Energy for electricity in the STCA system ($\text{SLCoE}_{\text{e,STCA}}$)

The total system levelised cost is calculated in 3.8. $\text{EC}_{\text{e,STCA}}$ is the total energy consumed at the building (or total electricity demand) and in the numerator we just sum all costs made by each component that is generating this electricity demand. Note that we do not need to include the full chain, only components that are connected directly to the STCA energy demand. Costs made earlier in the system are incorporated in the SLCoE of those components.

$$\text{SLCoE}_{\text{STCA}} = \frac{\sum_{i=1}^{n} \text{(S)LCoE}_i \cdot \text{EP}_i}{\text{EC}_{\text{STCA}}} \qquad [€/\text{kWh}] \tag{3.8}$$

where EC_{STCA} is the total final amount of energy consumed:

$$\text{EC}_{\text{STCA}} = EC_{\text{e,STCA}} + EC_{\text{q,STCA}} + EC_{\text{h2,STCA}} \qquad [\text{kWh}] \tag{3.9}$$

Three energy flows are summed to reach the total energy consumed: electricity, thermal demands, and gas demands. The System Levelized Cost of Energy, $\text{SLCoE}_{\text{STCA}}$ (€/kWh), includes all the cost associated with the electricity supply to the building at all moments, so all storage and balancing cost are taken into account.

3.1.3. Hydro-Electric equations

Levelized Cost of Energy for solar electricity ($\text{LCoE}_{\text{e,Solar}}$)

The Levelized Cost of Energy for solar electricity, $LCoE_{\text{e,Solar}}$ (€/kWh), is calculated by dividing the Total annual capital and operation and maintenance Costs of the solar PV system, TC_{Solar} (€/year), by the annual Energy Production of solar electricity by this system, $EP_{\text{e,Solar}}$ (kWh/year):

$$\text{LCoE}_{\text{e,Solar}} = \frac{\text{TC}_{\text{Solar}}}{\text{EP}_{\text{e,Solar}}} \qquad [€/\text{kWh}] \tag{3.10}$$

Levelized Cost of Energy for wind electricity ($\text{LCoE}_{\text{e,Wind}}$)

The Levelized Cost of Energy for wind electricity, $LCoE_{\text{e,Wind}}$ (€/kWh), is calculated by dividing the Total annual capital and operation and maintenance Costs of the wind electricity system, TC_{Wind} (€/year), by the annual Energy Production that is allocated to go to the electricity grid. $EP_{\text{e,WindGrid}}$ (kWh/year).

$$\text{LCoE}_{\text{e,Wind}} = \frac{\text{TC}_{\text{Wind}}}{\text{EP}_{\text{e,WindGrid}}} \qquad [€/\text{kWh}] \tag{3.11}$$

Levelised Cost of Energy for stationary fuel cell electricity ($LCoE_{\text{e,SFC}}$)

The stationary fuel cell (FC) is also used as a means of electricity production at the office. In order to calculate the Levelized Cost of Energy of the stationary FC system, $LCoE_{\text{e,SFC}}$ (€/kWh), the Total annual capital and operation and maintenance Costs of the stationary FC system, TC_{SFC} (€/year), is divided by the total Energy Production by the stationary FC system, $EP_{\text{Total,SFC}}$ (kWh/year). This total energy production consist of the annual production of heat and power.

$$\text{LCoE}_{e,\text{SFC}} = \frac{\text{TC}_{\text{SFC}}}{\text{EP}_{\text{Total,SFC}}}. \tag{3.12}$$

Levelized Cost of Energy for hydrogen from wind electricity (fed into H-Grid) ($\text{LCoE}_{\text{H,grid}}$)

Besides the cost for the production of electricity, the Levelized Cost of Energy for hydrogen from the hydrogen grid, $LCoE_{\text{H}}$ (€/kg H2), also include the Total annual capital and operation and maintenance Costs (TC) of the water purification system and the TC of the pure water storage tank, $\text{TC}_{\text{watertreatment}}$ and the compressor $\text{TC}_{\text{compressor}}$ (€/year), the TC of the hydrogen production and purification by the electrolyser system, $TC_{\text{electrolyser}}$ (€/year). These added costs are all included in the Total annual capital and operation and maintenance Costs of the hydrogen production infrastructure in the hydrogen grid, $TC_{\text{H,grid,prod}}$ (€/year):

$$\text{TC}_{\text{H,grid,prod}} = \text{TC}_{\text{Watertreatment}} + \text{TC}_{\text{compressor}} + \text{TC}_{\text{electrolyser}} \tag{3.13}$$

All these cost are related to the wind park where the hydrogen is produced. The Levelized Cost of Energy for hydrogen bought from the grid and produced from wind electricity, $LCoE_{\text{H2}}$ (€/kg) H_2), is calculated by allocating the Total annual capital and operation and maintenance Costs of the wind turbines, TC_{Wind} (€/year), that is related to the production of electricity for hydrogen. These costs are combined with the $\text{TC}_{\text{H,grid,prod}}$ from Eq. (3.13). The total cost are then divided by the annual Energy Production of hydrogen bought from the grid, $\text{EP}_{\text{H,grid}}$ (kg H2/year):

$$\mathrm{LCoE}_{\mathrm{H2}} = \frac{\frac{\mathrm{EP}_{\mathrm{used}}}{\mathrm{EP}_{\mathrm{total,Wind}}} \cdot \mathrm{TC}_{\mathrm{Wind}} + \mathrm{TC}_{\mathrm{H,grid,prod}}}{\mathrm{EP}_{\mathrm{H,grid}}} \tag{3.14}$$

System Levelized Cost of Energy for hydrogen from wind electricity (fed into H-Grid) ($\mathrm{LCoE}_{\mathrm{H2}}$)

Analogue to the SLCOE for electricity, we add an additional costs for the hydrogen infrastructure and for hydrogen also large-scale storage. Here we have the hydrogen grid infrastructure costs $\mathrm{TC}_{\mathrm{H,grid,infra}}$ and the hydrogen storage costs, the salt caverns $\mathrm{TC}_{\mathrm{H,grid,store}}$.

$$\mathrm{SLCoE}_{\mathrm{H2}} = \mathrm{LCoE}_{\mathrm{H2}} + \frac{\mathrm{TC}_{\mathrm{H,grid,infra}} + \mathrm{TC}_{\mathrm{H,grid,store}}}{\mathrm{EP}_{\mathrm{H,grid}}} \tag{3.15}$$

System Levelized Cost of Energy for electricity from FCEVs ($\mathrm{SLCoE}_{\mathrm{FCEV}}$)

The grid hydrogen in the system is distributed to the FCEVs in the office car park, which convert it to electricity for balancing the energy system. The cost of the electricity production via this route is given by the $\mathrm{SLCoE}_{\mathrm{FCEV}}$ and it depends on the System Levelized Cost of Energy for hydrogen from wind electricity, $\mathrm{SLCoE}_{\mathrm{H2}}$ (€/kg H2), the Tank to Wheel efficiency of the FCEVs, η_{TTW} (%), the HHV of hydrogen, $\mathrm{HHV}_{\mathrm{H_2}}$ (kWh/kg H_2), the Total annual capital and operation and maintenance Costs of the V2G infrastructure, $\mathrm{TC}_{\mathrm{V2Ginfra}}$ (€/year), and the Total annual capital and operation and maintenance Costs for the replacement of the fuel cell systems in the FCEVs, $\mathrm{TC}_{\mathrm{FC\ System}}$ (€/year).

$$\mathrm{SLCoE}_{\mathrm{FCEV}} = \frac{\mathrm{SLCoE}_{\mathrm{H,grid}}}{\mathrm{HHV}_{\mathrm{H_2}} \cdot \eta_{\mathrm{TTW}}} + \frac{\mathrm{TC}_{\mathrm{V2Ginfra}} + \mathrm{TC}_{\mathrm{FC\ System}}}{\mathrm{EP}_{\mathrm{e,FCEV}}}. \tag{3.16}$$

3.1.4. All-Electric equations

The all-electric scenario uses some of the same equations as used in the hydro-electric scenario, for solar and wind electricity (Eq. 3.10 3.11

Electricity from the (Stationary) Battery Energy Storage System(BESS)

The BESS is charged by the wind electricity from the grid, and then discharged when required. Here we use the $\mathrm{SLCoE}_{\mathrm{e,Wind}}$ as the energy that is converted by BESS and $\eta_{\mathrm{BESScycle}}$ for the roundtrip efficiency (after charge and discharge). Additionally, the total costs of BESS ($\mathrm{TC}_{\mathrm{BESS}}$) divided by the total energy produced ($\mathrm{EP}_{\mathrm{e,BESS}}$) is added. Thus, the equation is as follows:

$$\mathrm{SLCoE}_{\mathrm{e,BESS}} = \frac{\mathrm{SLCoE}_{\mathrm{e,Wind}}}{\eta_{\mathrm{BESScycle}}} + \frac{\mathrm{TC}_{\mathrm{BESS}}}{\mathrm{EP}_{\mathrm{e,BESS}}} \tag{3.17}$$

$$\mathrm{SLCoE}_{\mathrm{e,BESS}} = \frac{\mathrm{SLCoE}_{\mathrm{e,Wind}}}{\eta_{\mathrm{BESScycle}}} + \frac{\mathrm{TC}_{\mathrm{BESS}} + \frac{\mathrm{SLCoE}_{\mathrm{e,Wind}}}{\eta_{\mathrm{BESScharge}}} \cdot \mathrm{ES}_{\mathrm{e,Stored}}}{\mathrm{EP}_{\mathrm{e,BESS}}} \tag{3.18}$$

Electricity from BEVs

The BEVs are calculated in a similar way to the BESS but an extra component is added to charge and discharge the vehicles, the bidirectional chargers. The BEVs are charged by the wind electricity from the grid, and then discharged when required. Here we use the $\text{SLCoE}_{\text{e,Wind}}$ as the energy that is converted by BESS and η_{BEVcycle} for the roundtrip efficiency (after charge and discharge). Additionally, the total costs of BEV battery replacements (TC_{BEV}) plus the total costs for the bi-directional chargers $\text{TC}_{\text{bd-chargers}}$are divided by the total energy produced ($\text{EP}_{\text{e,BEV}}$) is added. Thus, the equation is as follows:

$$\text{SLCoE}_{\text{e,BEV}} = \frac{\text{SLCoE}_{\text{e,Wind}}}{\eta_{\text{BEVcycle}}} + \frac{\text{TC}_{\text{BEV}} + \text{TC}_{\text{bd-chargers}}}{\text{EP}_{\text{e,BEV}}} \tag{3.19}$$

System Levelized Cost of Energy for wind electricity ($\text{SLCoE}_{\text{e,Wind}}$)

The term 'system' is added to the Levelized Cost of Energy for wind electricity to indicate that the cost of the electricity grid is also taken into account. The System Levelized Cost of Energy for wind electricity, $SLCoE_{\text{e,Wind}}$ (€/kWh), is calculated by dividing the Total annual capital and operation and maintenance Costs of the wind turbines, TC_{Wind} (€/year), with the Total annual Costs of the electricity grid, $\text{TC}_{\text{e,Grid}}$ (€/year), and adding the costs made for surpluses that needed to be stored externally, $\text{TC}_{\text{GridStorage}}$. This is divided by the annual Energy Production (bought from the grid in this case) of wind electricity by the wind turbines, $\text{EP}_{\text{e,Wind}}$ (kWh/year):

$$\text{SLCoE}_{\text{e,Wind}} = \frac{\text{TC}_{\text{Wind}} + TC_{\text{e,GridStorage}}\text{TC}_{\text{e,Grid}}}{\text{EP}_{\text{e,Wind}}}. \tag{3.20}$$

Electricity from FCEVs

It is important to notice in this equation that for the hydrogen price in this all-electric case the hydrogen market price is taken. For the rest it is similar to the other equations as BESS and BEV.

$$\text{SLCoE}_{\text{e,FCEV}} = \frac{\text{C}_{\text{H,Market}}}{\eta_{\text{V2G}} \cdot \text{HHV}_{\text{H2}}} + \frac{\text{TC}_{\text{FCEV}} + \text{TC}_{\text{discharge}}}{\text{EP}_{\text{e,FCEV}}} \tag{3.21}$$

Market prices for Hydrogen and Electricity

For the alternative design in the all-electric case, we need the following equation: For balancing electricity, electric energy is exchanged with the electricity market. A fixed price is assumed for buying and selling on the market. For selling, the value is chosen to be 0 at this moment (same as excess energy discarding). For buying a fixed value is chosen at 0.07 € / kWh. This has to be incorporated in the total equation with $\text{C}_{\text{e,Market}}$, the costs per kWh and $\text{EC}_{\text{e,Market}}$ the total energy bought and consumed from the market.

System Levelized Cost of Energy for electricity in the STCA system ($\text{SLCoE}_{\text{e,STCA}}$)

The electricity for the office building is supplied in four ways, namely the direct use of solar electricity, $\text{EP}_{\text{e,Solar}}$ (kWh/year), direct electricity from electricity grid (wind) $\text{EP}_{\text{e,WindGrid}}$ (kWh/year), electricity from BEVs in V2G mode, $\text{EC}_{\text{e,BEV}}$ (kWh/year), electricity from the conversion of hydrogen from FCEVs, $\text{EP}_{\text{e,FCEV}}$ (kWh/year) and electricity bought from the electricity market, $\text{EC}_{\text{e,Market}}$. The System Levelized Cost of Energy for electricity in STCA, $\text{SLCoE}_{\text{e,STCA}}$ is determined by taking the weighted average of the cost associated with each of these electricity supply routes:

$$\mathrm{SLCoE_{e,STCA}} = \frac{\mathrm{LCoE_{e,Solar} \cdot EP_{e,Solar} + SLCoE_{e,Wind} \cdot EC_{e,DirectGrid}}}{\mathrm{EP_{e,Solar} + EC_{e,DirectGrid} + EP_{e,BEV} + EP_{e,BESS} + EP_{e,FCEV} + EC_{e,Market}}} + \frac{\mathrm{SLCoE_{e,BEV} \cdot EP_{e,BEV} + SLCoE_{e,BESS} \cdot EP_{e,BESS} + SLCoE_{e,FCEV} \cdot EP_{e,FCEV} + C_{e,Market} \cdot EC_{e,Market}}}{\mathrm{EP_{e,Solar} + EC_{e,DirectGrid} + EP_{e,BEV} + EP_{e,BESS} + EP_{e,FCEV} + EC_{e,Market} + EC_{e,MarketSold}}} \tag{3.22}$$

The System Levelized Cost of Energy for electricity in the STCA system, $\mathrm{SLCoE_{e,STCA}}$ (€/kWh), includes all the cost associated with the electricity supply to the building at all moments, so all storage and balancing cost are taken into account.

System Levelized Cost of Energy for Hydrogen in the STCA system $\mathrm{SLCoE_{H,STCA}}$)

As there is only one component that uses H_2 in this case, the following is valid:

$$SLCoE_{\mathrm{H,STCA}} = SLCoE_{\mathrm{H,Grid}} \tag{3.23}$$

System Levelized Cost of Thermal Energy in the STCA system

Thermal demand can be separated into two equations, one for the direct use of H_2 by the incinerator, the other for the thermal demand of the office by the heat pump and moisturization and kitchen $\mathrm{EC_{e,Auxiliary}}$.

$$\mathrm{SLCoH_{Q,Lab}} = \frac{\mathrm{SLCoE_{H,Grid}}}{\mathrm{HHV_{H2}}} \tag{3.24}$$

$$\mathrm{SLCoH_{Q,Office}} = \frac{\mathrm{SLCoE_{e,STCA} \cdot (EC_{e,HeatPump} + EC_{e,Auxiliary}) + TC_{HeatPump}}}{\mathrm{EC_{e,HeatPump} + EC_{e,Auxiliary}}} \tag{3.25}$$

Specific Cost of Energy for the office building ($\mathrm{SCoE_B}$)

The cost associated with the energy consumption of the office are expressed in the Specific Cost of Energy for the office building, $\mathrm{SCo_{EB}}$ (€/m^2·year),

$$\mathrm{SCoE_B} = \mathrm{SLCoE_e \cdot SEC_B} \tag{3.26}$$

The Specific Energy Consumption of the office building, $\mathrm{SEC_B}$ (kWh/m^2·year), consists of the office total electricity demand divided by the office floor area. The system levelized cost of energy for electricity of the office energy system is obtained from

$$\mathrm{SLCoE_e} = \frac{\mathrm{TSCoE_{office,e}}}{\mathrm{EC_e}} \tag{3.27}$$

where $\mathrm{EC_e}$ is the annual Electricity Consumption (kWh/year).

3.1.5. Sensitivity Analysis

As we are discussing future developments of components and many of the parameters rely on predictions, it was decided to carry out a sensitivity analysis. This analysis enables us to dive deeper into the influence of specific parameters on the end results, by altering their values and running the model again. For the Mid Century scenario the parameters contain a higher level of uncertainty. A sensitivity analysis was targeted at the impact of parameters on $\mathrm{SLCoE_{STCA}}$. The parameters were selected if they generally satisfied one or more of the the following requirements:

1. The parameter value chosen is uncertain and future developments could cause a significant deviation from the baseline value.

2. The parameter is suspected to have a large impact on the end result ($SLCoE_{STCA}$ or TSC_{STCA}).

3. The parameter is **not** a design parameter, meaning that it could be freely designed within the model, such as component sizes or utilization rate.

Requirement 3 had been chosen because many different combinations of these parameters had been simulated already during the system design phase in order to reach the final designs. It is important to note though that these parameters often do have large impact on the end result and are equally or more important. Not every parameter was tested for every scenario, only for 2050 the Hydro-Electric and All-Electric extreme cases are analysed, including both the STCA and Office case. The combined case was excluded, because we assumed the results would be similar or less impactful, since it has a more even distribution of component costs. Typically, the Investment Cost (IC) parameter of each component was substituted for either a 10% higher or lower cost.

3.2. Model formulation

This thesis builds on prior research and methodology developed by the TU Delft Future Energy Systems research group [54, 58]. In the introduction I mentioned modelling case studies and experimental research on the CaPP concept that is now applied to a real-life case study with more specific and accurate data. The preparation of the model and its parameters was divided in separate tasks:

1. Identifying case study and data sources, preparing data for modelling and setting up model requirements. Define model input and output parameters and set up research assumptions. Determine equations that model the energy system and calculate the techno-economic output parameters. (Chapter 2, Section 3.1.1 of this thesis)

2. Review components for use in the energy system model. Operating from the component function requirements defined in 1. we look at different technology options to fulfil a functionality in the energy system. I review technologies on their role in (local) energy systems and determine economic and technical parameters including costs, efficiencies and sizes (Chapter **??**).

3. Select sets of components for the scenarios to simulate and integrate them into a model of the STCA or office energy system. Simulate and explore different designs within different component constraints and selections. Evaluate designs with an energy analysis and a techno-economic analysis. (Chapter 4)

3.2.1. Model development

This model has been developed in MATLAB and studies of [56, 57] were used as a base for the modelling process. The following principles were being adhered to during the modelling, to maintain the right level of complexity:

- The focus lies on the techno-economic analysis, not on modelling the actual physics. Instead, the aim is to capture components' physical behaviour by simplifications that still reasonably represent real physics. As we simulate a full year in 15-minute timesteps, the computing time should also be feasible.

- Modelling is done from the demand side of the energy system. So starting with the electricity load, heat demand etc. the model calculates and sizes the components behaviour. This enables the model to calculate some design choices itself.

- Start-to-end supply chain of energy. The boundary of the model starts at the wind and solar power converted by the components. From there, the full supply chain of energy is taken into account, including storage necessities, seasonal and daily, transport infrastructure, thermal demand, electricity demand and other end uses. Design external of STCA is regarded as part of a larger open system, of which the necessary capacity is bought. Outside STCA however we only model and account for precisely the capacity that we need, obtained from a larger national system.

- Design within STCA is seen as its own. Here, at STCA we only buy full components that could actually exist and be installed / designed.

- We have a closed system where we have to deal with the intermittency of wind and solar energy ourselves.

This research design is meant to portray the future trend of decentralized energy hubs, where self-sufficiency is preferred if possible. The approach has a limitation though that should be highlighted: the model represents a closed energy balancing system, whereas in reality the external parts of the system are in part of a much larger national system. This was done to enable us to evaluate direct influence of energy supply intermittency and storage necessity for a local system. The system in the model is still connected to the larger national system but it is not considering what happens in the open national system.

3.2.2. General Simulation steps

1. On a 15-minute timestep interval, simulate energy demand flows for one year.

2. Dimensioning of wind turbine according to wind profile and total energy requirements. After subtracting the local solar system.

3. Set up a priority of dispatch for components along the intentions of the scenario. (shown in e.g. Sec. 2.3.2 Fig. 2.5)

4. For every timestep, solve the energy equation by balancing the demand with the generating components.

5. If there is a wind surplus or a supply deficit, use the external storage component to solve this mismatch.

6. Achieve energy balance for every timestep and for the full year in total.

7. Calculate costs with the now determined component usage and size by system costs analysis (see 3.1)

3.3. Data preparation

Most Data originated from a case study: the Shell STCA building. This data represents a unique combination of research and office energy usage. This is largely demonstrated by the significantly higher energy consumption, on every facet (gas use, electricity, heating).

It is especially relevant in the regard of a future energy system that we obtain information on *when* energy is available or required. Additionally, the energy profile is linked to some social aspects: The energy consumption is naturally lower during non-business hours, as is the amount of cars in the parking lot.

We can divide the energy profiles into three main streams on the consumption side: Electricity demand, Heat (and cool) demand and gas demand. Above, the heat and cool demand is already discussed. In this particular research also the PV System data and the electric vehicles are present as energy generators. These are assumed to be the same for the office and STCA case.

Site data was directly available and most has been used as a direct input for the model or with some slight adaptations. Below a list of the most important data sources that were used and if any adaptations were made:

- 15 minute interval electricity meter data of STCA of the year 2017. This dataset served as a baseline for the electricity demand, but as it was from the electricity meter some small adapations needed to be made. The existing solar system production was added to this data to reach the real electricity demand. Also, as we wanted to separate electrical loads and heat demand, I subtracted the heat pump electricity.

- Existing solar energy system production for part of 2017. This was extrapolated with irradiation data.

- Heat pump electricity demand hourly energy consumption. One week for every month. To reach a dataset for a full year I made a regression model with temperature data from KNMI in Amsterdam. This, however did not yield the real heat and cooling demand yet (only the electricity consumption). For the demand, only total monthly values heat and cool demand were available. From this, we could calculate a monthly coefficient of performance (CoP). Then, by applying this CoP together with the monthly cool/heat ratio the heat and cool demand could be estimated.

- Deltares wind speed data from Borssele IV wind site off-shore of 2011 (most recent year). Hourly wind speed.

- Solar irradiation data of KNMI of Schiphol (closest to amsterdam office). To calculate new solar system.

- Hourly total gas consumption of STCA. This data is separated by a proportion that was giving yearly totals of research/office ratio. (30 mbar / 300mbar).

- Parking garage data for the first two weeks of 2018. This data was extrapolated to a full year. An early realisation showed that only a handful of cars would be available outside office hours. The building itself having a significantly higher baseload, it was decided to assume that the parking garage was also partly utilized by other parties in the neighbourhood outside of office hours.

- To estimate the state of charge (SoC) or fuel tank level of arriving cars, an average commute distance for the Netherlands was used, which is about 30 km. Then we apply a random distribution to how many times this distance was driven by the car and had no charging since.
- A literature review was done to obtain all component economic and efficiency parameters.

3.3.1. STCA

Electricity load

The electricity profile is calculated by looking at the electricity meter data, the PV data and the WKO data. The result is the following:

$$E_{el} = E_{meter} + E_{PV} - E_{WKO} \tag{3.28}$$

24 000 kWh of backup power is required, and a capacity of approximately 1 MW. This is currently divided up into two diesel generator systems.

Thermal energy profile

Having available the hourly electricity consumption data from the heat pump and the monthly heat and cool demand, it was possible to reproduce an estimated heating and cooling profile per hour.

The following method was chosen: Starting by calculating a monthly COP with the total demand and input per month. Because of the incomplete data I assumed that the cooling efficiency and heating efficiency (COP) are identical. This is fair because of multiple reasons: In most months the COP is influenced heavily by only one of the processes, therefore the effect is minimal. Additionally, literature suggests evaluating through the seasonal performance factor (SPF). COP is used in the designs and SPF is more common in measuring the actual performance. Average SPF in installed systems in 2010 was 3.5 [117]. Cooling efficiencies in ground-source heat pumps are generally similar to or better than their heating equivalent [118–121]. We also see this in the months with higher cooling demand, where the COP reaches higher values. Therefore, with the COP table that we have and the scope of this research it is reasonable to assume the same factor to determine heating and cooling demand. It is also assumed that the pattern for cooling and heating is the same, because it is mostly dependent on people entering and leaving the building. Using the monthly heat and cool demand share we can calculate both COP and electricity consumption. With these values we now calculate the hourly heat and cool demand.

Some other methods were tried to see if there were any different results. Using the COP curve given in the data and constructing an estimated COP curve for cooling from literature reached similar results. Therefore, the much more simple method above is preferred.

Use of natural gas

The STCA also has a gas consumption profile which is mainly dependent on the use of an incinerator and moisturizing the office in colder months. Smaller applications are cooking and glasswork (done by the research department).

All of these activities can be replaced by a different heating source like electrification or hydrogen. Cooking can be electrified, and for reaching high temperatures H_2 can be burned in the same way as natural gas for the incinerator and moisturising the air.

At this point, the gas consumption data will be used as a starting point. How the different applications of the gas are dealt with will be further discussed in the design of system.

Secondary Heating: Moisturization and kitchen

Natural gas also serves as a heat source in the kitchen and for moisturization of air for heating purposes. To obtain this, we separated the gas consumption data into two categories: low-pressure (30 mbar) and high pressure (300 mbar). According to the data, the research gas is the high pressure gas, leaving the low-pressure gas for the office purposes. The low-pressure gas is however quite significant and takes up more than 50% of the total gas use, this is why it is suspected that there may be other gas consumers involved which are not meant for the office but research instead. As no clarification was available, it is assumed that all low-pressure gas is meant for office purposes.

In the hydro-electric case, the gas is replaced by the same **hydrogen** energy content. In the all-electric case it is replaced by the same **electricity** energy content.

2050 case

Due to electrification of technologies inside buildings as cooking and heating, the share of electricity in the energy mix is increasing [122]. Research institute CE Delft modelled the transition of the Dutch city of Delft to energy neutrality in 2050 and concluded that electricity consumption in business sectors will remain constant or even increase [123]. Yet there are still improvements possible in energy efficiency of appliances and behavioural changes. The current situation still has economic and social barriers for implementing new technologies and ambiguous policies regarding building energy consumption. For example the Dutch energy label (EPC) does only account for basic functionality of the building like lighting, elevators and heating. No policies have been implemented regarding other appliances. Policy makers have a key role in introducing policies in this regard. Behavioural changes have been overlooked in particular [124, 125]. As implementations of energy efficiency standards in (IT-)appliances and behavioural changes are not accounted for in the current data this research assumes a 10 % electricity consumption reduction for the 2050 case.

For gas use, some applications of the gas use could be electrified as mentioned above. The same reasoning as with the heat and cooling demand and the electricity consumption can be used for the gas consumption. It is also logical to be consistent in the energy reduction, thus a 10 % gas consumption reduction is proposed in this case. With the effects of climate change we would expect that the necessity of heating and cooling also changes. One way to measure this is examining the heating and cooling degree days in a year (HDD & CDD). After picking a base temperature (usually 18 ° C), one counts days with temperature above or below this temperature degree days. Spinoni et al. report that in Europe there will be a small decrease in heating degree-days in the future, but there are no significant changes in cooling degree days [126]. Therefore the cooling demand stays constant throughout both scenarios. For heating the European Commission argues that most of the buildings that are used in 2050 are already existing today. Reduction in heating demand is achieved through renovations and innovations in smart buildings (demand response), electrification and use of waste heat [127]. It is also argued by the

IEA that future buildings should consume 15-30 kWh / m^2 for heating purposes and that a near-Zero Energy Building (nZEB) may consume only 15 kWh / m^2 for heating, cooling and ventilation purposes. [128]. The STCA building is already in that range (29.9 kWh / m^2 for heating and cooling). In a cross-country comparison of modeling heating and cooling demand a 10 % reduction is reached in 2050 [122]. As the current profile is already approaching to 2050's targets and with the other information above, I propose a decrease of 10% in heating demand.

Table 3.1 summarises the key values of the energy profile that guide the system design:

Value	Min	Median	Max	Unit
Electricity Demand				
Power	1454	1916	3463	kW
Daily	37,064	54,867	63,353	kWh
Monthly	1,456	1,576	1,701	MWh
Yearly	-	**19,010**		MWh
Gas Demand				
Hourly	0	27	183	m^3
Daily	48	696	3552	m^3
Monthly	12,430	25,779	67,486	m^3
Yearly	-	**361,329**	-	m^3

Table 3.1: Summarised key values of the energy profile.

3.3.2. Energy profile for average office buildings

For the energy profile of an average office we look at average yearly values for office buildings, and then calculate a ratio comparing it to the data at STCA. Subsequently, this ratio is applied to the existing data patterns already made for STCA. Also, in some cases there was a distinction available in the data, with gas use for example. Highlighted input parameters are listed below:

- A floor area of 50,000 m2 is assumed.
- Electricity: Use the top 20% in energy efficiency of Dutch buildings of 2016 for electricity: 60 kWh/m2 in 2025, 35 kWh/m2 in 2050.
- Thermal demands. 2.2 m3/m2 natural gas use is used as input for heat demand.
- The secondary heating and the cooling purposes are all recalculated by taking a ratio of floor area.

Electricity subdivision within buildings

In office buildings, the electricity consumption can be mainly traced back to lighting (35-39 %) and IT appliances (30%). Other consumers are air-conditioning and ventilation. [129, 130].

Building energy consumption is a difficult topic to study because the values that we are looking for (e.g. energy consumption per square meter) are generally not directly measured. Therefore, most studies conducted are meta-studies investigating large

Source	Mean electricity consumption (kwh/m2/year)
Milieubarometer NL (2014)	86
ECN (2016) (10 – 20 103 m2)	99.1
-	
UCL Energy Institute UK (2013)	121
IEA (2012)	105

databases of regions or states. It is also argued by multiple sources that energy performance standards, design requirements and building designs do not accurately represent the actual energy performance of a building [131–133]. It is therefore desirable to examine multiple sources to reach an accurate value.

The following table lists values found in different sources for the electricity and heat consumption of buildings. The Milieubarometer [134] is used in the Netherlands to benchmark companies and is constructed by an institution that benchmarks utility buildings. The numbers are specifically for offices in the Netherlands but further details are not specified well. It shows a range of the electricity and gas consumption and the mean. For electricity this is 57-110 kWh/m^2 with a mean of 86 kWh and for heating the range lies between 1.4-4.8 m^3 gas/m^3 with a mean of 2.2 m^3 gas/m^3.

2050 office

For 2050 the secondary heating (office gas) component is removed completely, because the usage is very high compared to countrywide averages and did not seem to accurately represent natural gas use in an office environment. Electricity was reduced proportionate to STCA.

4 Results

The results consist of three categories: Energy analysis, economic evaluation and design implications. Design implications are the interpretations of the results per scenario, discussing practical issues and feasibility of the design or other relevant interpretations. First, the two extreme scenarios are compared, then the combined scenario is discussed separately. The office case is evaluated in the same manner as the STCA case. Last, the sensitivity analysis shows which parameters are influential in changing the total system costs.

In the following sections when a graph or table is initially introduced it is explained how it should be read. The explanation includes the intention behind the graph/table, the crucial values to examine and other details for comprehension. Often the same type of diagrams will be repeated for subsequent scenarios and thus no longer explained. At those points I discuss only the main deductions or differences. Also, not every scenario includes every type of diagram because it was not always relevant to show.

4.1. Hydro-Electric vs. All-Electric

Large differences uncover when comparing the results side-by-side. Generally, the hydrogen-based case needs far higher capacities of wind, although it turns out to be more cost-effective in the end.

4.1.1. Energy analysis

In this section we will analyse the behaviour of the energy system in the perspective of energy balancing, losses in the system and component utilization.

Annual energy balance

Starting with the yearly energy balance, in a hydrogen based system we can directly conclude that the amount of energy produced vs. the electricity end use is very large: More than twice as much energy is produced than consumed. Figure 4.1 visualises the annual energy balance plotting energy production vs. consumption. We see that 43.55 GWh is produced while only 22.56 GWh is consumed. This is due to the fact that a hydrogen-based system features higher losses. The energy intensive processes of con-

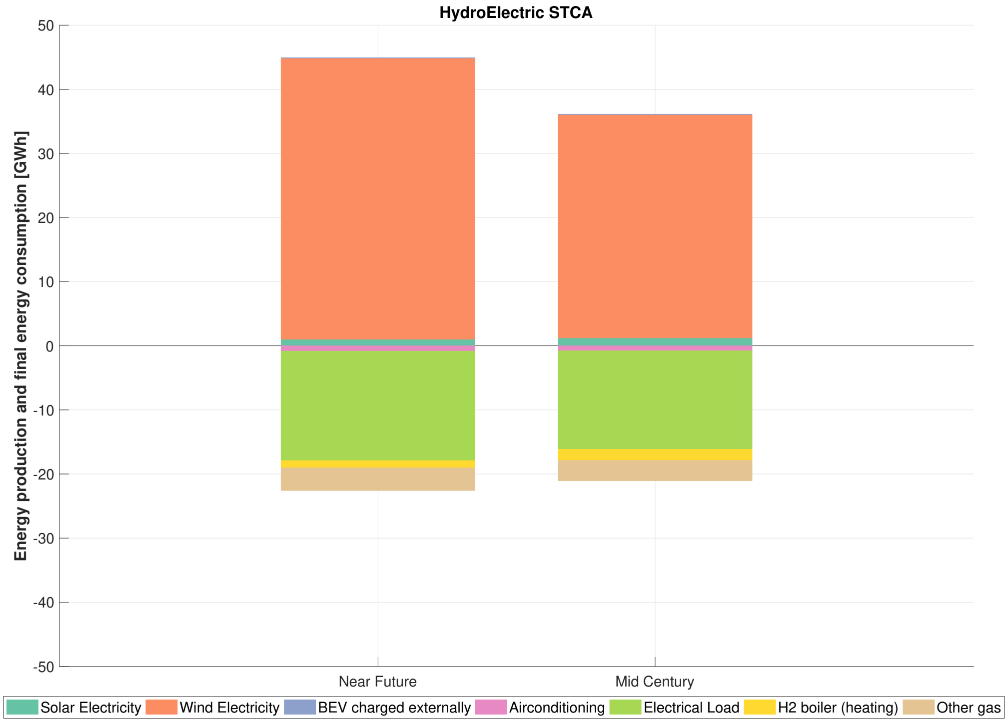


Figure 4.1: **Annual Energy Balance STCA in the Hydro-Electric Case.** Original energy produced is plotted as positive, final energy consumption at STCA plotted as negative values. Hydrogen is converted to kWh with HHV (39.41 kWh/kg)

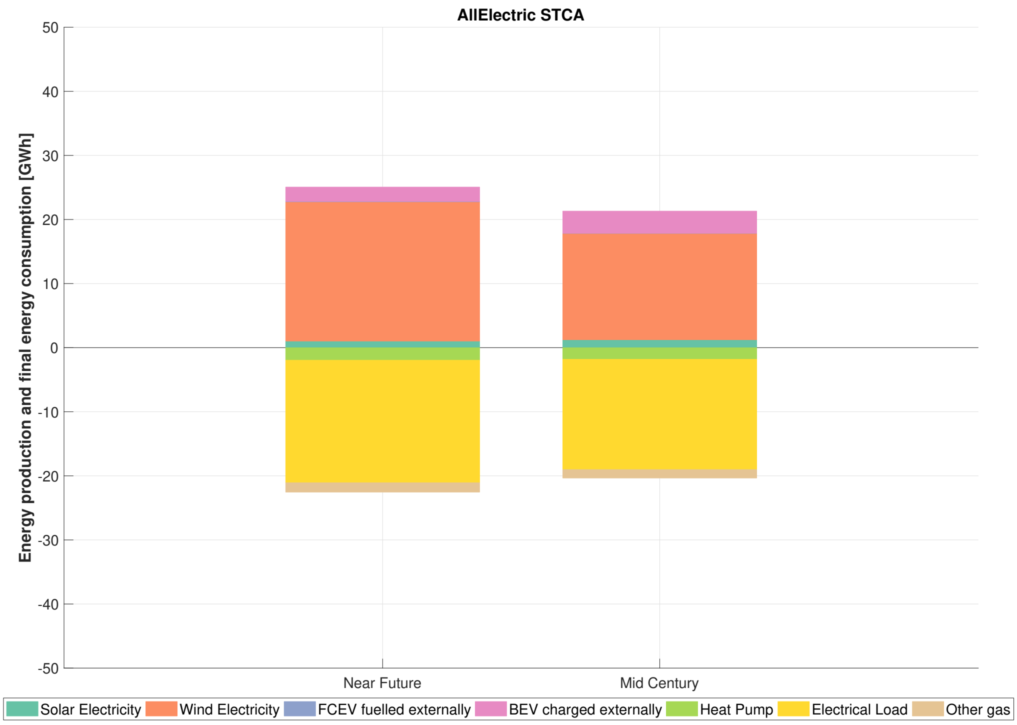


Figure 4.2: **Annual Energy Balance STCA in the All-Electric Case.** Original energy produced is viewed as positive, and final energy consumption at STCA is shown as negative values. Hydrogen demand is converted to kWh with HHV (39.41 kWh/kg)

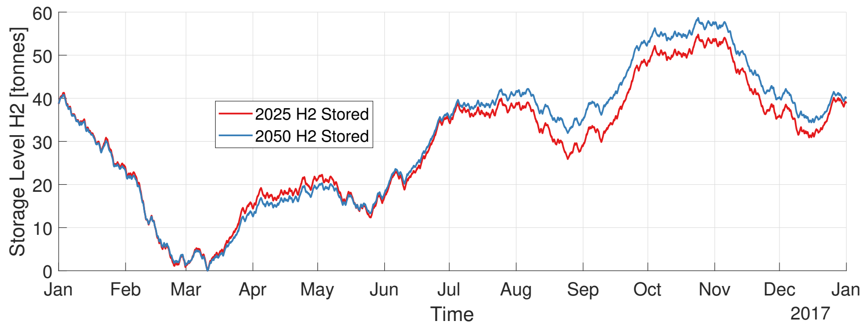


Figure 4.3: **The hydrogen storage level in the external Salt Cavern storage in the Hydro-Electric case.**

verting electricity to H_2 back to electricity are causing this large difference.

The electrical load takes up the major part of the demand side. On the production side, nearly all energy is produced by the wind turbine, solar and BEV contribution are low. BEV is included separately in this graph because the energy produced from BEVs come from an external source, in contrast to FCEVs where H_2 fuel is originally coming from the wind turbine (see Chapter **??** for how this works).

For 2050, the pattern remains similar, although we do see that the energy production reduces more quickly than the demand. This is due to the fact that a number of efficiency improvements are implemented in the future, leading to higher conversion factors. These improvements can be traced back to the electrolyser, SFC and FCEVs.

In the All-Electric design the losses are undoubtedly lower than in the previous scenario, as is portrayed in Fig. 4.2. The wind turbine nevertheless serves as the main electricity source. The consumption side remains similar to the previous case, but not identical since the electricity use is higher due to the heat pump. In 2050 we see that the external BEV contribution becomes considerable: Battery capacities are a lot higher in this year.

Seasonal balance

The salt cavern H_2-levels serve as a massive energy buffer throughout the seasons, as is depicted in Fig. 4.3. This figure is showing the storage levels of the salt cavern throughout the year. Within one year, the maximum difference between storage levels approaches 60,000 kg of Hydrogen. The lowest point is in March, where wind energy has been consistently insufficient for several months. In contrast the wind profile is exceptionally high in October and November leading to a constant energy surplus. Other reasons for the high deficiencies in the first months of the yearare the higher energy demand for heating and obviously the low solar irradiation, although these factors are far less significant than the wind profile. At the end of the year the storage level converges back to the starting value, leading to an approximately balanced system, as was proposed in the design.

Energy Flows

The external hydrogen production and storage chain is where the largest energy flows occur, as can be seen in Fig. 4.4. Fig 4.4-4.7 are Sankey diagram where the thickness of a flow correlates to the amount of energy that goes through it and the connections show where the energy goes.

We can identifiy a definitive 'main' branch in this diagram going from wind electricity to electricity demand. The largest absolute losses are at the electrolysis process, however in relative terms FCEVs have the highest losses. After the conversion to H_2 more than 2/3 is consumed directly and the remainder makes a cycle through the Salt cavern first.

Locally, we see that the SFC is the main contributor to the energy demand, providing the majority of electricity and more than 50% of heat demand. The solar system, FCEV and BEVs have a low contribution to the total energy production. Their importance is however higher than their proportion in this diagram, because they deal with the peak loads.

The key contrast in the comparison is the amount of external storage used in both cases: 32% of produced hydrogen is stored in Salt Caverns in the HE-case while only 17% is stored in external batteries in the AE-case. This is caused by the following factors:

- The level of distributed generation is a lot higher in the AE-case: 4438 MWh originates from external fueling/charging of EVs. At the HE-case this number is negligible since FCEVs are connected to the grid.
- In HE, the SFC has a maximum capacity of 1600 kW. In the AE case it is possible to use higher capacities directly through Direct Grid use, whenever the demand allows this.
- AE-case also uses some electrolysis to cope with gas demands, therefore there is an additional storage component.
- In the All-Electric case the model attempts to charge local components first, and uses the external storage as a secondary option.

Summing all these aspects gives 9009 MWh which is 30% of all wind energy produced.

One noticeable result is the high energy demand for ”Electric Heating” (which is the natural gas energy equivalent for moisturization and kitchen purposes), which is even higher than the total energy demand of the heat pump. This is a data issue and that some of this energy should be allocated to ”research gas” instead. Fig. 4.7 reveals that in Mid-Century scenario the results remain similar. The BEVs however take up a slightly larger proportion, mainly reducing the necessity of using FCEVs.

For the mid-century scenario the annual energy flows do not significantly change, except that the flows decrease due to higher efficiencies (Fig. 4.5). H2 boilers have a higher contribution in this scenario because the SFC collected heat is lower this is due to 1) higher contribution of other components, 2) higher electrical efficiency producing less heat).

As we saw in the previous figures, the SFC is the backbone of he HE system. This is because it is prioritised for dispatch at any electrical demand, after solar. The SFC is operated at nearly constant full capacity, as is illustrated in Fig. 4.8. The utilization rate of the other electrical components is far lower. The solar system utilization rate is however depicted by the irradiation, and not through design choices.

The system practically never uses more than 100 cars (= 1000 kW), but we still see that cars in V2G mode are still used 6000 out of 8760 hours, however for most of the time just a handful are used. In Fig. 4.8 the load duration curves of each local component are shown and we can directly see that the capacity factor of the V2G components are relatively low. This is, of course, a logical result from using them only as a later dispatch

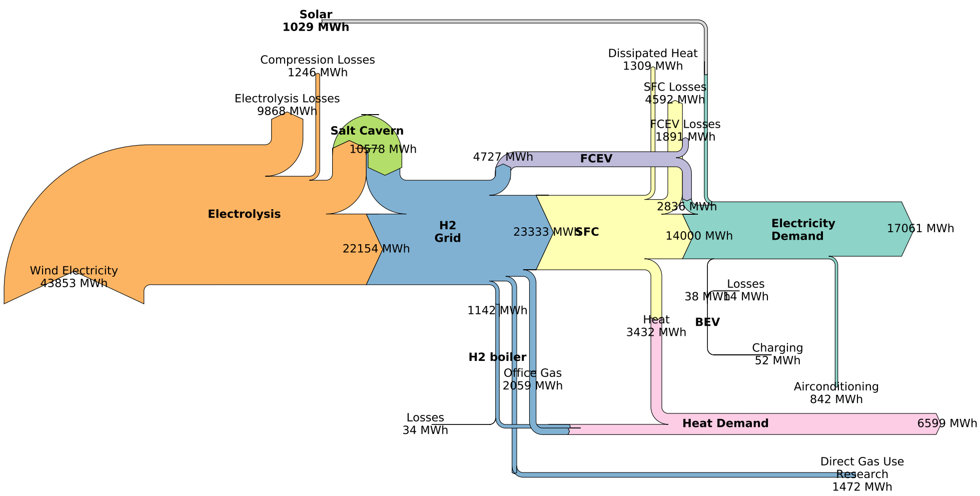


Figure 4.4: **Hydro-Electric STCA 2025 Energy Flow Diagram.** Hydrogen is displayed with by its energy content in HHV (39.41 kWh/kg).

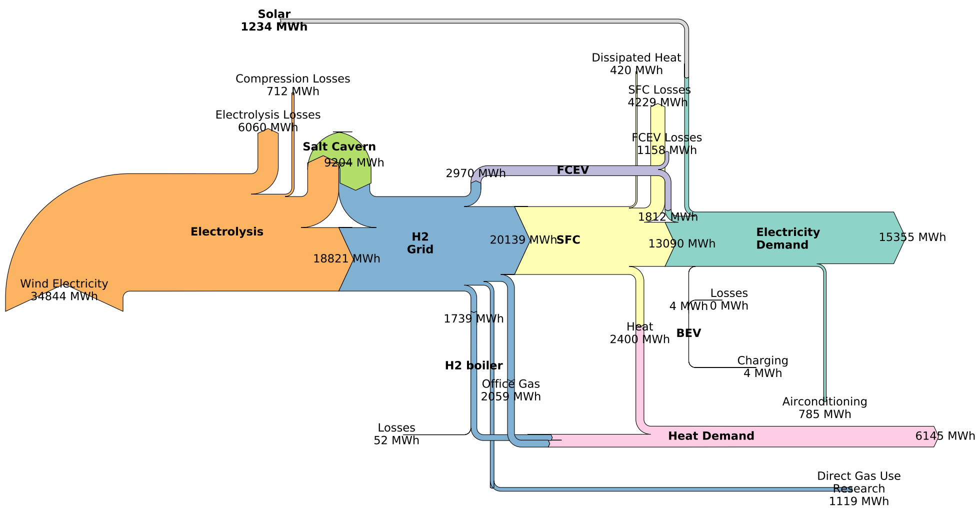


Figure 4.5: **Hydro-Electric STCA 2050 Energy Flow Diagram.** Hydrogen is displayed with its energy content in HHV (39.41 kWh/kg).

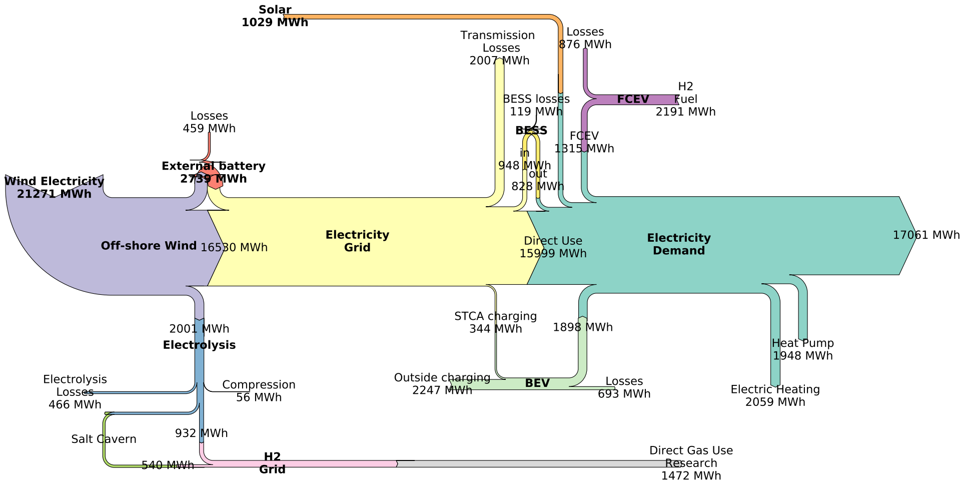


Figure 4.6: **All-Electric STCA 2025 Energy Flow Diagram.** Hydrogen is displayed with by its energy content in HHV (39.41 kWh/kg).

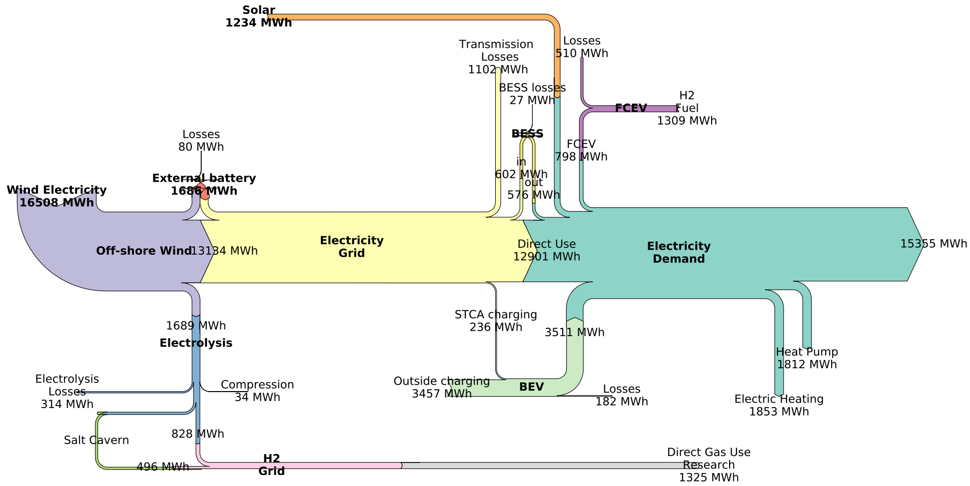


Figure 4.7: **All-Electric STCA 2050 Energy Flow Diagram.** Hydrogen is displayed with by its energy content in HHV (39.41 kWh/kg).

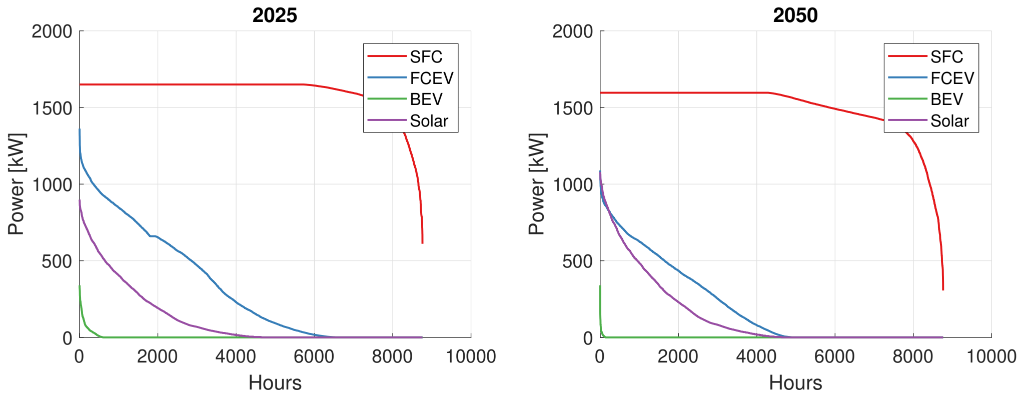


Figure 4.8: **Load Duration Curves (LDC) of Hydro-Electric Scenario in 2025 (left) and 2050 (right).** The graph shows how many hours a component is used (x-axis) at a certain power level (y-axis). The area underneath is equivalent to the total energy production of that component per year.

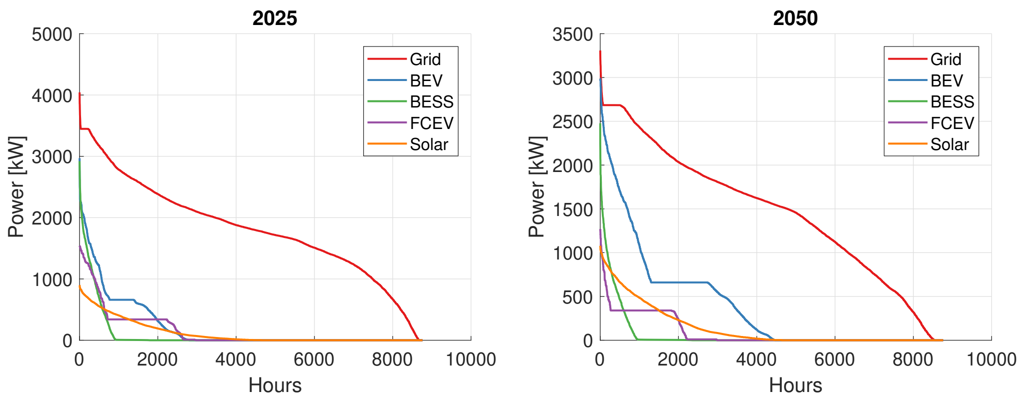


Figure 4.9: **Load Duration Curves (LDC) of Hydro-Electric Scenario in 2025 (left) and 2050 (right).** The graph shows how many hours a component is used (x-axis) at a certain power level (y-axis). The area underneath is equivalent to the total energy production of that component per year.

during peak loads. In the 2050 case the utilization of BEVs is negligible. In the economic section (4.1.2) we will see that this capacity factor is a large determinant in cost.

The priority of use can be nearly directly derived from Fig. 4.8, as well as the total capacity. Solar energy is a small exception here, but the solar energy production is dependent on the solar irradiation and therefore capacity factors are lower.

In 4.9 the plotlines for BEVs and FCEVs plateau at certain points. These correspond to weekend and nighttimes, when the car park is occupied by only 100 cars. 66% is BEVs and 33% are FCEVs and these periods show that the model used the maximum amount of cars available.

Weekly energy profile

Now that we are aware of the gross energy flows of this system it is worth explaining these results by zooming in on the weekly profile. Fig. 4.10 displays the representative weeks of one month in each season We see that for electricity, the power demand increases in the summer, because of the usage of the air-condidtioning system. As H_2 is used for heating in this case, the heightened total energy demand in colder months cannot be seen in these plots. The SFC is nearly always operating at full capacity, as it is designed to cover the baseload. Only in weekends with high solar irradiation the SFC Power is lower. Peak loads during office hours are covered by FCEVs (between 1650 and 3000

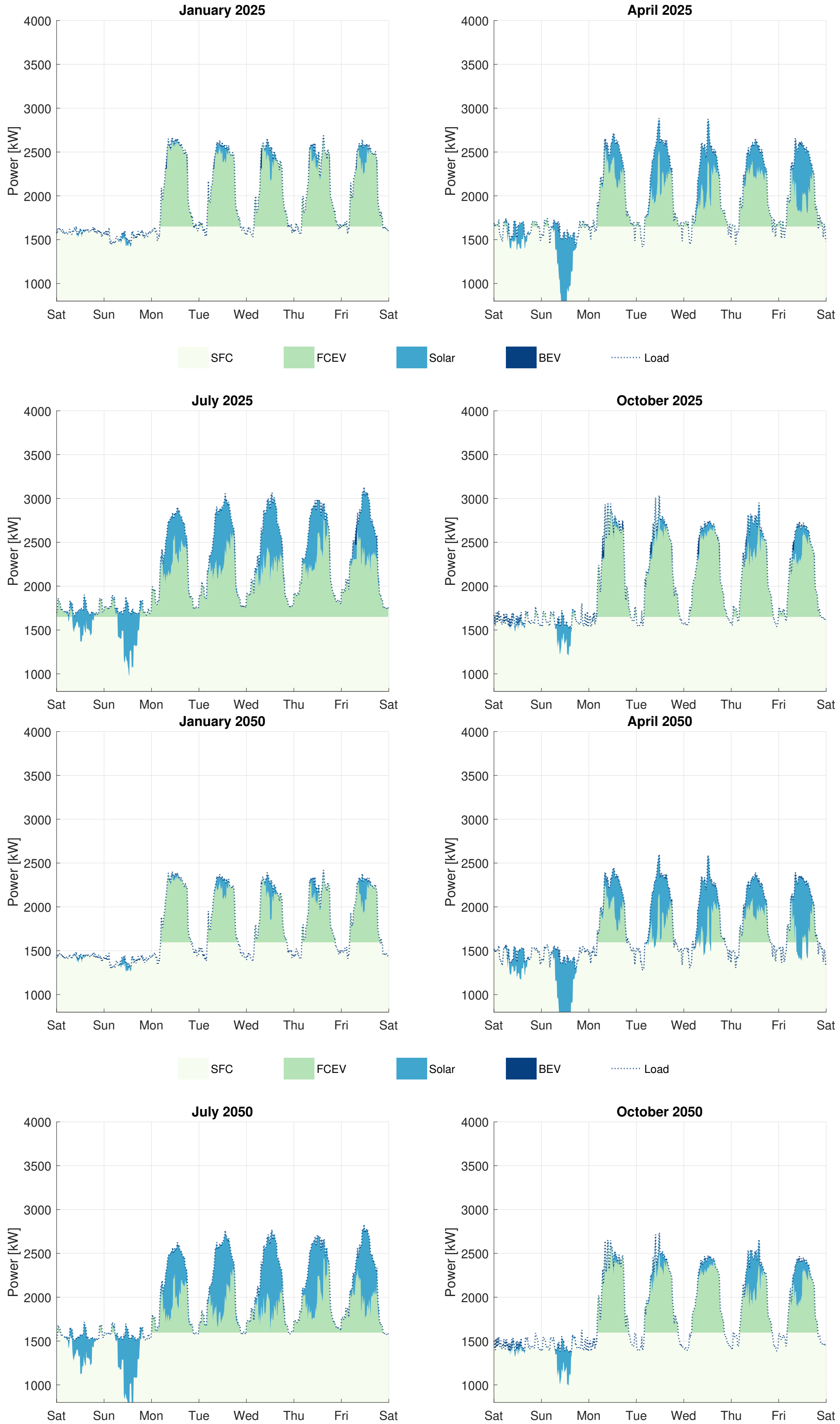


Figure 4.10: **One weekly Load Profile Plot for each season in Hydro-Electric STCA.** The generator components are summed on top of eachother, so that the total area is total production. Axis starts at 1000 kW because 0-1000 kW is constant load /constant SFC production.

kW), or solar if available. This is true for all seasons. BEVs are hardly ever utilized and therefore are nearly completely absent from the graph. In the July graph we see that the need for using FCEVs is nearly halved compared to January, for 2025. For 2050 we see that solar combined with SFC is close to sufficient for the electricity demand, but that FCEVs keep being used every day. It can also be easily derived that a solar surplus will never occur: The maximum amount that the solar PV system produces does not exceed the baseload.

In the weekly profile in Figure 4.11 we also see that wind intermittency is influencing the system behaviour heavily. Also winter energy use (January) exceeds loads above 4000 kW with everything relying on electricity (heat pump + moisturization and kitchen). During daytime (at the peaks), in some weeks it is clearly visible that BEVs are used in the morning but deplete after a few hours, subsequently they are exchanged for FCEVs. Moments where the system relies purely on grid energy are scarce. The BESS system is only capable to provide energy for a few hours each time it is employed.

Balancing by FCEVs and BEVs

Fig 4.12 shows that in the Hydro-Electric scenario, the vehicles are consistently used throughout the year, primarily during office hours. The boxplots show the pattern of usage per day throughout the entire year. The employment of vehicles is lower during the peak solar hours (between 10-14 hours), but the effect is minimal because the demand side is also generally at its highest point during this time of day. The contribution of BEVs to this distribution is very low: 1.3 % and 0.2 % respectively for 2025/2050.

The usage pattern of vehicles is drastically different from the Hydro-Electric case, which can be seen in Fig. 4.12 We should note the following main differences:

1. The range in fluctuation of usage increased sharply. The maximum used is double that of the other case.
2. Employment just before the start and right before the end of office hours is consistently low.
3. There is not an equal distribution such as in the Hydroo-Electric case.

This behaviour is explained by two main reasons: Firstly, BEV availability is constrained by the SoC of present vehicles. If the vehicles have no charge left, the system switches to a different producer. Point 2 above is explained by this phenomenon, at the end of the night or day BEV capacity will be empty because they have been used in the hours before. Right afterwards, there is a change in batch of vehicles with new SoCs, and the system starts using them again. The second reason is that the All-Electric system depends to a greater extent on the wind profile: The charging and discharging of components is directly coupled to the wind profile, making it inherently more arbitrary. In Hydro-Electric this effect is tempered due to the large single storage unit serving as a buffer before the components at STCA. The **local** Hydro-Electric system enjoys a constant supply of H_2, while the **local** Electric system is constantly influenced by wind intermittency and only relies on external storage as a last resort.

4.1.2. Economic Evaluation

The system costs are dominated by the production of electricity for hydrogen by the wind turbine, and the hydrogen production and storage (Fig. 4.14). A more detailed

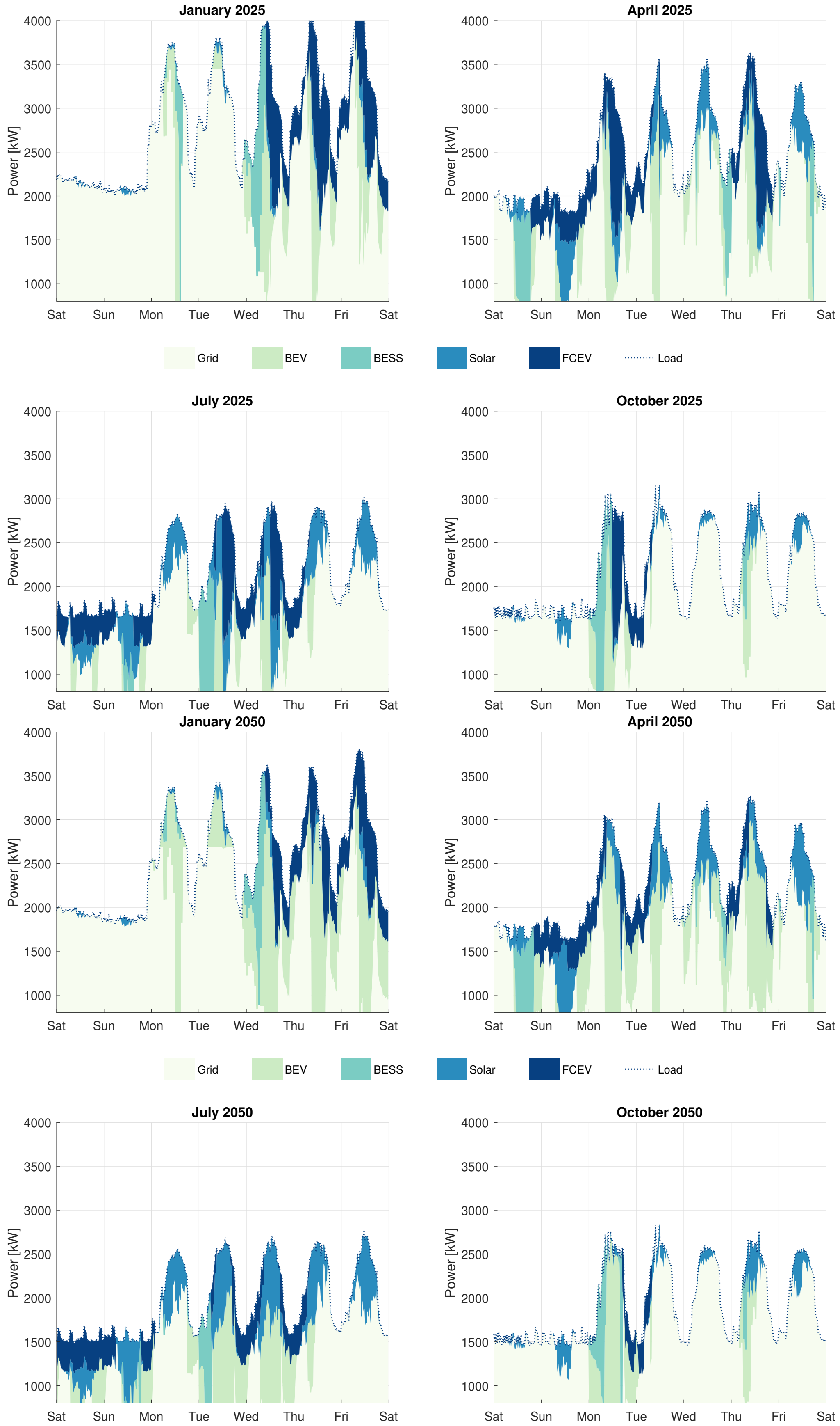


Figure 4.11: **All-Electric STCA. Load Profile Plots for every season showing total load and local generator power on a weekly timescale.**

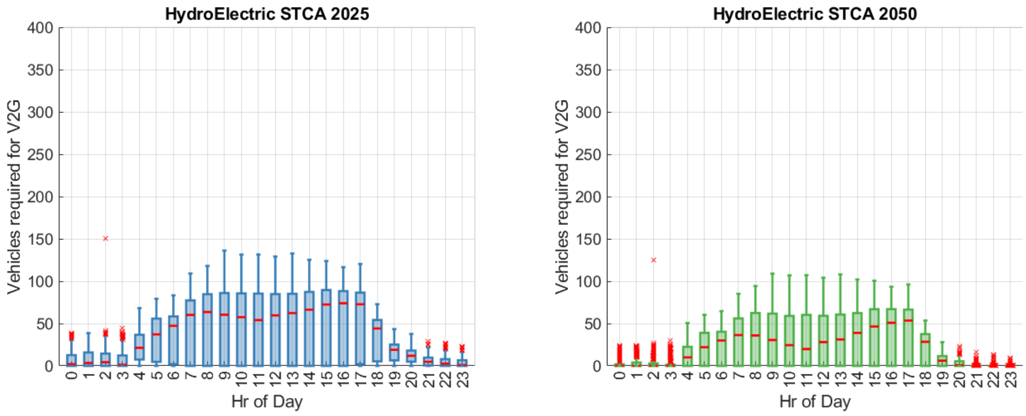


Figure 4.12: **Boxplots of vehicles required and used in V2G-mode for Hydro-Electric case STCA.** Plot showing grouped data per hour for the full year. Central red mark indicates the median, the bottom and top edges of the box indicate the 25th and 75th percentiles, respectively. The whiskers go up to extreme data points not considered outliers. The red markers are individual outliers. This graph includes the total of BEVs and FCEVs.

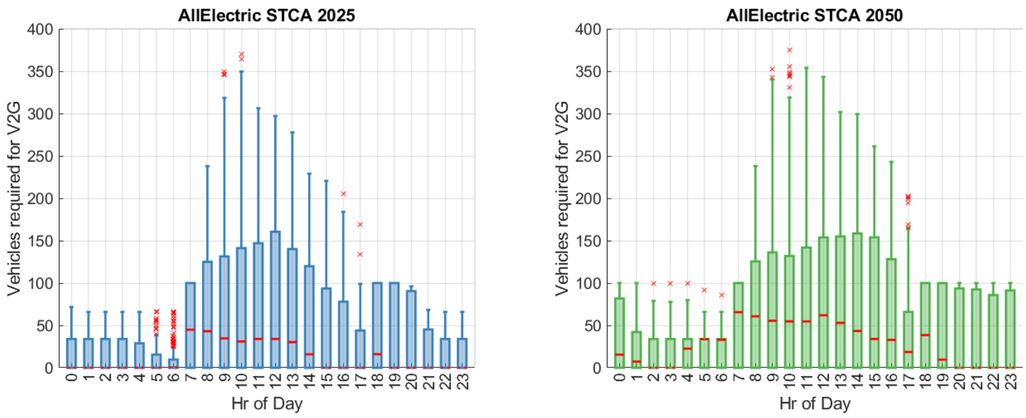


Figure 4.13: **Boxplots of vehicles required and used in V2G-mode for All-Electric case STCA.** Plot showing grouped data per hour for the full year. Central red mark indicates the median, the bottom and top edges of the box indicate the 25th and 75th percentiles, respectively. The whiskers go up to extreme data points not considered outliers. The red markers are individual outliers. This graph includes the total of BEVs and FCEVs.

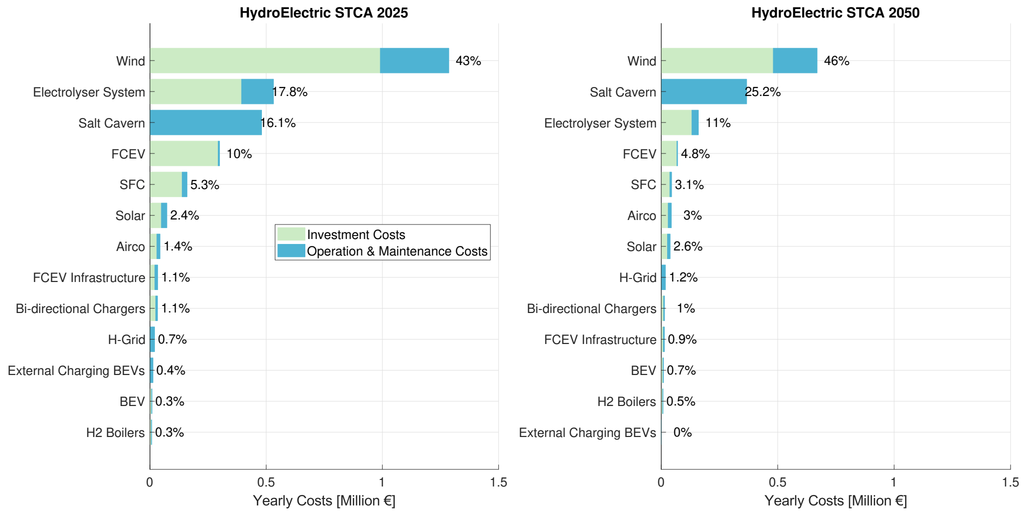


Figure 4.14: **Cost distribution of Investment Costs and Operational & Maintenance costs for Hydro-Electric STCA case.** Percentages in chart are shown compared to Total System Cost (TSC)

breakdown of component yearly costs is found in Table 4.3, where we can compare the component costs next to their size or capacity (Q). Salt Cavern capacity is reffering to the total salt cavern capacity assumed to be in operation (which we don't use in full). Total System Costs plummet in 2050, featuring a 1.26 million €/year cost reduction (43%). A much smaller wind turbine size drives down these costs, as well as lower storage costs.

In the AE case in Fig. 4.15 costs are somewhat more evenly divided. While there was opted for a small BESS, in 2025 it is still the largest component cost-wise. Bi-directional chargers are also a significant cost factor, particularly in 2025.

Local components are of lesser importance in the HE-case, meaning that the cost of H_2 is the main driver of the TSC. Cost distributions remain similar in both the 2025 and 2050 scenario, indicating that it is mostly the design that matters. A result that may be counter-intuitive is that FCEV costs are higher than SFC costs, while the SFC energy production greatly exceeds that of the FCEVs. This is explained by two factors: The FCEVs are a larger system dealing with higher peak loads (300 cars x 10 kW = 3000 kW, compared to only 1650 kW for the SFC). Also, as quality requirements for fuel cells are much higher for automotive applications, the lifetime is far lower, leading to higher yearly costs.

Table 4.1 summarizes the essential (S)LCOE values for the Hydro-Electric STCA case. Hydrogen at the system level ($SLCOE_{H2}$) is produced at 2.79 €/kg or 1.70 €/kg, in 2025/2050 respectively. $SLCOE_{BEV}$ is extremely costly and even increases in the future, because BEV_{EP} is so low, making the necessary investment costs for chargers and batteries relatively high.

We see that $SLCOE_{Q,STCA}$ is only 4 cts/kWh in 2025, mainly due to the surplus heat that the SFC provides. Total cost of electricity ($SLCOE_{e,STCA}$) is 14.6 cts/kWh in 2025 and 7.4 cts/kWh in 2050.

Table 4.4 shows why the local components costs are proportionally larger: The wind turbine is smaller. In 2025, the capacity is only 3786 kW while in Hydro-Electric it is 8263 kW. Once more, TSC is reduced significantly in the mid-century scenario, the cost reduction is 43%. We see that costs are slightly higher than the Hydro-Electric case, but not a very significant increase (see Table 4.2). $SLCOE_{BEV}$ gets very competitive in 2050.

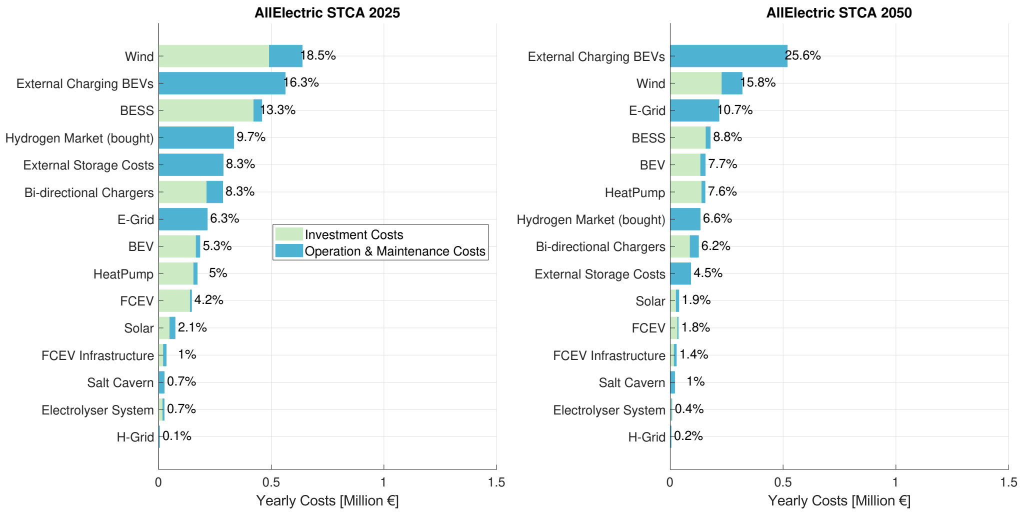


Figure 4.15: **Cost distribution of Investment Costs and Operational & Maintenance costs for All-Electric STCA case.** Percentages in chart are shown compared to Total System Cost (TSC)

Type of LCOE	2025 [€ / kWh]	2050 [€ / kWh]
$LCOE_{Solar}$	0.071	0.031
$LCOE_{Wind}$	0.029	0.019
$SLCOE_{H2}$ [€/kg]	2.79	1.704
$SLCOE_{BEV}$	1.425	6.065
$SLCOE_{FCEV}$	0.235	0.117
$SLCOE_{SFC}$	0.129	0.07
$SLCOE_{e,STCA}$	0.146	0.074
$SLCOE_{Q,STCA}$	0.04	0.028
$SLCOE_{STCA}$	**0.104**	**0.056**
$SCOE_{STCA}$ [€ / m^2/year]	29.7	14.4

Table 4.1: **System Levelized Cost end results for Hydro-Electric scenarios in Near-Future and Mid-Century**

Using the BESS however turns out to be costly, although this is the result of the low utilization rate.

4.1.3. Alternative AE Design: Large local Battery System

For this design the energy analysis figures are not shown because they are to a large extent similar to the main design. More importantly, the economic results indicated that it is not worthwhile to further pursue this design: Only the BESS costs in this case are more than the whole system in the first simulation. The $SLCOE_{e,STCA}$ was 0.54 in this case, more than 3x higher than the original system. The local BESS suffered mainly from the problem that it was underutilized.

4.1.4. Design implications

The results indicate mainly that the cost of H_2 is crucial in the implementation of a Hydro-Electric local system. If the price of H_2 is reasonable, using a SFC locally can be an economically attractive option, especially if waste heat is captured. Installing a larger SFC than the now modelled baseload would definitely bring down $SLCOE_{e,STCA}$ even

Type of LCOE	2025 [€ / kWh]	2050 [€ / kWh]
$LCOE_{Solar}$	0.071	0.031
$LCOE_{Wind}$	0.029	0.019
$SLCOE_{Wind}$	0.064	0.044
$SLCOE_{H2}$	2.972	1.867
$SLCOE_{BEV}$	0.551	0.23
$SLCOE_{FCEV}$	0.39	0.246
$SLCOE_{BESS}$	0.604	0.346
$SLCOE_{e,STCA}$	0.15	0.095
$SLCOE_{Q,STCA}$	0.077	0.053
$SLCOE_{STCA}$	**0.12**	**0.077**
$SCOE_{STCA}$ [€ / m^2/year]	34.2	20.1

Table 4.2: **System Levelized Cost end results for All-Electric scenarios in Near-Future and Mid-Century**

further, but we have to consider practical issues as space and investment costs, making this solution impractical for some office buildings. Using FCEVs in combination with the H_2 grid is a good option to deal with peak loads, but if we would not have this direct grid connection the fuel tanks would be emptied quickly.

It is clear why it was decided not not to include a local electrolyser: No surplus electricity is available to produce any H_2 locally.

The $SLCOE_{e,STCA}$ suggests that using H2 boilers is a potentially viable pathway for offices to use as their mean heat supply, although there is a lot of "free" heat available from the SFC. $SLCOE_{e,boilers}$ however is also only 7.5 cts/kWh in 2025, which seems reasonable to keep considering.

We see that that it is not uncommon to use the vehicles during nighttime, especially in the early morning (4 am - 7 am). In offices this is a time where carpark occupancy is very low, which is why I made the assumption of 100 cars in the last chapter. This requirement is a potential design issue for real-use cases. Potential resolutions to these issues are having a larger SFC, or investigate demand side management to shift loads to a more convenient time.

These designs show that even in an all-electric system it may be a better idea to have a centralized storage system with high utilization rate compared to large local battery systems. The flexibility provided though by BESS and BEV is good, and this design does increase viability for a system operated in islanded mode, if that is what the goal is.

$SLCOE_{BEV}$ does improve dramatically from 2025 to 2050. We can deduce from that the available battery capacity is a significant constraint in the cost-effectiveness of BEVs, as their battery capacity and utilization was improved significantly in the 2050 case.

Type	Unit	Near Future (2025)				Mid Century (2050)			
	[-]	Q	CC [k€/y]	OMC [k€/y]	TC [k€/y]	Q	CC [k€/y]	OMC [k€/y]	TC [k€/y]
Solar	kW	1176	49	23.9	72.8	1176	26.4	11.9	38.3
Wind	kW	8532	991	294.9	1285.9	6780	480.8	188.5	669.3
Electrolyser	kW	8800	283.9	84.5	368.4	8800	89.8	17.6	107.4
Compressor, water treatment	kg H_2/hr	160	110	53	163	130	41.4	10.7	52.1
Salt Cavern	tonnes H2 Capacity	3733	0	480.5	480.5	3733	0	366.7	366.7
H-Grid	Nm^3/h Gas Grid Type	650	0	19.8	19.8	650	0	18	18
E-Grid	MW Connection Capacity	0	0	0	0	0	0	0	0
Stationary Fuel Cell	kW	1650	138.3	21.1	159.4	1596	36.6	8	44.5
FCEV	kW of systems	15600	293.2	6.2	299.4	12700	66.9	3.4	70.2
BEV	kWh of batteries	2040	6.7	2	8.6	3400	7.1	2.4	9.5
Bi-Directional Chargers	# of 2-point chargers	17	24.4	8.1	32.4	17	10	4.3	14.2
FCEV Discharge Infrastructure	# of 4-point connectors	39	20.9	12.5	33.4	32	8.6	5.1	13.7
Airco	kW	1900	29.6	13.7	43.3	1900	29.6	13.7	43.3
H2 Boilers	kW	1286	6	1.7	7.7	1285	6	1.7	7.7
Storage Difference H2	kg	144	0	-0.4	-0.4	1183	0	-2	-2
External Charging costs BEVs	kWh	51761	0	12.9	12.9	4226	0	0.6	0.6
Total Costs			**1952.9**	**1034.2**	**2987.1**		**803.1**	**650.4**	**1453.5**

Table 4.3: **Cost tables of Hydro-Electric System Design for near-future and mid-century scenarios**

Type	Unit	Near Future (2025)				Mid Century (2050)			
		Q	CC	OMC	TC	Q	CC	OMC	TC
	[-]		[k€/y]	[k€/y]	[k€/y]		[k€/y]	[k€/y]	[k€/y]
Solar	kW	1176	49	23.9	72.8	1176	26.4	11.9	38.3
Wind	kW	4228	491.1	146.1	637.2	3227	228.9	89.7	318.6
Electrolyser	kW	400	12.9	3.8	16.7	400	4.1	0.8	4.9
Compression, water treatment	kg/h	7.3121	5	2.4	7.4	6.6667	2	0.5	2.5
Salt Cavern	kg H2 Capacity	3733	0	24.5	24.5	3733	0	19.8	19.8
H-Grid	Nm^3/h NG grid type	65	0	4.1	4.1	65	0	3.9	3.9
E-Grid	MW Connection Capacity	10	0	216.2	216.2	10	0	216.2	216.2
Stationary Battery (BESS)	kWh	12000	422	36	458	9000	158.3	18.9	177.2
FCEV	kW of systems	15400	139.9	6.2	146.1	12700	32.4	3.4	35.8
BEV	kWh of batteries	17820	166	17.1	183.2	29900	134.5	20.9	155.4
Bi-Directional Chargers	2-point chargers	149	213.6	70.8	284.3	150	87.9	37.5	125.4
FCEV Discharge Infrastructure	4-point connectors	39	20.9	12.5	33.4	32	17.2	10.2	27.4
Heat Pump	kW	3300	155.3	16.2	171.4	2970	139.7	14.6	154.3
External Grid Storage	MWh	2739	0	286.4	286.4	1686	0	91	91
External fueling costs FCEV	tons	56	0	333.6	333.6	33	0	132.9	132.9
External Charging costs BEVs	MWh	2247	0	561.8	561.8	3455	0	518.2	518.2
Difference in BESS storage	kWh	0	0	0	0	0	0	0	0
Total Costs			**1675.7**	**1761.6**	**3437.3**		**831.4**	**1190.4**	**2021.8**

Table 4.4: **Cost tables of All-Electric System Design for near-future and mid-century scenarios**

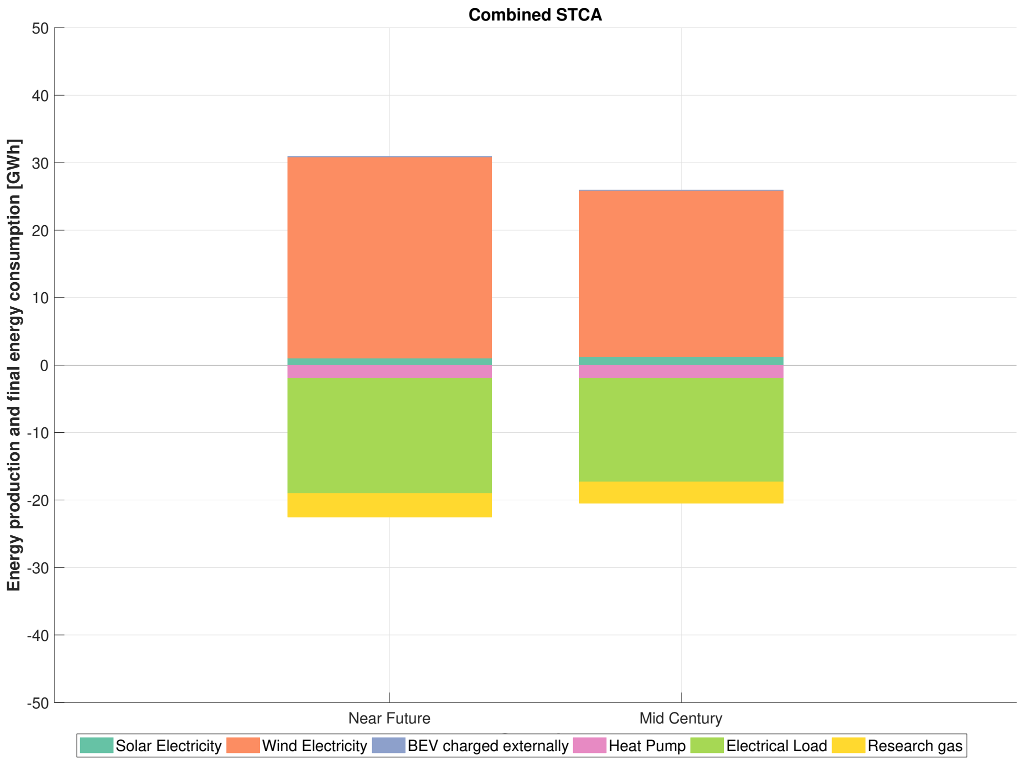


Figure 4.16: **Annual Energy Balance STCA in the Combined Case.** Original energy produced is viewed as positive, and final energy consumption at STCA is shown as negative values. Hydrogen demand is converted to kWh with HHV (39.41 kWh/kg)

4.2. Combined Scenario

For the combined case one main design is shown, the version with using the heat pum. Other alternatives are also discussed more concisely, to explore what their essential values are. Results are mostly comparable throughout the different setups.

4.2.1. Energy Analysis

In the combined case the annual energy balance is in the middle between the extreme cases. The production side is significantly higher than the consumption side, nearing 30 GWh versus 22 GWh. Again, the conversion losses are the cause of this effect. In 2050, the balance looks roughly the same, we can only notice the slight efficiency improvements reducing the production side (Fig. 4.16).

Energy flow diagram

Even with the ability to directly use wind electricity through the electricity grid, more than half of wind production is allocated to electrolysis (Fig. 4.17). Of course, this hydrogen is not all used for electricity but also for the office and research gas. Locally, direct use of electricity is still the largest contributor. We see that the storage necessity is 6365 MWh in total, which is lower compared to the all-electric case where much energy comes from external charging/fueling inside BEVs/FCEVs. The amount of hydrogen stored relative to the total hydrogen produced is high. This is because hydrogen is only produced during surpluses of electricity, therefore the storage ratio is inherently higher than in the other cases. The contribution of vehicles falls in this design, as SFC and direct use are usually

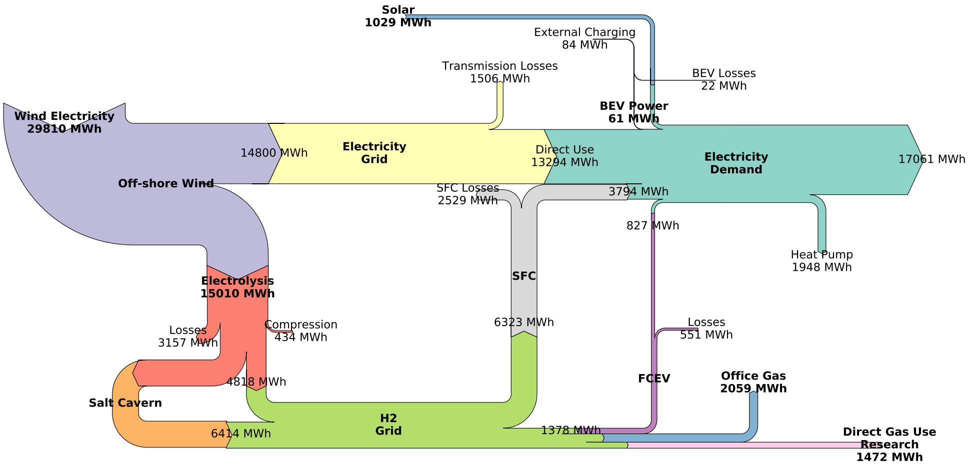


Figure 4.17: **Combined STCA 2025 Energy Flow Diagram.** Hydrogen is displayed by its energy content in HHV (39.41 kWh/kg).

sufficient. Fig. 4.18 shows that in 2050 primarily the hydrogen flow chain reduces in size, due to some efficiency improvements and the rest of the system having smaller surpluses and deficits.

The load duration curves in 4.19 make visible that the BEVs and FCEVs contribution lowers in the combined case, because the grid and SFC are sufficient most of the time. The baseload range between 1500-2000 kW can quite clearly be seen in the grid plotline.

Weekly profile plots

The combined system can operate purely on the grid for full days, as shown in Fig. 4.20. However, we can also see many hours where the grid is insufficient for extended periods of time, such as in the July plot from Tue-Thu or the April plot from Sun-Tue. In those times, the SFC is able to cover almost the base load, and peak loads are done by FCEVs, as we expect from the design. BEVs can hardly be spotted in these graphs, and are almost never used. In 2050 the necessity of cars is even further reduced during spring and summer, where solar and SFC nearly power the whole system in peak load.

Balancing by FCEVs and BEVs

In the combined case, the boxplots show a distribution with only outliers, meaning that vehicles are hardly used in this case. The grid, SFC and solar combined thus have practically always enough power available if we generalize it to a full year (Fig.4.21a). This does not mean the cars are redundant. If we go back to earlier plots such as Fig. 4.20 or 4.17 it is clear that cars still provide about 5% of energy demand. Also, in the development of this design it was tried to reduce the size of the SFC or wind turbine to give the cars a bigger role, but that led to unsolvable energy deficits at some point. The SFC needed to remain relatively large, leading to this lower usage of cars.

4.2.2. Economic Evaluation

Like in other cases, the largest expense is the wind turbine that greatly exceeds all other costs. From Fig. 4.22 we can derive that most costs lie outside of STCA, local components have lower costs. In 2050, the components costs decrease further, with instead the

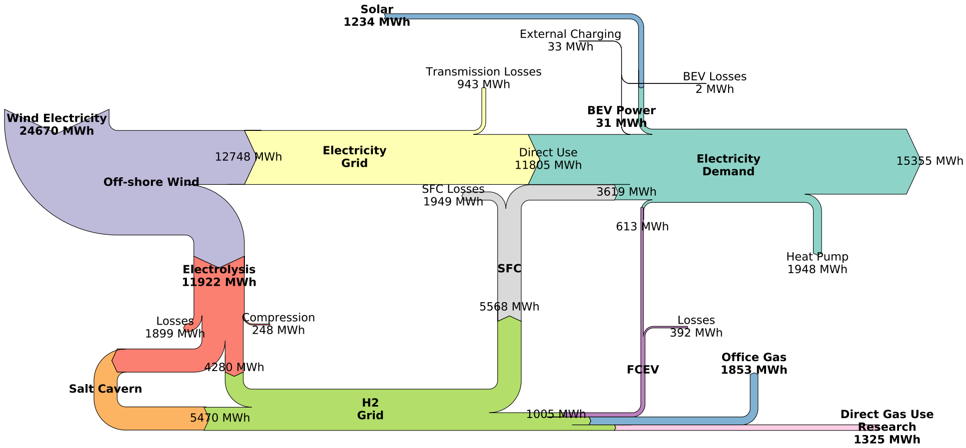


Figure 4.18: **Combined STCA 2050 Energy Flow Diagram.** Hydrogen is displayed by its energy content in HHV (39.41 kWh/kg).

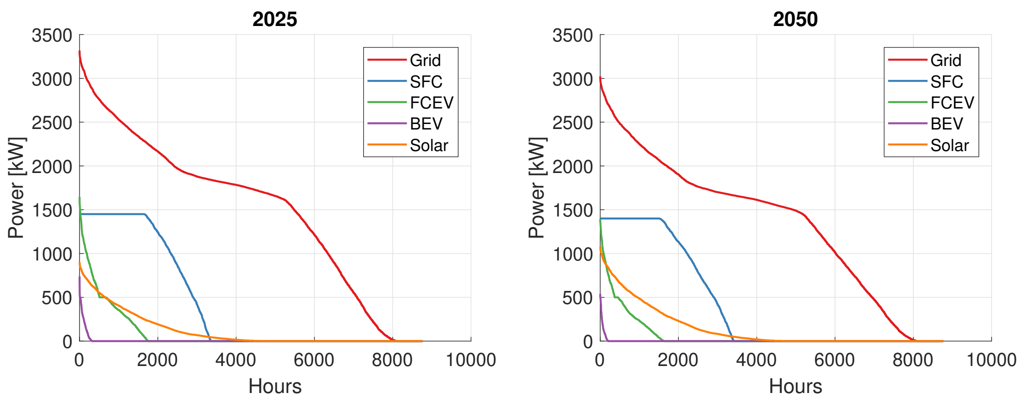


Figure 4.19: **Load Duration Curves (LDC) of Combined Scenario in 2025 (left) and 2050 (right).** The graph shows how many hours a component is used (x-axis) at a certain power level (y-axis). The area underneath is equivalent to the total energy production of that component per year.

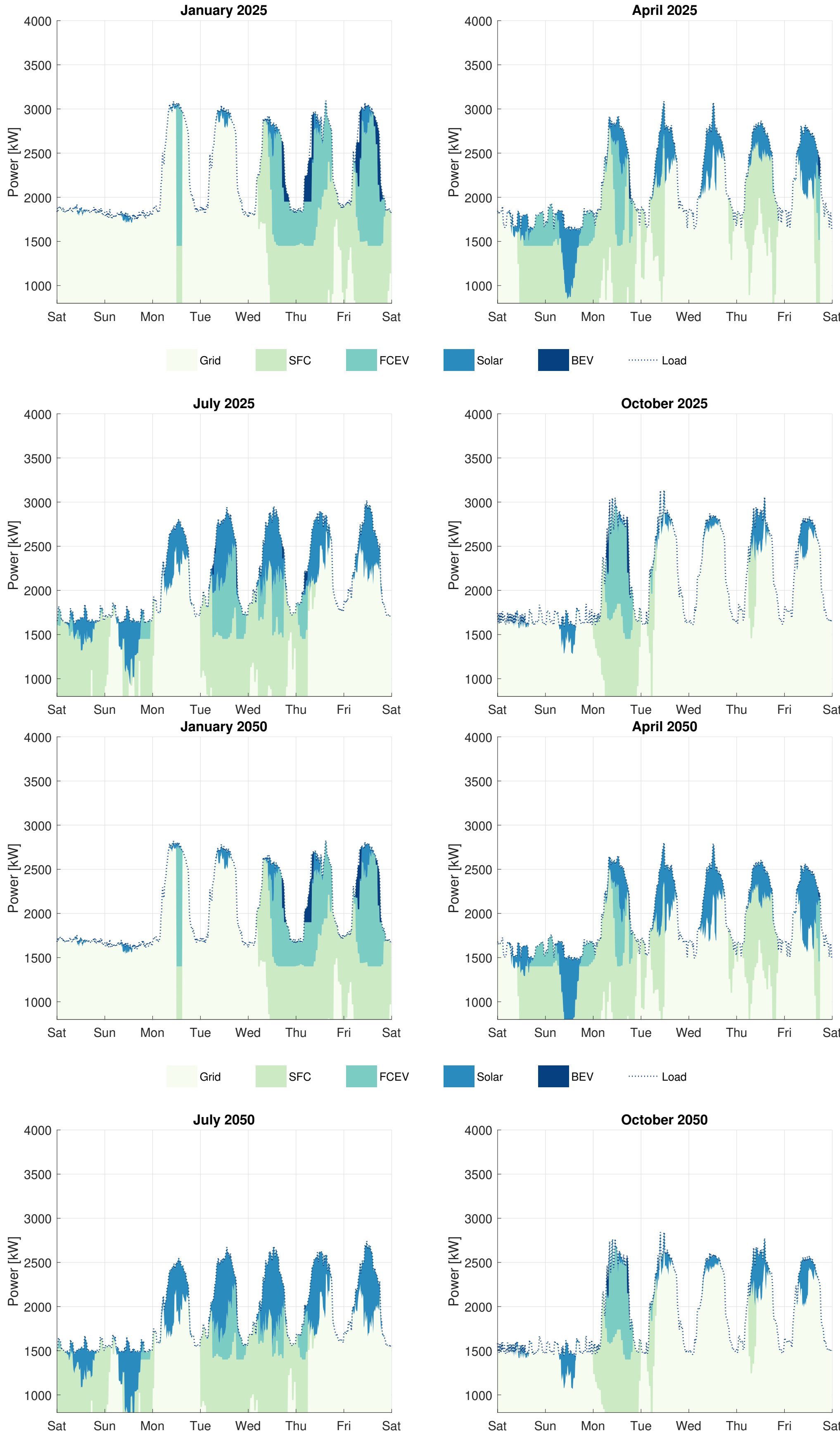
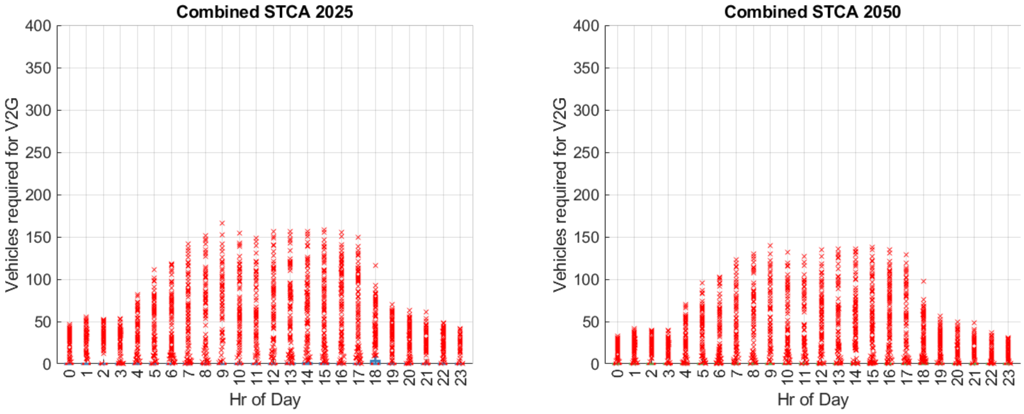


Figure 4.20: **Combined STCA. Load Profile Plots for every season showing total load and local generator power on a weekly timescale.**



(a) **Boxplots of vehicles required and used in V2G-mode for Combined case STCA. Plot showing grouped data per hour for the full year.** Central red mark indicates the median, the bottom and top edges of the box indicate the 25th and 75th percentiles, respectively. The whiskers go up to extreme data points not considered outliers. The red markers are individual outliers.

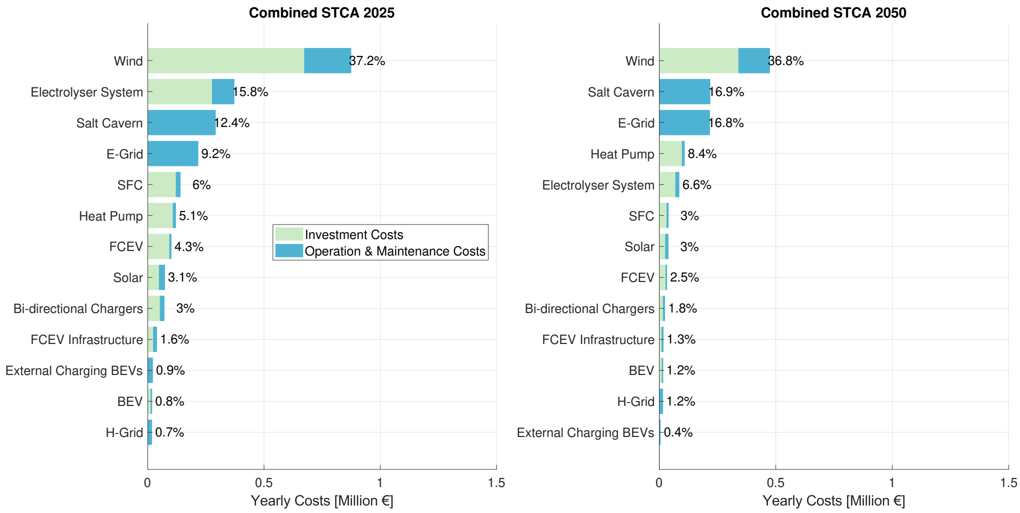


Figure 4.22: **Cost distribution of Investment Costs and Operational & Maintenance costs for Combined STCA case.** Percentages in chart are shown compared to Total System Cost (TSC)

storage and infrastructure costs having a larger role. In the overview Tables B.1 and 4.5 the TSC is €2.33/1.29 Million, meaning that this design has the lowest total cost overall. The $SLCOE_{e,STCA}$ in the combined case is 0.082 cts/kWh in 2025. It is worth noticing that $SLCOE_{H2}$ is higher, because of the larger amount of storage that is needed.

4.2.3. Alternative designs

The alternative designs and approaches showed similar responses when only changing the heating strategy. Prioritizing V2G seemed not to be an attractive option. The open system, combining both the heat pump and SFC for heating is a good exploration of what a buying consumer could do in such systems.

Employing H2 boilers and SFC

This design resembles the main combined design largely, with a distinction: the thermal demands are covered by hydrogen technology. The small change does not significantly impact end results. Costs for heating is calculated at 0.056 and 0.045 €/kWh, so slightly

Type of LCOE	2025 [€/ kWh]	2050 [€ / kWh]
$LCOE_{Solar}$	0.071	0.031
$LCOE_{Wind}$	0.029	0.019
$SLCOE_{Wind}$	0.049	0.039
$SLCOE_{H2}$ [€/kg]	3.868	2.206
$SLCOE_{BEV}$	1.786	1.418
$SLCOE_{FCEV}$	0.332	0.172
$SLCOE_{SFC}$	0.201	0.097
$SLCOE_{e,STCA}$	0.098	0.058
$SLCOE_{Q,STCA}$	0.051	0.034
$SLCOE_{STCA}$	**0.082**	**0.049**
$SCOE_{STCA}$ [€/m^2/year]	23.2	12.8

Table 4.5: **System Levelized Cost end results for Combined in Near-Future and Mid-Century, including Heat Pump as the main heat source (main design)**

higher than the heat pump (0.051/0.034 €/kWh). This is why for the final design we opted for the heat pump, but that does not mean this design is not feasible. In addition, heating costs are very dependent on the cost of input fuel, and hydrogen is slightly more expensive in the combined case than in the extreme hydro-electric case. Thus, the cost effectiveness of heating with hydrogen boilers and the SFC increases in a system emphasising hydrogen. In App.

Prioritization of V2G

The results of this design instantly showed that prioritizing FCEVs and BEVs as primary energy sources in this system does not drive down costs. $SLCOE_{BEV}$ and $SLCOE_{FCEV}$ do decrease slightly, but the overall costs for electricity $SLCOE_{e,STCA}$ increased. Using the SFC is inherently cheaper because it needs less infrastructure to use the component. The main reason is that the STCA system is too large to be operated without a significant component covering the baseload.

Open system, assuming both fully-scaled H2 and E-Grid, emphasis on SFC use.

This design operates differently than the others, and one can evaluate the weekly profile plots in Fig. B.1 in Appendix B.1. As in this case the system prioritises the use of the SFC for power and heat, the $SLCOE_{e,STCA}$ increases. We do get the expected result of $SCLOE_{Q,STCA}$ becoming very low due to the extra heat provided by the SFC. Total system costs are higher than the regular combined case, increasing by about 10% in 2025 and 15% in 2050. The higher costs are the result of the using the SFC so much which costs 12 cts/kWh instead of using the grid more which costs only 6 cts/kWh.

Because of this heightened SFC use, costs are completely dominated by the costs of buying Hydrogen, this is displayed by Fig. 4.23. While the cost of hydrogen seems to be very large, one should note that summing all external hydrogen components in the regular scenarios would provide a similar response. One remarkable result is that the costs for FCEVs are higher than the SFC, which seems unnatural. But this is because the

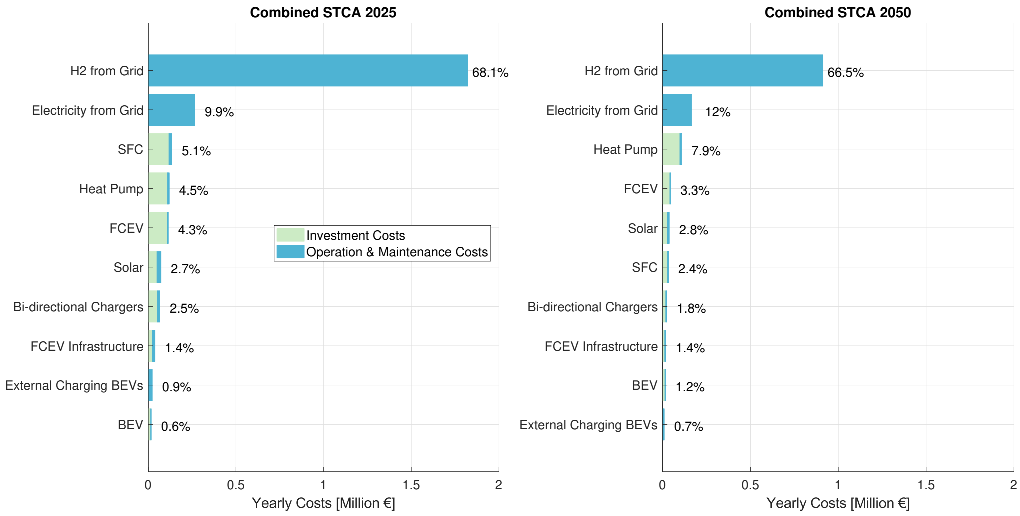


Figure 4.23: **Cost distribution of Investment Costs and Operational & Maintenance costs for Combined STCA case with open system.** Percentages in chart are shown compared to Total System Cost (TSC)

Type of LCOE	2025 [€/kWh]	2050 [€/kWh]
$LCOE_{Solar}$	0.071	0.031
$SLCOE_{Wind}$	0.064	0.044
$SLCOE_{H2}$ [€/kg]	2.79	1.7
$SLCOE_{BEV}$	1.591	0.839
$SLCOE_{FCEV}$	0.277	0.136
$SLCOE_{SFC}$	0.129	0.07
$SLCOE_{e,STCA}$	0.124	0.068
$SLCOE_{Q,STCA}$	0.026	0.016
$SLCOE_{STCA}$	**0.075**	**0.04**
$SCOE_{STCA}$ [€/m^2/year]	26.6	13.7

Table 4.6: **System Levelized Cost end results for Combined open system scenarios in Near-Future and Mid-Century with emphasis on SFC**

large capacity that is needed for peak loads requiring a large fleet of FCEVs.

4.2.4. Design implications

First, we see that for seasonal storage, hydrogen storage is more economically viable than using batteries. Centralizing storage gives us scale advantage and the cost per unit of storage is lower. Electricity is preferred though whenever energy can be consumed directly, not needing two conversion steps. The mixing of the strengths of each energy carrier is what makes the combined design so cost effective.

We still need quite a big Stationary Fuel Cell, since in the night BEV cars are empty very quickly, as there are not so many. With full capacity they can only provide power for 4.5 hours. This was less of a problem with a higher ratio of FCEVs as we could use hydrogen from the grid. One idea could be to charge them beforehand, when expecting later deficiencies, but this becomes more of a control problem. Vehicles for V2G achieve

	SLCOE [€/kWh]	SCOE [€/m^2]
Hydro-Electric		
2025	0.104	29.7
2050	0.056	14.4
All-Electric		
2025	0.12	34
2050	0.077	20.1
Combined		
2025	0.082	23.2
2050	0.049	12.8

Table 4.7: **Key findings and overview values of all cases for STCA**

lower SLCOE if used more, but overall this is not beneficial to $SLCOE_{e,STCA}$.

For the usage of vehicles and CaPP we opted to use FCEVs first because they could be connected to the grid. Not depleting owners' vehicles batteries is a good secondary goal for the system design. For STCA specifically, BEV battery capacities are just too low to be of significant use in this system. This is different in the general office case, where the energy demands are lower. Vehicle usage is still lower in the combined design due to the SFC and direct-electricity being sufficient. One could argue that a system could be designed without vehicles involved at all, but that necessitates a much larger SFC for the peak loads, which then is only used with full capacity infrequently. This would lead to larger investment costs and maybe space issues, while the usage of cars is much more flexible.

4.3. Evaluating scenarios

The crucial results of the research are summarized in 6.1.

Looking purely at the end results, we see a significant improvement in SLCOE for the combined case. Costs improve by more than 20% compared to the HE-case and more than 30% compared to the AE-case. So why is this the case? The combined case optimises the costs by combining the best part of the AE-case: Using as much electricity directly as possible, with the best part of the HE-case, long-term storage of H_2 in salt caverns. These are the main determinants of achieving these lowest costs.

Fig. 4.24 displays an overview of the total costs with their internal distribution, clustering components together into categories. In the HE-case nearly all costs go to the external production of hydrogen, while only a small fraction of costs is allocated to the local components, which serve primarily as a conversion device for transforming H_2 into electricity. In contrast, the much more emphasises local generation in the AE case makes the costs of BEV and BESS systems far higher in comparison. This is due to the fact that the charge energy is mostly incorporated in the BEV costs.

We see that the difference between All-Electric and Hydro-Electric is larger in 2025 than in 2050. Significant BEV improvements stand at the foundation of the all-electric system cost reduction: As the BEVs are heavily used, efficiency and capacity improve-

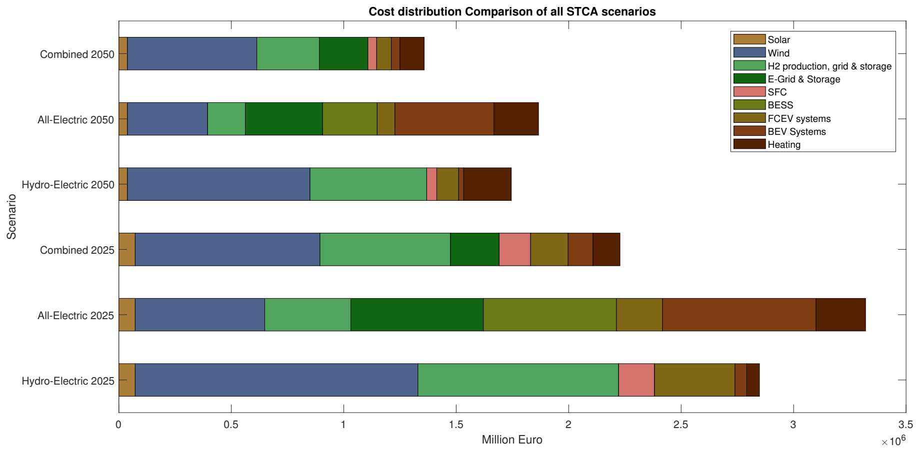


Figure 4.24: **Cost distribution comparison between all major cases for STCA.**

ments in that area are very impactful. For FCEVs, there are also improvements but their SLCOE is dictated more by the cost of H_2 than the cost of components and infrastructure.

For heating we looked at the $SLCOE_{Q,STCA}$ of both extreme cases and decided on the heat pump but still use gas for secondary heating purposes (moisturization + kitchen). Electrifying the secondary heating can lead to loads up to 1700 kW in winter, exactly at hours with low power capacities (night hours and early morning, meaning fewer cars and no solar). Just using hydrogen for this provides more flexibility and relieves the nightly electricity load. The results for levelized costs seem not very straightforward: While in the separate hydrogen case $SLCOE_{Q,STCA}$ gets very low (lower than in All-Electric), it is still better to use heat pumps in a combined case. The reason that LCOH can get so low is that we have a lot more constant 'free heat' supply in the HE case, while in the combined case the SFC is not employed at the same constant rate. Therefore the costs shift to H2-boilers for heating, which are in turn more costly than using heat pumps. Also, the cost of hydrogen dictates the cost of heat when using boilers, and we see that the cost of hydrogen is higher in the combined case.

While heat pumps are a noticeably better option in this case study, not every building is able to install them and the reduction in costs is only marginal. In future designs of other buildings usage of H_2 boilers in combination with SFC could definitely have use cases.

The grid connection capacity for electricity is very redundant, and costs could be reduced by restricting this capacity. It is currently the case that grid operators charge large consumers for the maximum power capacity instead of the energy that comes through. As we see that the fixed costs of this 10 MW capacity is quite significant (€216,000), we could investigate restricting the power capacity of the grid to achieve lower fixed costs and let energy flow through the (cheaper) hydrogen grid.

This trade-off balance could be found through optimisation and experimenting with more designs. Currently the 10 MW capacity in the combined case poses 20 % of the total costs (also because there is a lot of redundancy involved), if we would reduce this to a far smaller capacity, 2 MW for example, this would definitely improve economic performance. In the alternative designs we saw that it is not viable to increase hydrogen and SFC use to collect more heat to reduce total costs. Potential electricity grid constraints could make this more viable possible consider in future designs.

Overall, these interpretations are valid for these designs specifically. Other designs may be possible with different costs, so one should not transpose results one-on-one and state that one design approach is always more cost-effective. and should not be read as if one energy carrier is better than the other. What we can conclude is that the STCA energy system can be designed feasibly with a large variety of technologies and that these designs are all in the same order of magnitude cost-wise.

4.4. Office simulations

The results in this section are fairly similar to the results of the STCA building. Also because they are subject to the same patterns and approach that were used. Main distinctions lie in that we can greatly reduce component sizes and that cars in V2G mode start to play a more significant role. The solar system can now provide for the a larger part of energy demand, especially in the summer months. As the system scale is smaller in this scenario, the differences between the choice of energy carriers also becomes more evident when comparing results.

4.4.1. Hydro-Electric vs. All-Electric

The Hydro-Electric system generally mimics the behaviour of the larger STCA system. Still quite a large wind capacity is necessary to produce all the hydrogen, naturally leading to a relatively high amount of losses in the system. FCEVs now have a large contribution as the SFC size has been downsized as much as possible. BEVs are actually never used in this simulation. The system is about 20% of the cost of the STCA system. Local generation is more sufficient in 2050, reducing the need for a large hydrogen production capacity.

The All-Electric system performs at producing energy locally. The BESS system in the design is mostly redundant, as well as the FCEVs. BEV electricity is also featuring better economic value in this case, in contrast with the STCA scenario. The electrification of consuming components also leads to better matching and direct use of available electricity.

External storage is a big issue in the AE-case. There were never shortages that asked for external storage due to the abundance of vehicles present, so there was no real balance with the surpluses that did occur from wind or solar. Therefore, costs were taken into consideration to make use of grid-services and deal with these surpluses.

The ratio between electricity and thermal demands is smaller in this scenario than in the STCA case, allocating a larger proportion of energy to H_2 boilers and ”other gas”, which is meant for the secondary heating. The secondary heating part is out of proportion when compared to the primary heating by the H_2 boilers. This is explained in the data preparation section 3.3, and this ”other gas” component is excluded in the 2050 case. In general, the reduction in energy demand has a more drastic effect in the office scenario for mid-century than in the STCA scenario.

Use of vehicles in v2G

The baseload lies around 250 kW, corresponding to the SFC size in the HE-case. (see Table B.5). The rest of the load is covered by FCEVs and BEVs during shortages. Which are mainly used in winter months or at the edge of business hours. The V2G requirements in the office case are much lower, and with the car park that is assumed vehicles are always abundantly available.

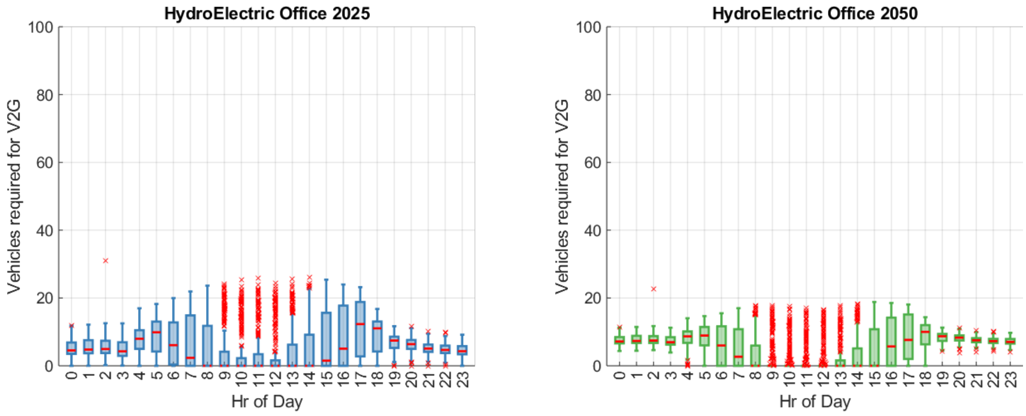


Figure 4.25: **Boxplots of vehicles required and used in V2G-mode for Hydro-Electric case Office.** Plot showing grouped data per hour for the full year. Central red mark indicates the median, the bottom and top edges of the box indicate the 25th and 75th percentiles, respectively. The whiskers go up to extreme data points not considered outliers. The red markers are individual outliers.

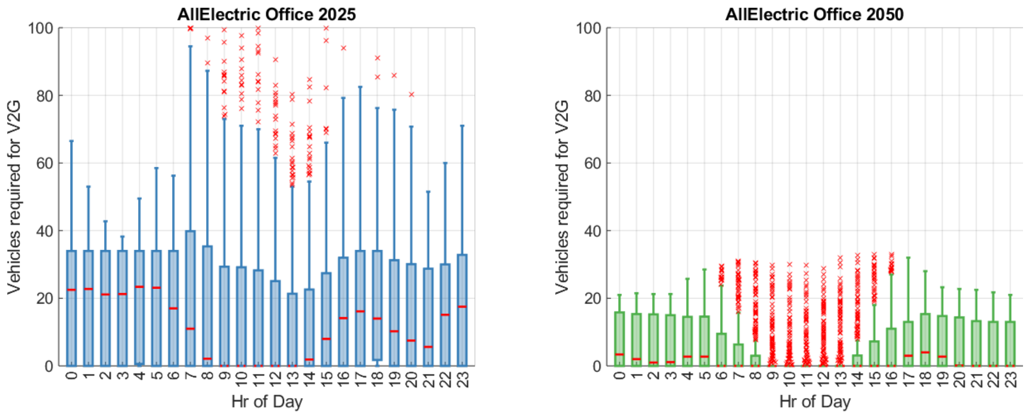


Figure 4.26: **Boxplots of vehicles required and used in V2G-mode for All-Electric case Office.** Plot showing grouped data per hour for the full year. Central red mark indicates the median, the bottom and top edges of the box indicate the 25th and 75th percentiles, respectively. The whiskers go up to extreme data points not considered outliers. The red markers are individual outliers.

In the boxplot in Fig. 4.25 the influence of solar is seen again, cars are mostly used at the start and end of the day. Overall, the amount of cars needed is quite low, we hardly need more than 20 cars. In the night the use is also constant because the SFC capacity is just below the base load. The FCEVs would be able to provide the total electricity demand if necessary.

For the AE-case (Fig. 4.26), again we see this 'wild' distribution of V2G employment, just as in the STCA case. This is caused partly too by an extra load pattern of the secondary heating, which creates high peak loads. The system relies on FCEVs sometimes only in 2025 between 4-7 AM. This is the result of several hours of wind deficiency and BEV SoCs gradually depleting overnight. In 2050, the system purely relies on solar, wind and BEVs.

The use of vehicles is generally higher in the All-Electric case, ranging from an average of 20 cars during the night to outliers nearing 100 cars during peak loads. This high utilization rate is tempered significantly in 2050, more closely resembling the other scenarios.

Type of LCOE	2025 [€/kWh]	2050 [€/kWh]
$LCOE_{Solar}$	0.071	0.031
$LCOE_{Wind}$	0.029	0.019
$SLCOE_{H2}$ [€/kg]	3.052	2.187
$SLCOE_{BEV}$	0	0
$SLCOE_{FCEV}$	0.247	0.132
$SLCOE_{SFC}$	0.14	0.089
$SLCOE_{e,STCA}$	0.157	0.096
$SLCOE_{Q,STCA}$	0.055	0.04
$\mathbf{SLCOE_{STCA}}$	0.107	0.076
$SCOE_{STCA}$ [€ / m^2/year]	12.699	4.335

Table 4.8: **System Levelized Cost end results for Office-case in Hydro-Electric scenarios in Near-Future and Mid-Century.**

Economic evaluation

Type of LCOE	2025 [€/kWh]	2050[€/kWh]
$LCOE_{Solar}$	0.071	0.031
$LCOE_{Wind}$	0.029	0.019
$SLCOE_{Wind}$	0.057	0.064
$SLCOE_{BEV}$	0.485	0.203
$SLCOE_{FCEV}$	0.437	0.252
$SLCOE_{BESS}$	0.247	0.13
$SLCOE_{e,STCA}$	0.218	0.11
$SLCOE_{Q,STCA}$	0.124	0.042
$\mathbf{SLCOE_{STCA}}$	0.173	0.084
$SCOE_{STCA}$ [€ / m^2/year]	20.5	4.8

Table 4.9: **System Levelized Cost end results for Office All-Electric scenarios in Near-Future and Mid-Century**

The smaller scale of these systems leads to higher costs per unit of energy. However, in the system levelized cost values we see that the increased usage of cars reduces their SLCoE (Table 4.8). $SLCoE_{FCEV}$ improves to 13 cts/kWh in 2050, making FCEVs a viable alternative as a flexible energy producer. $SLCOE_{BEV}$ reach a cost of 20 cts/kWh in 2050 in the AE-case, so they are somewhat less attractive.

The costs are reduced greatly in 2050, while most proportion remain the same. Two exceptions can be seen though: the solar costs are relatively larger and electrolysis and wind costs lower. In the Tables in App B.3 this can be further analyzed. The TSC are reduced sharply in 2050, by more than 60%. The AE-case makes the greatest jump because it can more easily deal with renewable intermittencies using increased efficiencies and capacities from the Mid-Century case.

The bi-directional chargers are a very costly component in the near-future case, al-

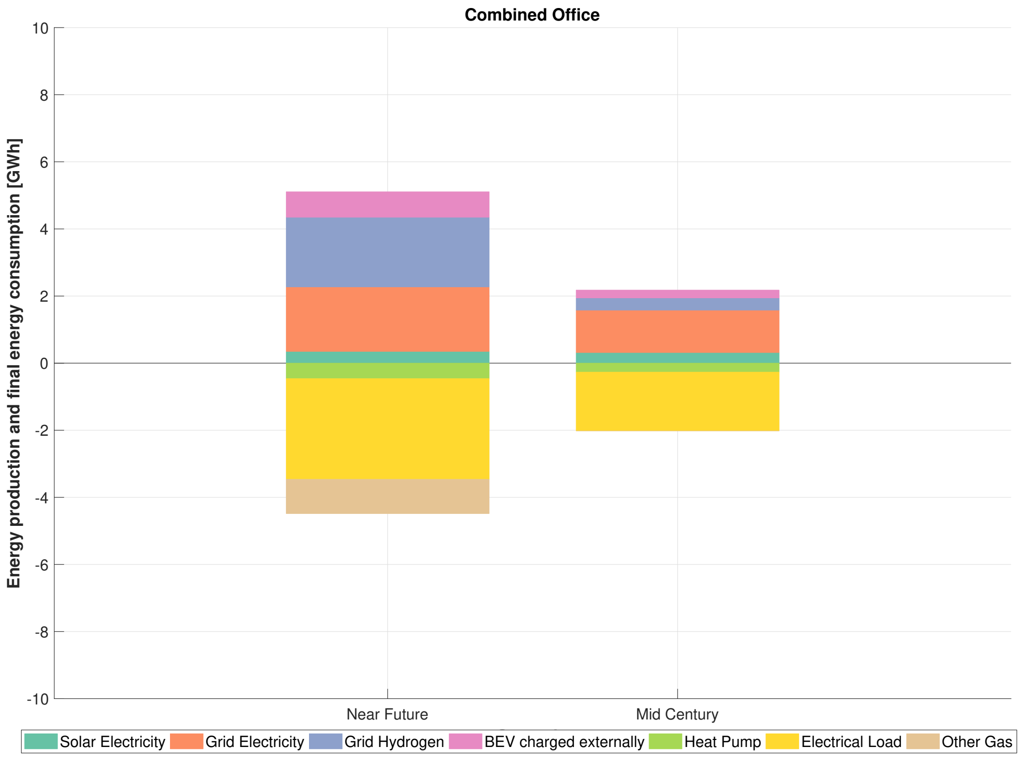


Figure 4.27: **Annual Energy Balance Office in the Combined Case. Original energy produced is viewed as positive, and final energy consumption at STCA is shown as negative values.** Hydrogen demand is converted to kWh with HHV (39.41 kWh/kg)

though this can be partly devoted to some of the peak outliers of BEV usage, requiring a high amount of chargers. The assumed higher price for hydrogen that is fuelled externally attributes to the the market hydrogen costs, that pose a serious part of the costs in 2025 too. Their assumed constant cost throughout both 2025 and 2050 is one underlying reason that this happens (see Table B.6 for the more detailed numbers).

4.4.2. Combined Scenario

In the last system design the pattern of the STCA scenario is repeated. By making use of both energy carriers we can reduce TSC to the lowest of the three scenarios. FCEVs and BEVs are used evenly in this scenario, so that we can rely on only the CaPP concept, solar and grids with no extra local components.

Energy Analysis

We see that the grid imported energy transforms from a hydrogen dominant to a electricity dominant system. Although, analogue to the other office cases this can be devoted to the ”other gas” component mainly. We also see in Fig. 4.27 that we do not have large conversion losses locally, since the consumed energy is only a fraction lower than the supplied energy, especially in 2050.

Balancing by FCEVs and BEVS

The boxplots in Fig. 4.28 show nothing that has not been shown before. Car use is pretty consistent throughout the night, and is not needed during peak sun hours in 2050. Peak vehicle usage lies around 50 cars in 2025.

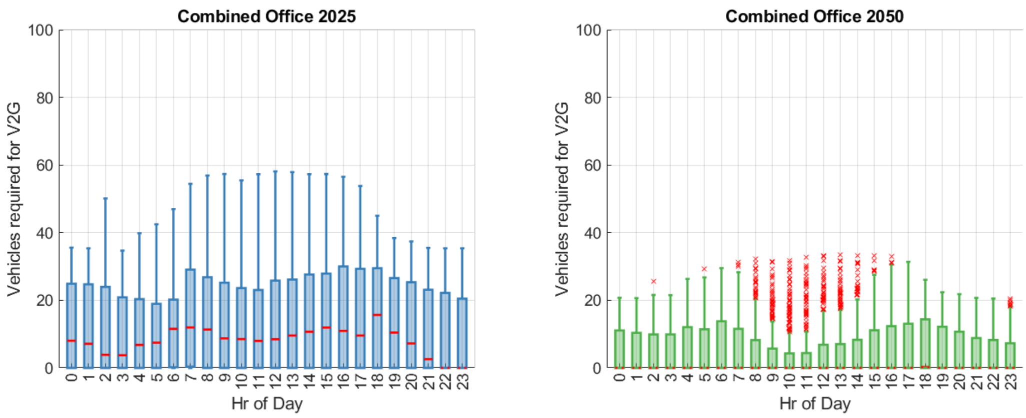


Figure 4.28: **Boxplots of vehicles required and used in V2G-mode for Combined case Office.** Plot showing grouped data per hour for the full year. Central red mark indicates the median, the bottom and top edges of the box indicate the 25th and 75th percentiles, respectively. The whiskers go up to extreme data points not considered outliers. The red markers are individual outliers.

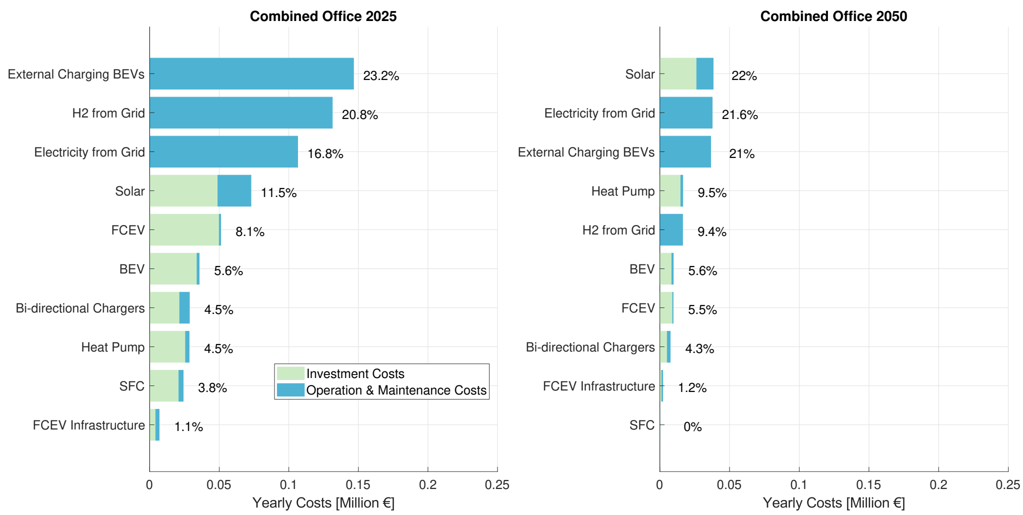


Figure 4.29: **Cost distribution of Investment Costs and Operational & Maintenance costs for Hydro-Electric Combined case.** Percentages in chart are shown compared to Total System Cost (TSC)

Economic Evaluation

The large cost overview table can be found in AppB.3 in Table B.7.

The economics show that first hydrogen is used more in 2025, and in 2050 the costs switch to electricity. This can mainly be attributed to that the system simply needs less gas in 2050, and has less to do with cost improvements of components. $SLCoE_{e,STCA}$ is reached of 8.9 cts/kWh, naturally the lowest of the three scenarios. BEVs are the more costly option for vehicle to grid, the difference is large due to high external charging costs (see Table 4.10. As they are used so frequently in this case, the costs are determined more by the energy carrier that fuels them, which is advantageous for FCEVs.

We see that the combined case has the lowest costs in 2050 6.2, but not in 2025. Using vehicles more is not the most cost-effective solution in 2025, but in 2050 it seems viable.

Type of LCOE	2025 [€ / kWh]	2050 [€ / kWh]
$LCOE_{Solar}$	0.071	0.031
$SLCOE_{Wind}$	0.064	0.048
$SLCOE_{H2}$ [€/kg]	2.79	1.87
$SLCOE_{BEV}$	0.474	0.334
$SLCOE_{FCEV}$	0.238	0.129
$SLCOE_{SFC}$	0.755	950.178
$SLCOE_{e,STCA}$	0.168	0.089
$SLCOE_{Q,STCA}$	0.061	0.037
$SLCOE_{STCA}$	**0.115**	**0.069**
$SCOE_{STCA}$ [€/m^2/year]	13.6	3.9

Table 4.10: **System Levelized Cost end results for Combined open system scenarios in the office Near-Future and Mid-Century when using FCEVs and BEVs as a priority.**

	SLCOE [€/kWh]	SCOE [€/m^2]
Hydro-Electric		
2025	0.107	12.7
2050	0.076	4.3
All-Electric		
2025	0.173	20.5
2050	0.084	4.8
Combined		
2025	0.115	13.6
2050	0.069	3.9

Table 4.11: **Key findings and overview values of all cases for Office**

Sensitivity Parameter	Contents	Values tested
SFC	IC of SFC.	±10%
H2 production and storage	Salt Cavern [€/kg H_2 stored]. IC of: Electrolyser, water treatment and compressor.	±10%
FCEV	IC of: FCEV and Discharge infrastructure.	±10%
BEV	IC of: BEV, bi-directional chargers and external charging costs	±10%
Stationary Battery	IC of: BESS and External Storage.	±10%
Battery Lifetime	LT of: BEV, BESS and External Storage.	±10%
Wind	IC of wind turbine.	±10%
WACC	WACC (= discount rate)	0.01 - 0.05

Table 4.12: **Input parameters altered for the sensitivity analysis per sensitivity parameter chosen.** IC stands for Investment Costs and LT for lifetime.

4.5. Sensitivity Analysis

As we discussed in the Methodology chapter in Section 3.1.5, parameters were chosen according to the drafted requirements. Hereby it should be repeated that some parameters were omitted because they were already modified abundantly during the initial design and modelling process (e.g. wind turbine size, SFC size). Table 4.12 shows which parameters were selected as a consequence of the final designs.

The adjusted input parameters include the WACC, SFC, Hydrogen production components, Hydrogen price, BEV, Wind turbines and stationary batteries (2x). The Investment Cost (IC) parameter of each component was substituted for either a 10% higher cost or 10% lower cost.

One exception to this method is the WACC, for which the value was hand-picked at 0.01 for the lower value and 0.05 for the higher value (the original input parameter for WACC was set at 0.03). The discount rate is a particularly case-specific parameter because it depends on location, interest and inflation rates and market conditions. The original value chosen in this research was selected before in [54, 115] and is suited for the goals of governmental and research institutions. Also commonly used is 0.05 (the high value in the sensitivity analysis), for example in [109]. In a more business-like environment as Shell one would opt for a value of 0.07.

The parameter 'Hydrogen production Components' is a bundle of the components Electrolyser, Pure Water tank , Water purification and Salt Cavern. The salt cavern is evidently not a production component but is included anyway because it is such a crucial component for the hydrogen supply chain. The hydrogen grid costs were excluded because the prices obtained for gas piping were relatively certain. Thus, for this bundle parameter the IC of every specified component is altered by ±10%.

The 'H2 SLCOE' parameter is a slightly more blunt approach to the sensitivity analysis, where we are not changing individual start parameters but instead alter the total

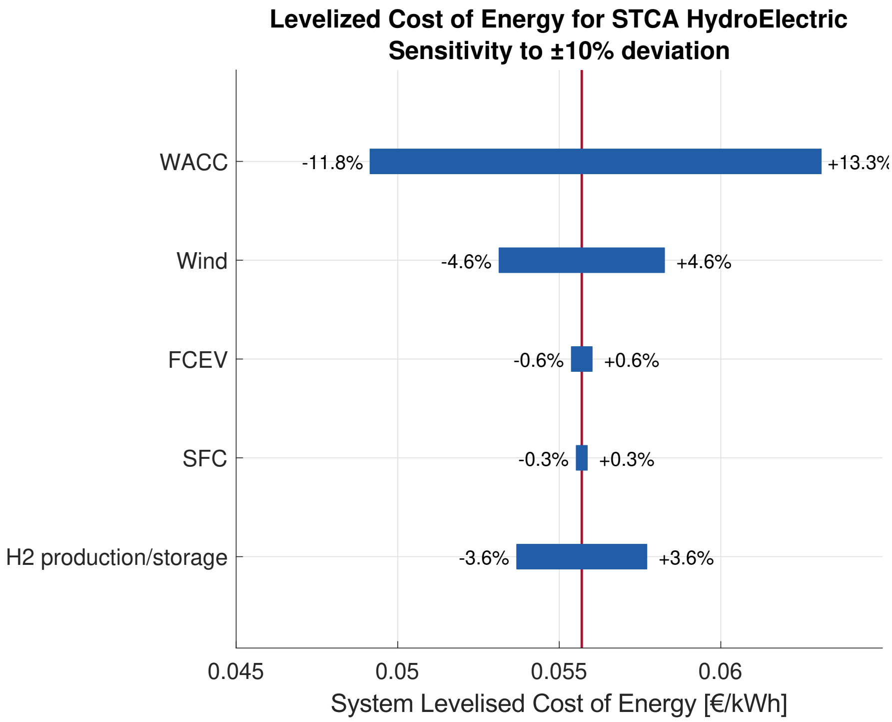


Figure 4.30: **Sensitivity analysis Hydro-Electric STCA scenario (2050).** The vertical red line represents the original value. Components were altered ±10% as seen in Table 4.12. *For WACC a range between 0.01-0.05 was used. Percentages shown in graph are the relative change of the total system in response to the parameter deviation.

hydrogen cost (thus incorporating the full supply chain) by ±10%. This simplified technique does make us able to evaluate the sensitivity for many parameters at once, and is therefore useful. Additionally, it is very relevant to the Open System simulations in the combined case, although not analysed in this section.

The lifetime of batteries is a big uncertainty in the model (see the section about batteries [ref]) and potentially influential in the total results, giving reason to include this in the sensitivity analysis as well. This includes both the stationary battery (BESS), BEV and consequently also the External Storage, which is partly based on BESS. In this research we opted for a deviation of ±10%. As future costs are very uncertain, the deviation could potentially be far higher than 10%. If we would have knowledge of the probability of our predictions a much more complex analysis could be carried out, such as a Monte Carlo simulation [135]. Hence, this sensitivity analysis should not be relied on as a prediction window, but serves rather as guidance for the relation between parameters and the end result.

In 4.30 it becomes clear that in the hydrogen case the investment cost of fuel cell systems (whether SFC or FCEV) is not very significant in the end result. The hydrogen cost, however, has more impact on the end results, and we see that the production components of hydrogen contribute only about half of this effect. The WACC is the most significant and sensitive factor in this analysis.

Increasing the WACC by 0.02 leads to a relative change in the end result of +13.3 %. The second largest difference is caused by wind with +4.6%. In the case of decreasing costs the results are symmetrical, but notably not always. Consequently, this behaviour of the analysis suggests an approximate linear relation between the IC and end result

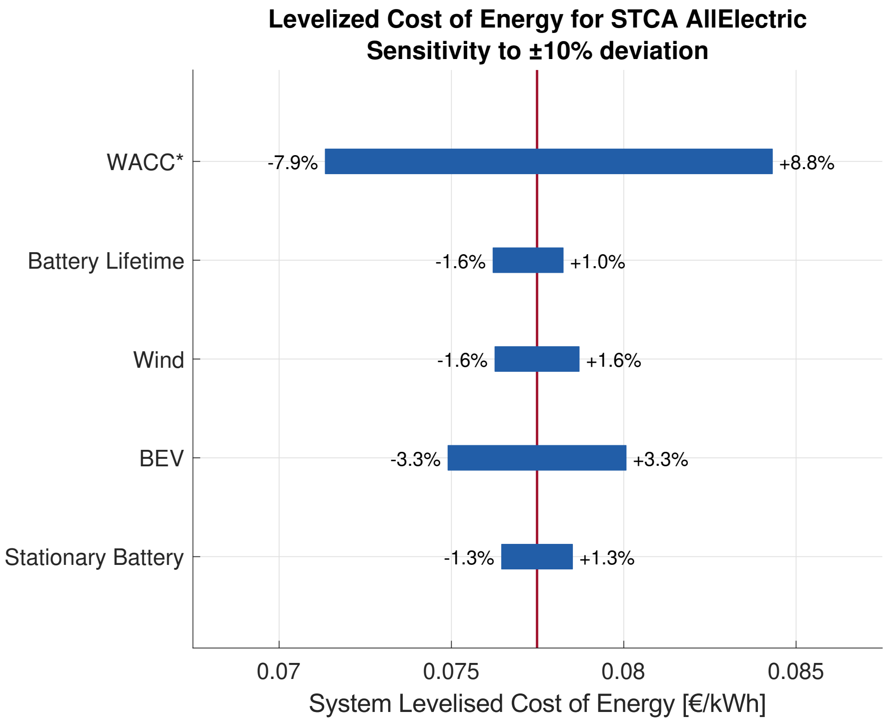


Figure 4.31: **Sensitivity analysis All-Electric scenario (2050)**. The vertical red line represents the original value. Components were altered ±10% as seen in Table 4.12. *For WACC a range between 0.01-0.05 was used. Percentages shown in graph are the relative change of the total system in response to the parameter deviation.

effect. For the office case the results are fairly similar, we do see that local components have a slightly larger impact. This can be devoted to the smaller scale of the system.

For the AE-case the scenario it was expected that total battery costs in different areas would have a large weight in the end results, yet the analysis shows otherwise: While the effects are considerably higher than for hydrogen components, it would be distorted to state that battery costs are a decisive parameter in this model. In fact, non of the tested parameters seem dominant in defining the outcome. WACC is again an exception here, as was explained above

These results does raise questions on what factors are actually crucial. Multiple explanations are possible and the answer is a combination of the following: Firstly, the main issue to consider is that costs are mainly driven by the energy supply and demand mismatch, leading to forced combinations of component sizing and use. Moreover, the fact that the system design relies on many components working together is a stabilizing factor on the sensitivity of the end results cost-wise. However, if in the designs we opt for one dominant component in size and use, the results can be considerably more sensitive. This can be seen in the simulation of the large local battery in the all-electric case.

Overall, the main deductions to take from the sensitivity analyses are that the results are adequately robust, notably for component investment costs. It was chosen to evaluate the $\text{SLCOE}_{\text{STCA}}$ for the sensitivity analysis. One of the main concerns of this research is the comparison of hydrogen vs. electricity and this analysis shows that a discussion about the exact investment costs of each component is not relevant. Far more important than these input parameters are the actual design choices concerning sizing and control and some other key assumptions.

5

Discussion

This chapter reviews the research done in this thesis and uncovers the main assumptions and limitations. Being aware of these factors puts the conclusions made in the next chapter into perspective. Also, suggestions are done for further research accompanied by notions for decision-makers on how they can use these results.

Since we need to make predictions about the future cost of technologies and their design improvements, there is a high level of uncertainty in our analysis, despite using the most substantiated projections available. This uncertainty is most prominent in the input parameters of the Mid-Century case.

The main measure taken to mitigate this uncertainty is the sensitivity analysis. This analysis showed that most result interpretations can tolerate the changes in parameters and still be valid. This validation significantly strengthens the robustness of the upcoming conclusions.

Scenario comparison obstacles

One should be careful in comparing the end results of each scenario directly, since minor adaptations in the approach were introduced to fit each scenario. For example approach of solving the supply and demand mismatch is different, as in HE there is always the hydrogen grid readily available and used constantly, where in AE we also solve the mismatch by using local components first. This leads to the case where in the HE-case the intermittent wind profile is tempered by the salt cavern, while in AE this intermittency is noticed directly. Using both local and central storage in AE was not an economic design choice.

A similar issue is with the use of the local BESS in the AE case. In most simulations, costs would decrease when the BESS was downsized. However, we are exploring designs to evaluate their feasibility, this study is not an optimization effort. Therefore, it is good to experiment with different types of designs to gain insight in what paths should be further deepened.

Notable model limitations

- The 'office´ case is a conversion from the STCA case using the STCA patterns, which do not resemble an average office on every aspect. Hence, the design can be modified and optimized in different ways to be a better representative for an average office building. For instance, the size of the parking lot can be smaller or we can limit the number of BEVs and hence, the number of bi-directional chargers.

- Grid costs remain constant and we assume the grid operator tariffs of 2018. We use the costs for the existing electrical connection which is very redundant with 10 MW. For Hydrogen we incorporate no real redundancy except for the capacity category that the system falls in. A quick calculation shows that doubling hydrogen capacity would increase total costs in HE-2025-STCA by about 1%. Even reducing the electricity grid costs by € 170 000 to equate it to the hydrogen grid costs would only reduce total costs by 6% in All-Electric case, which is still higher than Hydro-Electric.

- There was a fixed (10 kW) rate for charging and discharging the FCEVs and BEVs. Implementing dynamic charging and discharging rate widens the range of options in supply and demand of energy. This could potentially improve the efficiency and economics of the system.

- Demand Response Management (DRM) is not considered in this research, while it could be a very valuable addition to dealing with the intermittency and reduce the necessity of large storage capacities.

- It is assumed that the system is allowed to use vehicles as it pleases, while in reality these vehicles are owned by individuals. So either this design should feature only cars that are owned by the building itself, or arrange willingness with the vehicles owners, by introducing incentives for them.

- For the owner of a BESS with sufficient size, the BESS has potential to be used for grid services, gaining revenue for the owner [92]. Implementing these aspects could make BESS designs more attractive.

- Power factor is not considered because it is implicitly incorporated in component costs and losses. Analysing power system dynamics would increase the accuracy of the model but is not relevant in this context since it is part of a larger system. Also there are, except for the wind turbines, no components with a large power factor impact.

In a more elaborate sensitivity analysis additional parameters could be evaluated that proves some valuable insight:

- Changing weather profiles of wind, solar irradiation and temperature especially over a full year would be a good additional indicator if designs are redundant or lack capacity.

- Efficiencies of components could also be a parameter to consider, however the level of certainty is much higher here than with costs, as we can derive much from physics.

- Implementing more dynamic car park profiles would yield more insight in how large the car park should be to be valuable for CaPP.

5.1. Recommendations

While the approach of this study has been quite broad, many aspects that deserve attention have not been fully explored yet. On the academic level, many continuation ideas rose up during the process of this thesis, of which the main ones are listed below. In addition, this research could also serve as a guidance for either policy makers or practitioners looking for strategies or implementations in this context. Therefore, the recommendations are twofold:

Scientific continuations

- It would be interesting to play with the installed volume of BEV charging points / FCEV infrastructure. that are available to work towards optimal amounts of charging points (with different goals in mind: Lowest LCOE for office, sufficient charging availability for cars).
- Implementing energy market dynamics could reshape the use cases of some components. Daily dynamic pricing coupled to the national renewable power in the grid could incentivize more local generators or storage units. Introducing these aspects would yield some valuable design and control studies.
- Larger scale pilot projects are the most concrete actions towards expanding knowledge about these energy systems, and should be arranged, for example at STCA. Monitoring these projects would yield insights on if these designs perform equally as in the models.

Recommendations for STCA / office buildings

- Smart demand management. The heat pump is suitable for using as a demand response unit, and operators could investigate loads that could be delayed in time to provide response services.
- High redundancy at STCA may not be necessary in the future with so many distributed generators. The risks of a power outage are lower because if a single component fails there are more components to back it up.
- STCa could start experimenting with small V2G fleet to cover peak load in morning and re-charge by solar between 12:00-14:00. These times would be the most beneficial too actually introduce this concept.
- Explore options of natural gas replacement by hydrogen-based units (stationary FC, boilers, incinerator, etc.), start gradually replacing components.

Implications for policy

- Policy makers with the ambition of nourishing development towards 100% renewable energy systems should focus on promoting large-scale, seasonal storage, such as hydrogen salt caverns. Storage and flexibility are the main bottlenecks in this transition, and many short-term storage solutions became feasible recently. Long-term storage however is still lagging but becomes more important with higher ratios of renewable energy.
- The design of energy infrastructure should be done smart and holistically. The increasing complexity and variety of options require tailored solutions. This research

indicates that design feasibility is very location- **and** situation-specific. Taking the Netherlands as an example, our extensive gas infrastructure makes the use of hydrogen easier to implement, and the good wind speed profiles in the North Sea are perfect for large hydrogen production plants. Countries with other characteristics should exploit their own advantages and design accordingly.

- Still, the calculated end values for SLCOE or SCOE shown in this research can be used as a reference in decision-making for pathways of energy developments. The numbers provide clear suggestions which technology options are favourable and this justifies the choice of a certain strategy. Nevertheless, decision makers should always compare these results to other studies using the same metrics.

6
Conclusion

The goal of this research is to obtain evidence on the feasibility of using different energy carriers and integrated mobility systems at an office building, starting with the controlled environment of Shell Technology Center in Amsterdam. The results show that systems like these have clear potential use cases. The research question was: *How can we effectively design a 100% renewable integrated energy and transport system using both electricity and hydrogen as energy carriers for an office, starting with the control environment at Shell Technology Center Amsterdam?*

Table 6.1 and 6.2, repeated from Chapter 4, summarise the system levelized cost and the SCOE of each scenario. The results in this research indicate that mixing energy carriers in the design of energy systems yield the lowest costs. They also show that the cost of H_2 is crucial in the implementation of a Hydro-Electric system, this is the number one determinant. If we cannot achieve large-scale low cost hydrogen supply, hydro-electric systems will struggle to be competitive.

Scaled, centralized production and storage of hydrogen will be the future's most cost-effective solution for long-term storage of electricity. The huge capacities of salt caverns accompanied by their low costs synergise well with the large seasonal surpluses that are experienced from off-shore wind parks.

Local storage technologies such as BESS or small electrolysers are hard to justify in an office environment. When we only look at energy balancing on a 15-minute timescale they turn out to be underutilized and therefore expensive. Considering dynamic electricity market pricing or other DRM incentives may alter this conclusion. Nevertheless, it will usually be hard to install sufficient local generators in an office environment to fully use such storage systems.

In offices, vehicles can be successfully integrated as flexible power plants. Both FCEVs and BEVs are suitable for this task, although FCEVs enjoy a lower SLCOE in most cases. With this statement it should be considered that FCEVs use hydrogen from the grid directly, and BEVs mainly use electricity from (costly) external charging. The costs would be roughly equal when both types are employed equally and both use the tank/battery. The amount of cars that is needed is also within the range of the average office car park, meaning that this would be viable in practice too.

To a lesser extent, BEVs can also function as a storage unit. In practice, the state of

	SLCOE [€/kWh]	SCOE [€/m^2]
Hydro-Electric		
2025	0.104	29.7
2050	0.056	14.4
All-Electric		
2025	0.12	34
2050	0.077	20.1
Combined		
2025	0.082	23.2
2050	0.049	12.8

Table 6.1: **Key findings and overview values of all cases for STCA**

	SLCOE [€/kWh]	SCOE [€/m^2]
Hydro-Electric		
2025	0.107	12.7
2050	0.076	4.3
All-Electric		
2025	0.173	20.5
2050	0.084	4.8
Combined		
2025	0.115	13.6
2050	0.069	3.9

Table 6.2: **Key findings and overview values of all cases for Office**

charge and the battery capacity of BEVs arriving at office buildings lead to only sparse actual storage opportunities.

The key problem to solve in this research was to investigate the options on how to deal with the inherent power supply fluctuations of a fully renewable energy system. Our main expectation was that the implementation of both hydrogen and electricity as energy carriers in a single system would be the most cost-attractive. With the results of this thesis we can conclude that this hypothesis is valid. The variety of designs suggest that a future with many different system topologies per situation is needed and is cost-efficient.

A

Detailed Component Equations

A.1. Compressor

To calculate the energy needed (W [in Joules]) for compression an equation from Meier et al. is used [86]. The equation is written as follows:

$$W = \frac{n \cdot R \cdot T \cdot \ln \frac{p_2}{p_1}}{\eta} \tag{A.1}$$

where, n is the molar amount of H_2, $R$is the universal gas constant (8.314 J/mol/K) and p_1 and p_2 are the pressure before and after compression, respectively. η is the compressor efficiency, assumed to be 70%.

Assuming a 7 bar output pressure, a 100 bar required pressure for the pipeline and a temperature of 70˙ C, we reach an energy consumption of 1.49 kWh/kg H_2 for compression. Rounding this value, we use 1.5 kWh/kg for the 2025 scenario. For 2050, 1.0 kWh/kg is used as the energy consumption for compression (assuming slight improvements in temperature, efficiency and output pressure). These values represent about 2% of the total hydrogen production process energy consumption.

A.2. Salt Cavern Hydrogen Storage

Cost of storage is based on a scaled salt cavern hydrogen storage system that is used at a typical capacity throughout the year. Bunger et al. and Michalski et al. [27, 28] analysed that existing salt caverns are suitable for large-scale hydrogen storage and provide examples on how much can be stored accompanied with a techno-economic analysis. For this research we use numbers from theirs but implement it to our own needs. The same Levelised Cost of Energy methods are used as we do in Sec. 3.1.2. In Table A.1 we see the used values to determine the costs per kg H_2. Operational costs and cost/kg H_2 are based on that the storage system makes one full cycle per year (3733 tons). For 2025, costs were calculated at 1.79 €/kg H_2 and in 2050 1.57 €/kg H_2.

	2025	2050
WACC [%]	3	3
Storage size [tons H_2]	3733	3733
Investment Cost [M€]	107	107
Operational Costs [%]	1.2	1.2
Lifetime [y]	30	40

Table A.1: Levelized cost parameters used for calculating Hydrogen storage costs.

A.3. External Grid Battery Electricity Storage

A.4. Wind Energy

To calculate the wind speed at hub height, two common methods were combined to determine the wind speed from the data: Firstly the logarithmic law was used to calculate wind speed at 60 m (Eq. A.2), secondly this value was used as v_{ref} to calculate hub height wind speed using the power law (Eq. A.3. These methods are more thoroughly explained in [136].

$$v_{60} = v_{ref} \cdot (\frac{ln(60/z_0)}{ln(h_{ref}/z_0)}) \tag{A.2}$$

$$v_{hub} = v_{ref} \cdot (h_{hub}/v_{ref})^a \tag{A.3}$$

where z_0 is the terrain roughness set at 0.0002 for open sea and a is the Hellman's exponent for open sea set at 0.11.

A power curve was used to model power output of the wind turbine from the wind speed data. The power curve chosen for this study is from the Vestas v164-8.0 (8 MW wind turbine) [137]. This model was chosen because in the actual Borssele IV wind park a similar model is going to be built (the 9.5 MW version [83]. These are state-of-the-art wind turbines, we are however looking at future cases so some adaptations were made to the parameters to address for future wind turbines: Mainly opting to increase size and capacity factor.

General Electric (GE) recently unveiled the Haliade-X, a 12 MW turbine with an alleged 63% capacity factor [138]. For the simulations in this research we assumed that the wind turbines are 12 MW as well. The power curve shape was maintained, but adapted to fit to a 12 MW turbine instead of the original 8 MW. Cut-in speed was set at 4 m/s, cut-out speed at 25 m/s, rotor diameter and hub height were set at 220 and 153 m, respectively. This is in accordance with the General Electric Haliade-X model.

With these parameters, a capacity factor was reached of 58.6% in the model. This is for AC power coming out of the turbine (before any transmission or conversion losses). For simplicity reasons, for 2050 these technical parameters were maintained and future technology improvements were incorporated in cost parameters instead, which can be read in the next subsection.

Reference	2025 CAPEX [€]	2025 OPEX [%/year]	2025 LT [years]	2050 CAPEX [€]	2050 OPEX [%/year]	2050 LT [years]
KIC InnoEnergy (2017)	1728	3.7	30	-	-	-
NREL (2018)	2103	5.1	30	1390	6.4	30
Fraunhofer (2014)	3077	2.1	-	1057	2.1	-

Table A.2: Overview of cost projections for offshore wind energy from different sources [62–64].

A.4.1. Economic parameters

For cost parameters it was chosen to compare multiple sources for which the parameters are shown in Table A.2. The sources present different scenarios and from every source the scenario that most closely resembles Borssele IV was picked. In addition, the grid connection costs were subtracted from the costs found, to create a better fit to the case situation.

For the near future case, we can find reporting on future off-shore wind generation done by InnoEnergy and BVG Associates [62]. This report is preferred because it is European-specific and specialized on off-shore wind. We can derive CAPEX and OPEX costs and identify different costs of components, as well as the net capacity factor for 2025. The 12-A-25 scenario (12 MW turbines-near coast-2025) was picked as a reference because it has the closest resemblance to the proposed wind turbine in this research. The costs for the electrical array are disregarded because we want to distinguish between the hydrogen and the electrical grid and incorporate those costs there. Then, a CAPEX was found of 1728 €/kW and OPEX of 3.7 % yearly.

As projections after 2030 were not available in the other report, I use the 2018 updated NREL Annual Technology Baseline (ATB) database for the 2050 scenario [64]. The TRG-1 Low scenario was chosen for being most consistent with the results in the other report and this research. Here, we reach a € 1390 investment cost (without grid connection again) and 6.4% o&m costs. The O&M costs seem very high compared to the earlier report. Also the lifetime is assumed to stay constant at 30 years.

With these technical and economical parameters, an LCOE of 0.029 €/kWh is obtained in 2025, and 0.019 in €/kWh in 2050. This is on the optimistic side of predictions, but within range of realism. Please note that only the wind turbine itself is considered here, so no transformer, transmission or other losses that happen outside the wind turbine. These factors are considered in other parts of the model.

A.5. Batteries

A.6. Fuel Cells

A.7. Hydrogen Grid

Characteristic (2025)	BEV batteries [1,2]	LFP-LTO [2,3,4,5, 6]	Vanadium Redox [3,7]
Investment Cost [/kWh] (incl BoP cost)	400	1142	698
O&M Cost [%]	0.6	0.6 (?)	2
Efficiency (roundtrip, with 0.95 inverter eff)	0.73	0.88	0.67
Lifetime (calendar)	8	15	25
Lifetime (cycles)*	1332 (SOH = 80%)	10000 (SOH = 80%)	13000 (SOH = 80%)
Usable SoC [% of capacity]	80	90	100

Table A.3: **Three battery technologies compared for stationary storage usage**

Object	**Capacity**	**Unit Costs**	**TC (Now) [1000 €]**	**TC (2050) [1000 €]**
Investment Costs	3.5 MW	150 / 30 €/kW	525	105
O&M costs	3.5 MW	5%		
Back-up Fuel cell generator				
Investment Costs	1.008 MW	150 / 30 €/kW	151200	30240
O&M costs	3.5 MW	5%		

Table A.4: Fuel Cell system costs. Numbers derived from [69]

Property	**Hydrogen (H_2)**	**Natural Gas (mix)**
Energy content [MJ/Nm^3 (HHV)]	12.7	35.17
Density [kg/Nm^3]	0.081	0.841
Viscosity [$Pa \cdot s$]	8.8e-6	10.2e-6
Average velocity $\bar{u}$ [m/s]	**60**	**20**

Table A.5: Table showing main differences in characteristics of Hydrogen and Natural gas. Average velocity is approximated for same energy content. Constructed from [35, 36]

Connection Service	
Capacity [Nm^3/h]	**Cost [€ /month]**
40-65	21.22
65-100	30.94
100-160	58.75
160-250	72.90
250-400	102.32
400-650	138.15
650-1000	186.25
1000-1600	225.53
1600-2500	283.91
2500-4000	412.87
4000-	412.87

Transport Service	**[/month]**
Cost per connection	72.29
Capacity [per Nm^3/h]	1.71

Table A.6: Tariffs for grid connection services for natural gas grid for large users in Amsterdam. Prices are for 2018 ex. taxes. Based on [105]

STCA	
Number of connections	2
Maximum kg H2 required [kg/h]	348
Energy equivalent [kWh/h]	13714
Natural Gas equivalent [Nm^3/h]	1403.9

Table A.7: Model results for STCA h2 grid requirements for near-future hydro-electric case.

Costs breakdown	**Amount/Type**	**Month [ ]**	**Year [ ]**
Connection Service: Capacity	1000-1600 Nm^3/h	225	2706
Connection Cost (Transport Service)	2	144.58	1734
Capacity Cost (Transport Service)	1403 Nm^3/h	2400	28807
Total		**2770**	**33250**

B
Extra results

B.1. Open Combined System
B.2. Alternative Designs
B.3. Office cases

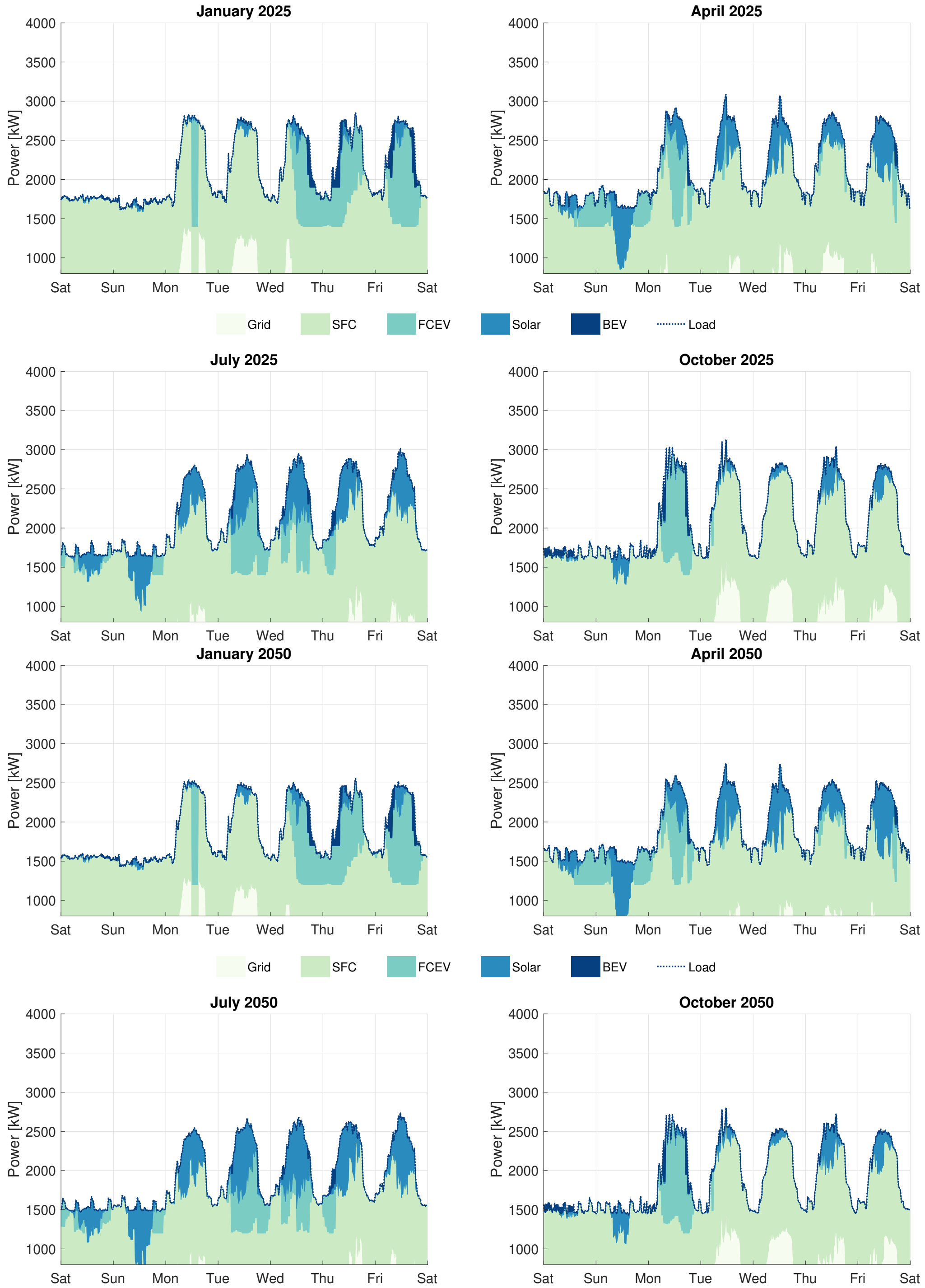


Figure B.1: **STCA Combined - Open case. Load Profile Plots for every season showing total load and local generator power on a weekly timescale.**

Type	Unit	Near Future (2025)				Mid Century (2050)			
	[-]	Q	CC [k€/y]	OMC [k€/y]	TC [k€/y]	Q	CC [k€/y]	OMC [k€/y]	TC [k€/y]
Solar	kW	1176	49	23.9	72.8	1176	26.4	11.9	38.3
Wind	kW	5800	673.7	200.4	874.1	4800	340.4	133.4	473.8
Electrolyser	kW	6600	212.9	63.4	276.3	4400	44.9	8.8	53.7
Compression, water treatment	kg/h	94	64.3	30.9	95.2	85	24.9	6.2	31.1
Salt Cavern	tonnes H2 Capacity	3733	0	291.3	291.3	3733	0	217.9	217.9
H-Grid	Nm^3/h NG	650	0	17.4	17.4	400	0	15.1	15.1
E-Grid	MW Connection Capacity	10	0	216.2	216.2	10	0	216.2	216.2
Stationary Fuel Cell	kW	1450	121.5	18.6	140.1	1400	32.1	7	39.1
FCEV	kW of systems	17800	93.7	7.1	100.8	15700	27.7	4.2	31.9
BEV	kWh of batteries	4440	13.6	4.3	17.8	5600	11.8	3.9	15.7
Bi-Directional Chargers	# of 2-point chargers	37	53	17.6	70.6	28	16.4	7	23.4
FCEV Discharge Infrastructure	# of 4-point connectors	45	24.1	14.4	38.5	40	10.7	6.4	17.1
Heat Pumps	kW	3300	108.7	11.3	120	2970	97.8	10.2	108
Storage Difference H2	kg	4612	0	-17.8	-17.8	523	0	-1.2	-1.2
External Charging costs BEVs	MWh	84	0	20.9	20.9	33	0	4.9	4.9
Total Costs			**1414.6**	**919.8**	**2334.3**		**633.1**	**652**	**1285.1**

Table B.1: **Cost tables of Combined System Design for near-future and mid-century scenarios with use of heat pump.**

Type of LCOE	**2025 [/ kWh]**	**2050 [/ kWh]**
$LCOE_{Solar}$	0.071	0.031
$LCOE_{Wind}$	0.03	0.024
$SLCOE_{Wind}$	0.046	0.043
$SLCOE_{H2}$ [€/kg]	3.247	2.267
$SLCOE_{BEV}$	0.082	0.058
$SLCOE_{FCEV}$	1.815	0.986
$SLCOE_{SFC}$	0.357	0.2
$SLCOE_{e,STCA}$	0.178	0.1
$SLCOE_{Q,STCA}$	0.056	0.045
$SLCOE_{STCA}$	0.09	0.061
$SCOE_{STCA}$ [€ / m^2/year]	22.2	13.5

Table B.2: System Levelized Cost end results for Combined scenarios with boiler and sfc used for heating in Near-Future and Mid-Century

Type of LCOE	**2025 [/ kWh]**
$LCOE_{Solar}$	0.071
$LCOE_{Wind}$	0.03
$SLCOE_{Wind}$	0.046
$SLCOE_{H2}$ [euro/kg]	3.591
$SLCOE_{H2SLCOE}$ (HHV)	0.091
$SLCOE_{BEV}$	0.478
$SLCOE_{FCEV}$	0.295
$SLCOE_{SFC}$	0.248
$SLCOH_{STCA}$	0.052
$SLCOE_{SaltCavern}$	1.79
$SLCOE_{STCA}$ (weighted average)	0.11
$SLCOE_{STCA}$ (TC/EC)	0.11

Table B.3: System Levelized Cost end results for Combined scenarios in Near-Future and Mid-Century when using FCEVs and BEVs as a priority.

		Near Future (2025)				Mid Century (2050)			
Type	**Unit** [-]	**Q**	**CC** [k€/y]	**OMC** [k€/y]	**TC** [k€/y]	**Q**	**CC** [k€/y]	**OMC** [k€/y]	**TC** [k€/y]
Solar	kW	1176	49	23.9	72.8	1176	26.4	11.9	38.3
Stationary Fuel Cell	kW	1400	117.3	17.9	135.2	1200	27.5	6	33.5
FCEV	kW of systems	17800	107.3	35.6	142.9	17300	40.8	22.9	63.7
BEV	kWh of batteries	4200	13.2	2.4	15.6	6000	12.6	2.5	15.1
Bi-Directional Chargers	# of 2-point chargers	35	42.2	42	84.2	30	12	11.9	23.9
FCEV Discharge Infrastructure	# of 4-point connectors	45	24.1	14.4	38.5	44	11.8	7	18.8
Heat Pumps	kW	3300	108.7	11.3	120	2970	97.8	10.2	108
External Charging costs BEVs	MWh	92	0	5.9	5.9	65	0	3.1	3.1
Bought H2 from grid	tonnes	653	0	1691.6	1691.6	537	0	1004.4	1004.4
Bought E from grid	MWh	4159	0	266.2	266.2	3749	0	180	180
Total Costs			**461.9**	**2111.2**	**2573.1**		**228.9**	**1260**	**1488.9**

Table B.4: Cost tables of Combined System Design for near-future and mid-century scenarios with an open system and emphasis on hydrogen

Type	Unit	Near Future (2025)				Mid Century (2050)			
		Q	CC	OMC	TC	Q	CC	OMC	TC
	[-]		[k€/y]	[k€/y]	[k€/y]		[k€/y]	[k€/y]	[k€/y]
Solar	kW	400	16.7	8.1	24.8	300	6.7	3	9.8
Wind	kW	1628	189	56.3	245.3	706	50.1	19.6	69.7
Electrolyser	kW	2200	71	21.1	92.1	2200	22.4	4.4	26.8
Compression, water treatment	kg/h	32	21.6	10.4	32	15	4.6	1.2	5.7
Salt Cavern	tonnes H2 Capacity	3733	0	103.5	103.5	3733	0	44.3	44.3
H-Grid	Nm^3/h NG equivalent	160	0	6.3	6.3	65	0	3.5	3.5
E-Grid	MW Connection Capacity	0	0	0	0	0	0	0	0
Stationary Fuel Cell	kW	250	21	3.2	24.2	100	2.3	0.5	2.8
FCEV	kW of systems	3200	78.4	1.3	79.7	2300	26.4	0.6	27
BEV	kWh of batteries	0	0	0	0	0	0	0	0
Bi-Directional Chargers	# of 2-point chargers	2	2.9	1	3.8	6	3.5	1.5	5
FCEV Discharge Infrastructure	# of 4-point connectors	8	4.3	2.6	6.8	6	1.6	1	2.6
Airco	kW	450	7	3.2	10.2	275	4.3	2	6.3
H2 Boilers	kW	329	1.5	0.4	2	219.0963	1	0.3	1.3
Storage Difference H2	kg	-1399	0	4.3	4.3	-5446.4968	0	11.9	11.9
External Charging costs BEVs	kWh	0	0	0	0	0	0	0	0
Total Costs			**413.3**	**221.6**	**635**		**122.9**	**93.8**	**216.7**

Table B.5: **Cost tables of Hydro-Electric Office Design for near-future and mid-century scenarios**

Type	Unit	Near Future (2025)				Mid Century (2050)			
		Q	CC [k€/y]	OMC [k€/y]	TC [k€/y]	Q	CC [k€/y]	OMC [k€/y]	TC [k€/y]
	[-]								
Solar	kW	400	16.7	8.1	24.8	300	6.7	3	9.8
Wind	kW	569	66.1	19.7	85.8	230	16.3	6.4	22.7
E-Grid	MW Connection Capacity	2	0	44.9	44.9	2	0	44.9	44.9
Stationary Battery (BESS)	kWh	30	1.1	0.1	1.1	10	0.2	0	0.2
FCEV	kW of systems	9600	46	3.8	49.9	100	1.8	0	1.9
BEV	kWh of batteries	7200	108	6.9	114.9	3300	23.7	2.3	26
Bi-Directional Chargers	2-point chargers	60	86	28.5	114.5	17	10	4.3	14.2
FCEV Discharge Infrastructure	4-point connectors	24	12.9	7.7	20.5	1	0.3	0.2	0.4
Heat Pump	kW	780	36.7	3.8	40.6	454	15	1.6	16.5
External Grid Storage	MWh	196	0	20.5	20.5	30	0	1.6	1.6
External fueling costs FCEV	tons	16	0	97.4	97.4	1	0	4.4	4.4
External Charging costs BEVs	MWh	1639	0	409.9	409.9	646	0	96.9	96.9
Difference in BESS storage	MWh	0	0	0	0	0	0	0	0
Total Costs			**373.4**	**651.2**	**1024.7**		**73.9**	**165.6**	**239.6**

Table B.6: **Cost tables of Office All-Electric System Design for near-future and mid-century scenarios.**

Type	Unit	Near Future (2025)				Mid Century (2050)			
		Q	CC	OMC	TC	Q	CC	OMC	TC
	[-]		[k€/y]	[k€/y]	[k€/y]		[k€/y]	[k€/y]	[k€/y]
Solar	kW	400	16.7	8.1	24.8	300	6.7	3	9.8
Stationary Fuel Cell	kW	250	21	3.2	24.2	250	5.7	1.3	7
FCEV	kW of systems	3000	63.4	1.2	64.6	1700	8.7	0.5	9.2
BEV	kWh of batteries	1800	43.3	1.7	45.1	1700	8.3	1.2	9.5
Bi-Directional Chargers	# of 2-point chargers	15	21.5	7.1	28.6	9	5.3	2.3	7.5
FCEV Discharge Infrastructure	# of 4-point connectors	8	4.3	2.6	6.8	5	1.3	0.8	2.1
Heat Pumps	kW	780	25.7	2.7	28.4	454	15	1.6	16.5
External Charging costs BEVs	MWh	759	0	189.9	189.9	234	0	58.4	58.4
Bought H2 from grid	tons	52	0	147	147	9.2	0	17.3	17.3
Bought E from grid	MWh	1922	0	123.1	123.1	1264	0	60.7	60.7
Total Costs			**195.9**	**486.6**	**682.5**		**51.1**	**146.9**	**198**

Table B.7: **Cost tables of office Combined System Design for near-future and mid-century scenarios with vehicle usage as a priority.**

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