THESIS FOR THE DEGREE OF LICENTIATE OF ENGINEERING

Infrastructural requirements for indirect and direct electrification of road transportation

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Abstract

This thesis analyzes the integration of electricity and transportation systems for a future in which transportation is increasingly electrified. The focus is on exploring the infrastructures required for the indirect electrification of heavy transportation and the direct electrification of passenger vehicles. The work is motivated by both the increased number of electrified vehicles and a lack of knowledge as to the impacts on the electricity system. The papers included in this thesis develop and apply two different energy systems models.

The first model, which is a cost-minimizing, linear, optimization model for hydrogen refueling stations, was developed to compare the cost-efficiencies of three electrolysis-based systems for providing hydrogen to refueling stations for heavy road transportation: a decentralized, off-grid system for hydrogen production from wind and solar power; a decentralized system connected to the electricity grid; and a centralized grid-connected system with hydrogen transported to refueling stations. The results show that for most of the studied geographic regions, the decentralized grid-connected system gives the lowest costs for hydrogen delivery, while the standalone system entails higher hydrogen production costs. In addition, the centralized system entails lower costs for production and storage than the grid-connected decentralized system, although the additional costs for hydrogen transport increase the total cost.

The second model, the REGAL model, is an open data-based model designed to create a synthetic representation of a low-voltage (LV) grid for a country-size geographic area. This thesis presents the results of calibration and validation against real-world data for the synthetic grid generated by the model. For a region with area >350 km^2, an average deviation from real-world data of less than ±10% was achieved. For an average area of 1 km^2, the error was 44.5%, which means that the model is not suitable for analysis at this geographic scale. However, the level of accuracy is deemed sufficient for initial estimations of hosting capacity for larger geographic areas, such as a region or a country.

The REGAL model is used to investigate power system violations linked to exceeding the operational limits (thermal capacity and voltage magnitude) of the Swedish LV grid when electric vehicle (EV) charging is added at different EV shares of the passenger vehicle fleet. Three charging strategies are assumed: direct; cost-minimized (based on an electricity spot price); and mixed charging (a mix of the first two charging strategies). The results show that the number of violations increases with the fleet share of EVs, regardless of the charging strategy, albeit slowly at first. As the fleet share of EVs increases, the number of violations introduced with each additional EV is higher. Most violations occur in areas with a high population density. The charging strategy affects both how often and to what extent the operational limits of the grid are exceeded. On average, the direct charging strategy has a higher frequency (i.e., how often limitations are exceeded) and amplitude (i.e., by how much the limits are surpassed) of violations compared to the other charging strategies. However, when EVs follow the cost-minimizing charging strategy, a stronger coincidence is seen for the EV charging, yielding higher peaks of the maximum load in some areas and, thereby, a higher peak amplitude of power system violations, as compared to direct charging.

Keywords: *Hydrogen supply, hydrogen infrastructure, low-voltage grid, home charging, electric vehicles, charging strategies, hosting capacity*

List of publications

The thesis is based on the following appended papers, which are referred to in the text by their assigned Roman numerals:

I. T. Lundblad, M. Taljegård and F. Johnsson. “Centralized and decentralized electrolysis-based hydrogen supply systems for road transportation – A modeling study of current and future costs”. *International Journal of Hydrogen Energy*, vol Volume 48, Issue 12, pp. 4830-4844, 2023, doi: 10.1016/j.ijhydene.2022.10.242.

II. T. Lundblad, M. Taljegard, N. Mattsson, E. Hartvigsson & F. Johnsson. “An open data-based model for generating a synthetic low-voltage grid to estimate hosting capacity”. In manuscript.

III. T. Lundblad, M. Taljegard, N. Mattsson, P. Romero Del Rincón & F. Johnsson. ”Impacts of electric vehicle charging strategies on low-voltage electricity grids”. In manuscript.

Therese Lundblad is the principal author of **Papers I–III** and performed the modeling and analysis for all three papers. Professor Filip Johnsson contributed with discussions and editing to **Papers I–III**, and Dr. Maria Taljegård contributed to the method development in **Papers I–III**, as well as with editing and discussions for all three papers. Dr. Niclas Mattsson contributed to the method development and discussion in **Papers II** and **III**. Dr. Elias Hartvigsson contributed to the method development and discussion in **Paper II**. Pablo Romero Del Rincón contributed to the method development of **Paper III**.

Acknowledgments

This thesis was written to the steady groove of the artists of STAX records and in the process of writing it, I have lost both my favorite mittens and several hours of sleep due to the distraction it provided. However, I am glad to present you with the final product, both because I am proud of the personal journey it represents and because of the joy the people involved and the memories made have brought me.

Behind every researcher in the making, there is a team of people supporting and guiding the work in different ways without whom the work would not be possible. My team is led by my supervisors Maria Taljegård and Filip Johnsson. For that, I would like to express my gratitude. Your guidance and insights have been crucial in every part of this work, from formulating research questions to developing models and writing academic papers. The combination of Maria's knowledge in modeling energy systems and transport, and Filip's contacts and experience makes sure that our research is kept relevant and progressing. Further, having supervisors and mentors with whom to discuss your research constructively is crucial to creating a supportive environment in which new ideas can grow. Which brings me to another collaborator in this work, Niclas Mattson. Niclas, it has been a true pleasure to discuss and develop a model together with you. Gaining your perspective on my work has developed my abilities as both a modeler and a researcher. A thank you to Elias Hartvigsson, on which work the development of my modeling builds, for creating a stable platform from which we could leap into new knowledge. And to the rest of my research group for creating a network of friendly faces ready to support each other on a bad day, week, or month. I look forward to more fika breaks and ice cream runs in the coming years together with you!

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Therese Lundblad

Varberg, 3rd of April, 2024

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1. Introduction

Transportation accounts for almost 30% of the energy demand in the European Union (EU), and its energy supply is currently dominated by fossil fuels [1, 2]. Towards meeting the EU climate targets, reducing the levels of emissions linked to transportation represents a key challenge, given that the transportation sector accounts for 37% of global greenhouse gas (GHG) emissions and about 25% of European GHG emissions (excluding international maritime emissions) [3–5]. The increasing electrification of the transportation sector has been identified as a crucial step towards achieving climate targets [5, 6]. Two main pathways exist for the electrification of transport: indirect electrification, and direct electrification. Indirect electrification occurs when electricity is used to produce a so-called *electrofuel*, which is used in the vehicle, either through converting it back to electricity and employing an electric motor or by using the electrofuel in an internal combustion engine (ICE). Typically, a fuel cell in combination with an electric motor is preferred over an ICE due to its higher efficiency. Direct electrification of transportation means that electricity is charged directly to the vehicle and stored in a battery. This stored energy is subsequently used to propel the vehicle using an electric motor in a battery electric vehicle (BEV). Direct electrification typically has a higher efficiency, while indirect electrification has the advantages of faster refueling time, greater range, and the possibility for long-term storage of fuels [7, 8]. Furthermore, a drawback associated with direct electrification is the larger demand for battery capacity, for which material extraction and processing face challenges regarding environmental burdens and resource scarcity. Typically, direct electrification is the preferred method due to its substantially higher efficiency. However, for vehicle segments where this is not possible (for example, due to restrictions related to weight, range or charging time), indirect electrification via hydrogen (the simplest electrofuel) is a complementing technology, enabling transport without tailpipe emissions in situations where direct electrification is not an option [8, 9].

The road transportation demand can categorized according to what is transported (i.e., passengers or goods) or the type of vehicle used (bicycle, car, bus, light-duty vehicle, heavy-duty vehicle, etc.). There are different challenges associated with different demand segments. For example, both buses and trucks are heavy vehicles, but for city buses and short-haul trucks, direct electrification has been introduced to some degree, while for long-range buses and heavier or long-range trucks, commercially viable options are currently lacking. For heavy road transport, electrification is occurring slowly, with electric buses making up 9% and electric trucks making up only 0.5% of the vehicles sold in Europe in Year 2022 [10]. To decarbonize heavy road transport, both direct and indirect electrification are needed [10]. In addition, increased efficiency related to the flow of goods is needed to decarbonize this sector, while fulfilling other sustainability goals [10]. Indirect electrification using hydrogen as an energy carrier has been identified as a possible solution in the transition to a sustainable transportation sector, especially for heavy freight transportation [9, 11–13]. Although hydrogen is scarcely used for transportation at present, it is employed extensively in industry. Hydrogen can be produced from a variety of sources, with steam methane reforming (SMR) of natural gas currently accounting for the largest share of production, followed by oil reforming and coal gasification. These processes are associated with significant GHG emissions. However, when it comes to hydrogen use in the energy transition, water electrolysis using electricity from carbon-neutral generation is an option [14–16].

To enable a shift to hydrogen-fueled heavy transport, it will be crucial to introduce a network of hydrogen refueling stations for which the hydrogen supply is both reliant and efficient. In the EU, the regulation relevant to the deployment of alternative fuels infrastructure states that hydrogen refueling stations should be deployed every 200 km in the trans-European transport network (TEN-T) [17]. The supplying of hydrogen to refueling stations has been evaluated in several studies [8, 18–28]. Hydrogen production can be located at the site of the refueling station, i.e., in a decentralized system, or it can be centrally located in combination with a distribution system that transports hydrogen from the production site to the refueling stations [21]. A global overview of the current trend in relation to the installation of hydrogen refueling stations has been carried out by Samsun et al. [8]. They have shown that the number of hydrogen refueling stations is growing, although they conclude that an increase in the rate of new installations is needed to meet the target numbers (for example, the previously mentioned EU target of refueling stations placed every 200 km) in the coming years. For hydrogen that is produced through electrolysis, the production cost is heavily dependent upon the cost of electricity [28], and estimates of the levelized cost of hydrogen (LCOH) available in the literature (e.g., [19, 25]) are based on historical electricity price data. A future electricity system with high shares of variable renewable electricity (VRE) production might generate more-severe fluctuations in electricity prices, thereby altering the conditions for hydrogen production [29]. It is, therefore, relevant to investigate the conditions for hydrogen production in a future electricity system with larger shares of non-dispatchable electricity generation.

For passenger transport, both the energy demand and the levels of GHG emissions are dominated by car usage. In addition to a shift to less-carbon-intensive transportation modes (such as walking, cycling, and public transport), there is a need for measures that decrease the GHG emissions from vehicles, if we are to meet the GHG emissions targets [5]. There is an increasing share of electric vehicles (EVs) in the passenger vehicle fleet in several countries [6]. In 2022, EVs accounted for 22% of new registrations of passenger vehicles in Europe when considering both BEVs and plug-in hybrid electric vehicles (PHEVs) [6]. This development has been supported by various subsidies and the trend is likely to continue [5] with, for example, the EU phasing out ICE vehicles [30]. As the number of EVs increases, the loads from EVs charging through the electricity grid increase.

For vehicles that are mainly powered by an on-board battery, electricity needs to be supplied by a charging infrastructure. This charging infrastructure may be needed at the home location, at work, or in public areas and needs to be supported by the electricity grid. Traditionally, electricity grids were built to distribute electricity to consumers with a more or less inflexible load. As more sectors are electrified, including the transportation sector, and electricity production becomes increasingly decentralized and more-volatile (from increasing shares of wind and solar power), greater stress is exerted on the local electricity grid and on its operational ability to connect production and demand in both space and time. Several studies have been conducted on passenger EVs and their impacts on electricity systems (for reviews, see Nazari-Heris et al. [31], Kumar et al. [32], and Nour et al. [33]). For example, Hedegaard et al. [34] have assessed how large-scale implementation of EVs would influence the northern European electricity systems. They have shown that enabling intelligent EV charging and discharging can support variable renewable electricity production, although they conclude that the effects of EVs on electricity systems will vary across different countries. The impacts of EV charging on electricity generation and storage have been investigated using energy systems modeling by Taljegard et al. [35], who reach the conclusion that controlled charging of EVs can reduce investments in peak power capacity, reduce the need for storage technologies, and stimulate increased shares of solar and wind power generation. However, few studies have included the capacities of distribution grids, which means that it is not considered if the distribution grid can supply the electricity needed for the studied rates of EV charging. For those studies in which the distribution grid has been considered, the geographic scope is typically very narrow (such as in the study of a distribution grid in Sweden by Luthander et al. [36]). Thus, there is a need to study on a general level the extent to which the distribution grid has the capacity to supply the electricity needed for the charging of EVs.

1.1 Aim and research topic

The overall aim of the thesis is to analyze the integration of electricity and transportation systems as transportation becomes increasingly electrified. This thesis focuses on exploring the infrastructures required for the indirect electrification of heavy transportation and the direct electrification of passenger vehicles. The work is motivated by both the increase in the number of electrified vehicles in combination with further policy incentives that support the development and a lack of knowledge as to how this affects the electricity system.

This thesis is based on the three appended papers (**Papers I–III**). **Paper I** investigates the infrastructure for indirect electrification and aims to answer the research question:

- How do centralized and decentralized hydrogen supply systems, as well as standalone and grid-connected systems compare in terms of their cost-efficiency?

Papers II and **III** investigate the infrastructure for direct electrification, with the focus on a low-voltage (LV) grid and its capacity to host large-scale home charging of EVs, so as to answer the research questions:

- How can the LV grid of a larger area, such as a country, be modeled using open data?
- What types of issues are likely to occur with the LV grid due to the home-charging of electric vehicles?
- How severe are the impacts of these issues on the LV grid likely to be?
- When are exceedances of grid capacity due to EV charging likely to occur?
- What are the impacts of different EV charging strategies on the LV grid?

1.2 Contents of the papers

Paper I describes comparisons of different electrolysis-based systems for supplying hydrogen to refueling stations. Previous studies have not compared different supply systems using the same methodology. Therefore, centralized and decentralized electricity grid-connected systems are compared alongside a standalone system in a cost-minimizing linear optimization model.

Paper II develops and applies a model for residential LV grids that generates a synthetic LV grid from open data. This model can be used to run grid simulations for areas for which grid capacities are not publicly available. For the few similar models that exist, validation data are usually not publicly available, which means that the accuracy and transferability of the model results are unsatisfactory. Therefore, the model used in this work is calibrated and validated against real-world data, and the accuracy of the generated grid is discussed in this paper.

Paper III uses the model developed in **Paper II** to assess how different charging strategies influence the issues that are likely to appear in LV grids as the EV fleet share expands. When these issues occur and their severity levels are also evaluated. Compared to previous studies, this represents a deeper analysis of by how much, and how often, the operational limits of the LV grid are exceeded.

The work presented in this thesis was carried out in the period of 2021–2024.

1.3 Structure of the thesis

The thesis is based on the three amended papers and this introductory essay. Chapter 2 describes electricity systems and modeling, as well as relevant previous work done on the topic. Chapter 3 explains the models used in this work and the contexts in which they evolved. Chapter 4 presents and discusses the key results from this work. Chapter 5 presents the main findings, while Chapter 6 identifies areas for future work.

2 Background and related work

This section provides background information on: the current electricity grid (Section 2.1); modeling of the electricity system (Section 2.2); the results of previous research related to hydrogen refueling stations (Section 2.3); and the modeling of distribution grid impacts from the charging of EVs (Section 2.4). For Sections 2.1 and 2.2, a general overview is provided, while Sections 2.3 and 2.4 focus on identifying what relevant previous research has been carried out on the topic.

2.1 The electricity grid

The basic layout of an electricity system involves electricity generation that is connected to end-consumers via a grid that consists of power lines, cables, and transformers. This electricity grid can be delineated according to different voltage levels, as different voltage levels in the grid serve different purposes. Figure 1 shows an overview of the voltage levels in the different parts of the electricity grid. Different terms are used for some parts of the power system, meaning that for some parts, more than one term is included in the figure. The transmission network transports a large amount of electric energy over long distances, from the large centralized electricity generators to the sub-transmission network, also known as the *regional grid* [37]. This transmission is carried out at the highest voltage levels in the grid, to reduce losses [37]. The sub-transmission grid connects the transmission grid to the distribution grids, so its function is similar to that of a transmission grid, although due to techno-economic factors, transmission occurs at a lower voltage level [38]. This part of the grid is also the connection point for intermediate-size electricity producers [37]. The sub-transmission grid typically has more than one connection to the transmission grid [38]. Distribution grids, sometimes referred to as *local grids*, have the primary purpose of distributing electricity from the sub-transmission grid to end-users [38]. It also hosts some small-scale electricity generation [37]. The distribution grid is mostly operated as a radial network, meaning that there is only one path from the higher voltage level to the end-user [38]. The primary part of the distribution grid (the higher voltage levels of the distribution grid) is commonly referred to as the *medium-voltage* (MV) grid. Some actors include the sub-transmission grid in the MV grid, while others regard it as part of the high-voltage grid. End-users have different power demands and are, therefore, connected at different voltage levels to the distribution grid [38]. Simply put, the higher the power demand, the higher the voltage level at which the connection is made. Depending on the power demand at a specific location, electrified transportation can connect to different parts of the distribution grid. To determine if the distribution grid has the capacity to handle this new load, further analysis is needed. The study of direct electrification of passenger vehicles included in this work models the LV grid. This is because it focuses on charging strategies for home-charging of EVs, and residential homes being connected to the electricity grid on the LV level.

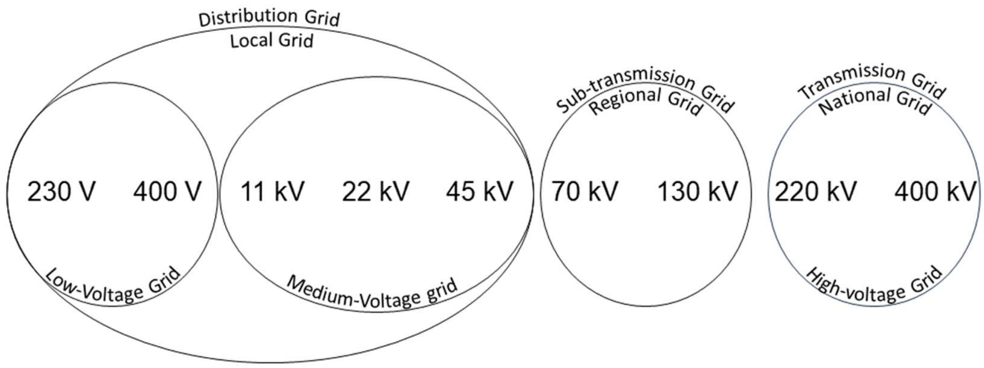

Figure 1. *Schematic overview of the voltage levels in the different parts of the electricity grid.*

2.2 Energy systems modeling

Energy systems modeling is a field that is dedicated to understanding how different parts of energy systems can interact and develop. This includes both studies of future demands and the supplies of different technologies and sectors. Ringkjøb et al. [39] reviewed 75 currently used modeling tools for studying energy and electricity systems (where *energy system* is a broader term that includes energy carriers and energy demands other than for electricity), describing a wide range of geographic and temporal resolutions, purposes, and methodologies. Typical inputs are the technical properties of the electricity supply and demand, the efficiencies of energy conversion, and the costs of components [40]. Some common purposes of the modeling efforts include studying sector coupling, interactions between different emerging technologies, cost-optimal solutions to supply a given demand, and studying the likely evolution over time of the different energy systems [40]. Common methodologies used include linear optimization (usually with the goal of minimizing the total cost), energy system simulation (typically, forecasts), electricity market models, and qualitative modeling [40].

Power system analysis (or power grid analysis) is a related tool for considering the main aspects of power system operation. Modeling usually revolves around assessing electricity grids under either steady-state (or near-steady-state) operation or during disturbances or faults [41]. Typically, a power flow analysis is used in which the currents (i.e., the active and reactive power flows) and voltages, and other relevant qualities of the power, in different parts of an electricity system are calculated [41]. A full power flow analysis entails a complex, non-linear set of equations, which increases the difficulty associated with solving the set of equations that it includes [41]. Simplifications, such as assuming that the load is balanced between phases and that the power supply originates from a single source, enable a linear set of equations to be representative and, therefore, create a system that is easily solvable with reasonable demands on computational resources [38]. Compared to energy systems modeling, which typically has a broad geographic scope, such as an entire continent, power system analysis typically studies a small region within a country.

2.3 Supplying hydrogen to refueling stations

Tang et al. [19] compared hydrogen production at refueling stations in Sweden that are run in island mode (i.e., not connected to the electric grid), using dedicated wind and solar power units with a similar, albeit grid-connected, system; and they concluded that grid connection tends to achieve a lower LCOH. However, since Tang et al. [19] assumed a constant hydrogen demand using historical spot market prices for the electricity supplied to the electrolyzer, these prices may not be representative of a future electricity system that has a higher share of VRE.

An economic analysis of a standalone wind-powered system for supplying hydrogen to refueling stations in Sweden has been conducted by Siyal et al. [18]. They conclude that such a setup could help reach the goal of a fossil-free transport sector in Sweden, although the setup investigated was not compared with other systems for hydrogen production. Göcek and Kale [23] used a techno-economic analysis to assess the feasibility of a hydrogen refueling station powered by either a wind-photovoltaics (PV)-battery or wind-battery system located on the island of Gökçeada in Turkey. They pointed out that such systems could be feasible for the chosen site and that a hybrid wind-PV-battery system yields a lower LCOH than a wind-battery system [23]. Janssen et al. [20] studied off-grid hydrogen production facilities in different European countries. They found that electrolyzer systems that supply electricity using both wind power and solar PV to power an electrolyzer have the lowest costs in nearly all of the countries studied. They further conclude that with projected cost reductions, off-grid hydrogen production from renewable sources could yield a cost similar to that of conventional hydrogen production [20]. That study did not target the transport sector, and hydrogen compression and storage were not included. Furthermore, the study did not consider hydrogen production systems that are connected to an electric grid with renewable electricity. Nistor et al. [25] performed a techno-economic study of a hydrogen refueling station in the UK, focusing on the short-to-medium-term representation of technology and costs, comparing a wind-powered system run in island mode with a similar grid-connected system. For the grid-powered system, a fixed electricity price was used. They found that the grid-connected and standalone wind-powered systems had a similar LCOH; however, the grid-connected system had a larger share of the cost as operational costs, while the island-mode system had a larger investment cost. They expressed a need for further investigation of the tradeoffs that occur between installed wind power capacity and hydrogen storage size [25].

Ulleberg and Hancke [26] studied hydrogen production in a Norwegian context using two small-scale production cases that employ water electrolysis. In the first case, local hydropower was used to power an electrolyzer onsite, while the second case looked at a hydrogen refueling station, comparing on-site hydrogen production with a centralized supply system. They observed lower costs for hydrogen production in the second case, due in large extent to increased utilization [26]. In that study, optimization was not performed and no estimations were made of how their defined cases would be affected by changes in the electricity system composition and any consequent changes in electricity prices.

Although the abovementioned studies have provided valuable insights into the cost of hydrogen production for the transport sector, studies that evaluate multiple hydrogen supply systems are lacking. For situations in which there is more than one supply system, the studies have been limited to modeling their costs using historical electricity price profiles.

2.4 Modeling distribution grid impacts from electric vehicles

Reviews of the methods and tools for estimating the numbers of EVs and amounts of solar PV that can be hosted by the capacities of current LV grids – hereinafter referred to as the *hosting capacity* – have been presented by Umoh et al. [42] and Carmelito and Filho [43]. An additional review of the calculations for hosting capacity has been presented by Abideen et al. [44]. All of these publications describe methodologies for the evaluation of hosting capacity and their strengths and weaknesses. The reviews have characterized previous studies based on the types of methodologies used for predicting how new loads influence electricity grids. Three types of methodologies for adding new loads have been identified: deterministic simulations; stochastic methodologies; and time-series methods [43]. In the reviews of Umoh et al. [42] and Mulenga et al. [45], the evaluation criteria for the determination of hosting capacity have been addressed. Both studies have concluded that most studies of hosting capacities have used the same three performance indices: voltage magnitude; line or cable loading; and transformer loading. Some studies have included additional evaluation criteria, such as power loss and voltage imbalance [46–49].

The three methods used for the evaluation of hosting capacity assume that the capacity of the investigated grid is known. If the real grid capacities are unknown, an estimation of current grid capacities is needed. Currently, it is often difficult to have access to grid capacities relevant to a larger geographic area, since the operation of electricity grids, especially distribution grids, is typically split among multiple actors, and national security restrictions limit access to the data. One option is to gain access to the grid capacities for a smaller area, so as to perform a case study and subsequently extrapolate the results to a larger area [36]. Due to the lack of real grid capacities, some studies (e.g., Veldman et al. [50]) have used typical grids and extrapolated the results to larger areas. An alternative method is to develop a synthetic grid based on data regarding the number of customers in an area and the grid design principles, and thereafter use that grid to analyze the hosting capacities for EVs and solar PVs [51–53], applying different EV charging strategies.

2.4.1 The impacts of EV charging strategies

The charging of EVs can be unidirectional or bidirectional. Bidirectional charging means that electricity can also be transferred from the vehicle to the household or to the electricity grid [also known as V2X if referring to feeding electricity back into any type of system, or vehicle to grid (V2G) if feeding back to the electricity grid]. Furthermore, charging can be controlled or uncontrolled. Uncontrolled charging of EVs, i.e., typically corresponding to a situation in which the EV owners start charging directly when arriving at home, can increase the load during hours of the day that already have high loads, thereby imposing a new stress on the electricity grid [33, 54]. However, if a controlled charging strategy is applied, such as that in response to a price signal, there is a potential to lower the impact on the grid, as well as to provide services to the electricity grid when, for example, applying V2G [33, 50, 54–62].

Zaferanlouei et al. [60] modeled the impacts of different charging strategies in a Norwegian case study of a grid that included 32 transformers [from the MV level to the LV level] and 826 electricity consumers. They used an optimal power flow model with non-linear power flow constraints and considered three different charging scenarios: direct charging; cost-minimized charging with grid constraints; and cost-minimized charging without grid constraints. They found that for the studied grid, the capacity limit when using the direct charging scenario was in the range of 18%–27% EVs. Beyond this range, thermal violations began to occur. Their cost-minimized charging scenario allowed for higher penetration levels of EVs than in the direct charging scenario, achieving up to 36% EVs before thermal violations began to occur. However, only the scenario that took grid constraints into account could handle up to 100% EVs in the studied grid. They concluded that if one wanted to achieve 100% EVs then either the distribution grids would have to be strengthened or a scheduling mechanism would have to be applied that would take the operational limits of the grid into account [60].

Veldman et al. [50] studied, using energy systems modeling, how different unidirectional EV charging strategies affect distribution grids in The Netherlands. They considered three different charging scenarios for EVs: cost-minimized charging; peak load-minimized charging; and direct charging. They allocated EVs to transformers in a set of typical distribution grids in The Netherlands, to estimate the distribution grid impacts. They concluded that cost-minimized charging could lead to high load peaks in the distribution grid and, therefore, a strong need for grid reinforcement, and that peak load-minimized charging significantly reduced the need for grid reinforcement. They postulated that the reason for the high load peaks in the cost-minimized scenario was that all the EVs were acting on the same price signal and, thereby, collectively shifting their charging to the same time and enhancing their peak demand [50]. However, their cost-minimized charging scenario used an exogenous electricity price profile and did not account for how changes to the electricity load might influence electricity prices. Furthermore, their use of typical grids means that extrapolation of the results to other regions and estimations of problems on a general level is missing. The work in this thesis investigates an entire country as the geographic region – using all of Sweden as a case study – for different EV shares of the passenger vehicle fleet and applying three different charging strategies. Furthermore, the extent to which the operational limits of the grid are exceeded is quantified, as well as when in time these events are likely to occur.

3 Models

This section includes a brief description of the types and characteristics of the models used in this work. For details of the models, see **Papers I–III**.

The statistician George Box once wrote that “All models are wrong, but some are useful” [63]. In line with this statement, a key to creating useful research is to use a model that is wrong in a correct manner. As with models, most of the results from models are wrong in one way or another, but some of them are useful. In an article published in 1976, Box further writes “Since all models are wrong the scientist must be alert to what is importantly wrong.” [64]. This is important to keep in mind when formulating research questions, choosing a methodology, and analyzing the results. The studies in this thesis were performed by developing and using two separate energy systems models. Some of the key concepts of the models are energy conservation and linear optimization. The first model used in this work is a cost-minimizing linear optimization model for hydrogen refueling stations, which was developed to compare the cost-efficiencies of different systems for providing hydrogen to refueling stations, as applied in **Paper I**. **Papers II** and **III** both apply the reference electricity grid analysis model, REGAL, which was first presented by Hartvigsson et al. [52] and is further developed in this work. The REGAL model is a simplified form of power system model for a larger geographic region. In this work, considerable changes have been made to the model to serve new purposes and increase accuracy when analyzing new research questions.

3.1 The hydrogen refueling station model

Paper I of this work compares the costs and efficiencies of three electrolysis-based hydrogen supply systems for heavy road transportation: a decentralized, off-grid system for hydrogen production from wind and solar power (Dec-Sa); a decentralized system connected to the electricity grid (Dec-Gc); and a centralized grid-connected electrolyzer with hydrogen being transported to refueling stations (Cen-Gc)(Figure 2). A cost-minimizing optimization model was developed in which the hydrogen production is designed to meet the demand at refueling stations at the lowest total cost for two timeframes: one with current electricity prices, and one with estimated future prices. The two timeframes also come with different assumptions regarding costs and efficiency levels (detailed in **Paper I**) for components such as electrolyzers and hydrogen storage tanks. The model was developed and applied to compare the system efficiency levels and costs of hydrogen delivery for the three hydrogen supply systems, and included the electricity source, energy conversion to hydrogen, and the distribution and storage of hydrogen. Optimization was carried out to satisfy an exogenous hydrogen demand profile at the lowest total cost. Although the methodology could be applied to any region, Sweden and the electricity price area SE3 were chosen as the main case and the results in this thesis are presented for this region only. In addition, three regions (Ireland, Croatia-Slovenia-Hungary, and western Spain) were modeled to determine how system costs are influenced by different electricity system compositions, as well as by different potentials for wind and solar power. The results for these additional regions are presented in **Paper I**.

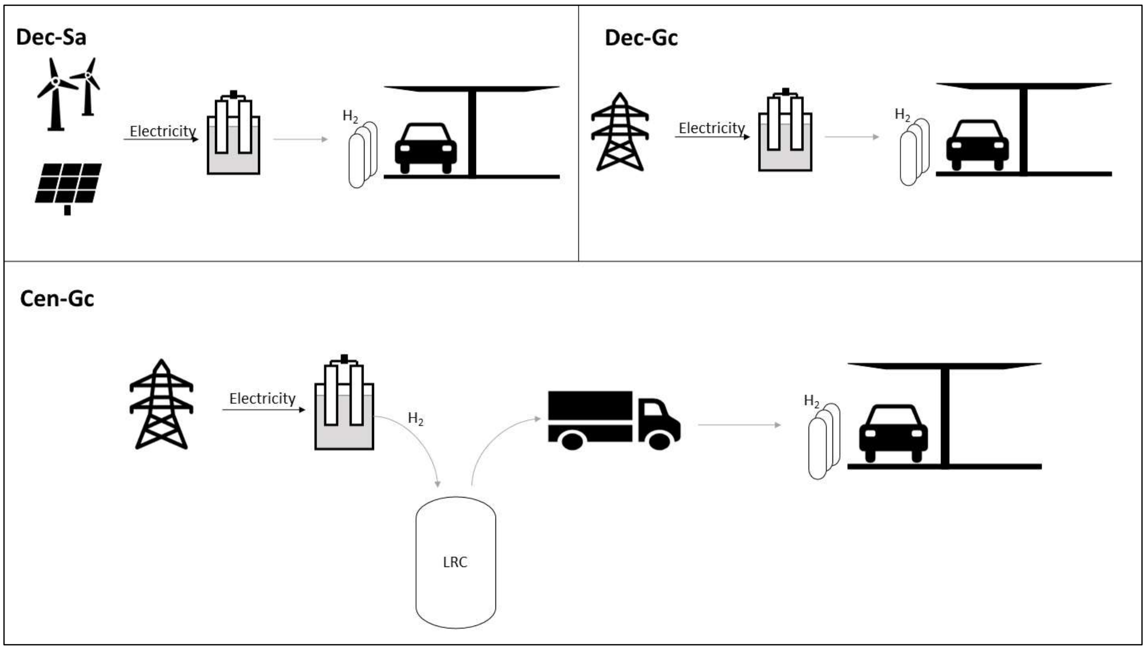

Figure 2. *Visualization of the hydrogen supply systems investigated in this work. For the Dec-Sa and Dec-Gc systems, hydrogen production occurs onsite, while the Cen-Gc system requires the transportation of hydrogen. LRC; Lined rock cavern (storage).*

Compared to other studies of hydrogen refueling systems, the present study considers multiple system setups with the same assumptions, whereas most of the previous studies were limited to one supply system (e.g., [18, 20]). Furthermore, the few studies that included multiple supply systems considered only one electricity price profile (as in [19, 25]). As the electricity price was concluded to be a substantial part of the hydrogen production cost [28], this work considers multiple electricity price profiles and investigates if and how they alter the results for the system setup and operation.

3.2 The REGAL model

Paper II presents a description of the REGAL model. However, a brief description is included in this section as an important part of the work of this thesis was the development of the REGAL model. Furthermore, the modeling with the REGAL model is more complex than the modeling for the hydrogen refueling station, so a more-detailed explanation of the methodology is needed to place the results in context. The REGAL model uses open data to create a synthetic LV grid representation (see Figure 1), which enables grid simulations of areas for which the grid properties are unknown. This synthetic grid can then be used to simulate how new technologies, in this case, large-scale home-charging of EVs, affect the LV grid and whether the operational limits of the grids would be exceeded. The REGAL model was developed for Sweden, whereby the country was divided into squares of 1×1 km^2, herein termed *grid cells*. Only residential loads are considered in the model, so unpopulated grid cells are excluded, resulting in 104,853 populated grid cells for Sweden.

In **Paper III**, a separate linear optimization energy systems model (named Multinode) is run to generate EV charging profiles that are subsequently used as inputs to the REGAL model. Figure 3 shows an overview of the main modeling blocks of the REGAL model and the interactions between the two models. In Figure 3, modeling blocks are shaded blue, and input data are shaded orange. Thus, the EV charging profiles are shaded orange because they are an input to the REGAL model, although they are an output of the Multinode model. Not all of the input data for Multinode are shown in Figure 3. The dashed line connecting the driving patterns to the EV charging profiles indicates that not all charging strategies (described later) are created using the Multinode model. More information about the Multinode model is presented in **Paper III** (see also Göransson et al. [65]).

The REGAL model consists of three main modeling blocks (described in detail in **Paper II**) that: (1) generate a synthetic LV grid; (2) perform grid simulation when adding EV charging to the residential load; and (3) evaluate power system violations. In the REGAL model, a power system violation is when the operational limits of the grid are exceeded. The violations are classified as either *voltage*, where a violation occurs if the voltage magnitude fluctuates more than what is allowed according to national regulations, or *thermal*, where a violation occurs when the thermal capacity of a component is exceeded. The REGAL model considers thermal violations in both transformers and cables.

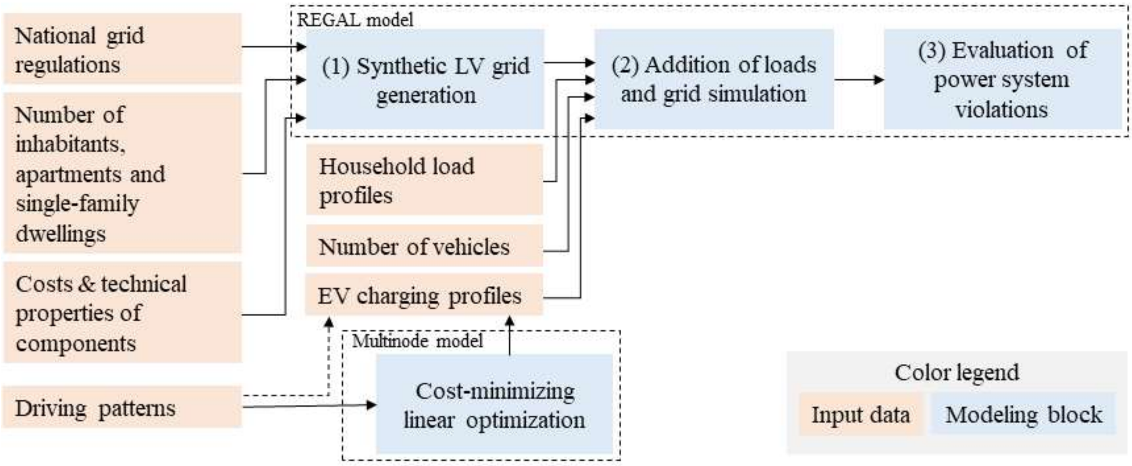

Figure 3. *Overview of the modeling blocks in the REGAL model and the interactions with the Multinode model. The Multinode model is used to generate the EV charging profiles, which can then be used to run the REGAL model. Thus, the EV charging profiles represent both input and output data.*

A reference dataset of real grid capacities was collated within the work of this thesis. The reference dataset consists of real-world data supplied by several Swedish grid operators, representing both large and small operators. This dataset was used to calibrate model parameters and validate the geographic scope for which the model is suitable for analysis. The dataset covers 9,477 out of the 104,853 grid cells applied in this work. The data per grid cell consist of: (i) the annual electricity demands for residential and commercial customers; (ii) the number of transformers with different capacities; and (iii) the cable lengths. Compared to other studies of how EVs affect distribution grids, the research presented in this work captures a larger geographic area, which is enabled by the generation of a synthetic LV grid.

Three EV charging strategies (Table 1) are applied to create charging profiles, i.e., to describe when charging occurs for the different EVs, which are then introduced one at a time to the REGAL model. The charging strategies are all created based on the driving patterns derived from a dataset of the GPS logs of 426 privately driven passenger vehicles with ICEs [66]. In this study, it is assumed that the EVs will have the same driving pattern as conventional ICE vehicles. The use of ICE vehicle driving patterns is a necessary approximation, due to the lack of driving data for EVs. The vehicles were randomly selected from the Swedish vehicle registry. The sample is representative of passenger vehicles in Sweden in terms of fleet composition, vehicle ownership, household size, household income, and the distributions of passenger vehicles in larger and smaller towns and rural areas [66].

The direct charging strategy assumes that charging occurs directly upon arrival at the home location, while the cost-minimized charging strategy tries to minimize the charging costs (in terms of the electricity spot price) while retaining the state of charge for upcoming trips. The third strategy is a mix of the first two strategies in which 30% of the vehicles charge according to the cost-minimized charging strategy and the remaining EVs apply direct charging. For the cost-minimized charging strategy, as well as for the cost-minimizing vehicles in the mixed charging strategy, the charging of the 426 vehicles is optimized in each region according to when it is most cost-efficient to charge them from the electricity system point-of-view (including both investment and running costs), thereby creating the EV charging profiles. The following constraints are imposed: (i) the vehicles cannot be charged when driving; (ii) charging at the home destination is prioritized and charging outside the home destination is performed only if the battery size is insufficient to cover the trip; (iii) all trips need to be fulfilled, i.e., driving is prioritized; and (vi) the maximum charging power is set at 6.9 kW.

Table 1. *The three charging strategies for electric vehicles investigated in this work.*

Charging strategy	Description
Direct charging	A charging strategy in which charging is done directly when arriving at the home destination until the battery is fully charged, using the maximum charging power (6.9 kW).
Cost-minimized charging*	The cost of charging in terms of the electricity spot price is minimized for all cars, i.e., considering the distribution of the EVs across the electricity price areas (SE1−SE4), with the condition that the vehicles always have the state of charge required for upcoming trips. No limitations of the LV grid are considered when vehicles decide when to charge.
Mixed charging*	In this mix, 70% of the fleet applies direct charging, while 30% of the fleet charges according to the cost-minimized charging strategy.

**The EV charging profiles in this charging strategy are obtained from modeling the northern European electricity system with the goal of minimizing the investment and running costs for the power system.*

The mathematical formulations and methodological choices in the REGAL model are described in detail in **Paper II**, and the development of EV charging profiles with different charging strategies is described in **Paper III** (and is, therefore, excluded from this thesis).

3.3 Comparison of the two models

The two models, one for indirect electrification and one for direct electrification of road transportation, are inherently different in terms of how they function and which systems they deal with. Table 2 provides a comparison of the key features of the two models developed.

Table 2. *Overview of the key features of the models included in this thesis.*

	Hydrogen refueling station model	**The REGAL model**
Paper(s)	**I**	**II** and **III**
Syntax	GAMS	Julia
Type of model	Linear optimization	Grid simulation
Temporal scope and resolution	Run over 1 year with 1-h timesteps, present-day and future case	Run over 1 year with 10-min timesteps, representation of current grid but different fleet shares of EVs
Geographic scope and resolution	Representing a hydrogen refueling station with conditions for Sweden, western Spain, Ireland or Croatia-Slovenia-Hungary	All of Sweden, divided into squares of 1×1 km^2
Main inputs	Costs and technical properties of components, hourly electricity price, hourly demand, hourly electricity generation from solar PV and wind turbines	Distributed data for the numbers of inhabitants, apartments, and single-family dwellings, number of vehicles, costs and technical properties of components, national grid regulations, driving patterns, household load profiles, and fleet share of EVs.
Main outputs	Investments in components, total system cost, hourly hydrogen production, levels in hydrogen storage	Synthetic representation of the LV grid, frequency (i.e., how often) and amplitude (i.e., by how much) of exceedance of the operational limits of the LV grid, and when exceedances occur, what types of operational limits are exceeded.

4 Results and discussion

This section presents and discusses some of the main results from the work included in this thesis. Additional results are presented in the individual appended papers.

4.1 Cost-efficient hydrogen supply systems for heavy transport

Figure 4 shows the levelized cost of hydrogen (LCOH) for the different hydrogen supply systems for the two studied timeframes, assuming the current and future costs for both investments and electricity. The electricity costs shown in Figure 4 include the costs for electricity used for hydrogen production and compression. The results show that the lowest costs for delivering hydrogen in southern Sweden, in the range of 2.2–3.3 €/kgH_2, are achieved with the decentralized, grid-connected system (Dec-Gc). For the centralized hydrogen supply system, Cen-Gc, somewhat lower costs are achieved for the production and storage of hydrogen, although the additional cost for hydrogen transportation brings the total cost to 3.7–4.8 €/kgH_2, which is 31% higher for the current case and 41% higher for the future case, as compared with the Dec-Gc system. The Dec-Sa system, which is disconnected from the electric grid, is associated with the highest LCOH, mainly due to the higher costs for storage and electricity production, as shown in Figure 4. For all the tested systems, lower costs are achieved in future cases than in the case corresponding to the present conditions, as seen in Figure 4. This is due to the assumed reduction of investment costs and the higher energy efficiency of electrolyzers. For the grid-connected systems, these are also the main contributors to the lower cost for this system, although electricity price variations also affect during which hours hydrogen is produced and, thereby, the electricity costs.

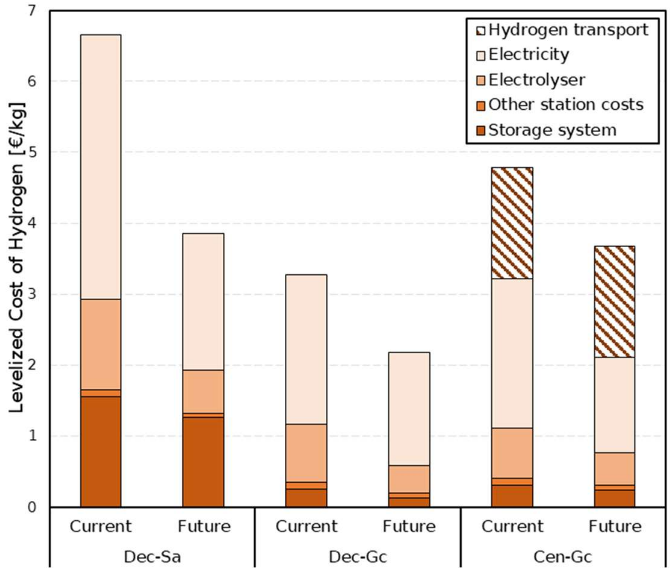

Figure 4. *Levelized costs of hydrogen delivery for the three hydrogen supply systems (Dec-Sa, Dec-GC, Cen-GC) and the two timeframes (Current and Future) investigated. Source:* ***Paper I****.*

Figure 5 shows the hydrogen production costs for different electricity price profiles when using the hydrogen refueling station optimization model for the decentralized, grid-connected supply system (Dec-Gc). The results in **Paper I** include the individual years in the period of 2015–2020, and a future case, which means that the results for 2021–2023 are new and are not included in **Paper I**. There are differences in the LCOH values between the modeled years, supporting the notion that electricity prices influence the LCOH. For the years included in **Paper I**, similar capacities were seen for electrolyzers and storage units, meaning that they only differed in terms of electricity costs. However, for the newly introduced years, some differences in investments in hydrogen storage and electrolyzer capacity are seen. The main anomaly is apparent for Year 2022, when electricity prices were higher in general, but were also more-variable than in the preceding years. This led to Year 2022 having larger investments in both electrolyzer capacity and hydrogen storage, to enable the shifting of hydrogen production to hours with lower electricity prices. As the other years do not have such high electricity prices, the increased investments in storage capacity as compared to other years might not be reasonable. To identify the optimal solution if more than 1 year is considered, a cost-optimal solution for the period of 2019–2023 was modeled, which is included in Figure 5. The result of the co-optimized solution for multiple years shows that it is not feasible to invest in larger storage capacities based on a high electricity price in a single year. However, since future electricity prices reflect both national policies and geopolitical developments, as was the case for Year 2022, this introduces uncertainty as to which electrolyzer and storage capacities remain cost-optimal over time. However, it should be noted that even for the case with the largest storage capacity, the storage covers the demand for only approximately 2 days and 7 hours, which means that only the high electricity price periods are avoided, rather than production being shifted by several weeks or months. From a security of supply perspective, the storage capacities derived in the cost-optimal solution are rather small compared to the demand. To ensure continuous operation during hours without electricity supply, larger storage units are needed. However, the value of self-sufficiency is not considered in the optimization model. Furthermore, it does not include any buffer in the storage capacity that would allow trucks to refuel at different times than those laid out in the assumed pattern. For this reason, the cost figures presented in this thesis should be seen as the lowest possible average LCOH under the given assumptions related to costs and efficiencies.

The different cost-optimal solutions for different years illustrate the difficulty associated with estimating which system will be cost-optimal in the near future based on historical data. Considering the results presented in **Paper I** and comparing them to the additional years included in the updated version of Figure 5, different results are achieved due to the different patterns in electricity prices in the past years. At the time that **Paper I** was written, the electricity prices up until Year 2021 were available, and the last two years (2020 and 2021) were seen as being unrepresentative due to the COVID-19 pandemic, which was the rationale for using Year 2019 as the basis for the studies of current costs in **Paper I**. Little did we know that the coming years would create a new geopolitical energy landscape with Russia’s invasion of Ukraine in 2022, which heavily influenced the electricity prices in that year. Although the electricity prices differ between the years, the Dec-Gc system still has the lowest LCOH for all the studied years.

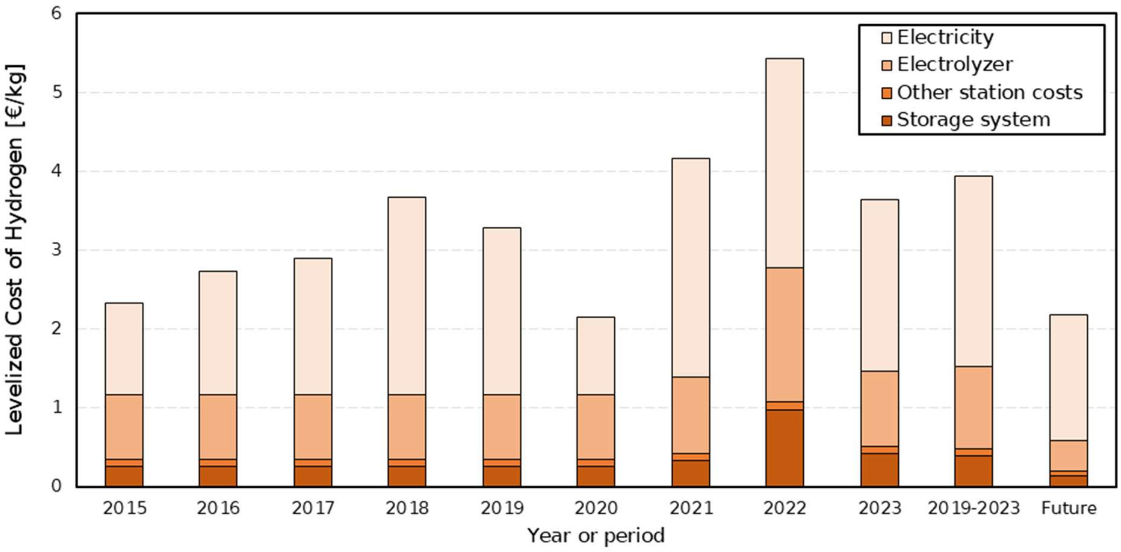

Figure 5. *Hydrogen production costs using different electricity price profiles for the decentralized grid-connected hydrogen supply systems. All results are for the year stated on the x-axis, with the exception of 2029–2023, which is a co-optimization for the 5 years listed. The results are from Paper I (period of 2015–2020 and the future estimation) and new results derived for this thesis (period of 2021–2023 and the co-optimized results for 2019–2023).*

As there are uncertainties regarding the cost of the hydrogen supply, the results in **Paper I,** as well as the new results presented here, should be regarded as estimates of the differences between different types of hydrogen supply systems, rather than as estimates of the hydrogen supply costs in absolute terms. In addition, the estimates for the future case should not be seen as predictions, but instead as a comparison between today's electricity system and future systems with more-volatile electricity prices.

The results obtained from the modeling of hydrogen refueling stations with different hydrogen supply systems show that different systems are associated with different costs. The results presented in this work represent optimized solutions with perfect foresight. Therefore, it is likely that real-world refueling stations would need larger storage systems than those presented in this study, as there must be some element of flexibility to a cost-optimal solution. In addition, the hydrogen will be sold at a price that ensures a profit margin. The real price of hydrogen delivery will, to a significant extent, depend on the extent of utilization of the hydrogen refueling station. This means that the market penetration level will affect the profitability of introducing hydrogen refueling stations. Thus, real-world conditions will increase the costs of the hydrogen supply systems, and these increases may differ across the different hydrogen supply systems.

The hydrogen refueling station model is a simple model that has several limitations. As an example, the model optimization in this work is designed to minimize the total system cost, which does not necessarily provide the optimal system configuration, as there may be important design factors other than costs. For example, an advantage of the Dec-Sa system that is not valued in the model is its self-sufficiency and lack of sensitivity to technical changes in the other parts of the electricity system. Another potential advantage of such a system is the possibility to establish refueling stations in areas where the electricity grid capacity cannot accommodate a grid-connected solution, or where development of the grid is more costly than assumed in this study. A centralized system, such as the Cen-Gc system, could also be an option in areas that have limitations related to grid capacity, since for a production site in a centralized system, especially one with distribution through hydrogen pipelines, there is more freedom with regard to the placement of the hydrogen production site. This means that hydrogen refueling stations could be placed in areas with poor grid availability and still have access to clean hydrogen, as long as the refueling station is connected to the network of hydrogen pipelines.

4.2 Validation of the generated LV grid

Development of the REGAL model included in this thesis involves the validation of the model against the calibration dataset with information provided by electricity grid operators. Validation was carried out on both the grid cell level and group level. The average deviation and the average absolute error over all grid cells, when aggregating grid cells over seven regions in Sweden, are shown in Figure 6. Definitions of the 'error' and 'deviation' terms are found in **Paper II**. The regions are sorted in Figure 6 such that the number of grid cells included in the region increases with the region number. This means that regions R1 and R2 (see Table 6 in **Paper II**), which have the largest average deviations (above ±10%) also have the lowest numbers of grid cells. These regions also have the highest population densities.

Grouping the grid cells into the municipalities and regions in which their midpoints lie, the results for comparisons of the transformer capacities in the model and the real-world data are shown in Figure 7. The number on the *y*-axis shows the average deviation in transformer capacity for the grouping, so it indicates if there is a bias towards over- or under-dimensioning the transformers in the group. For most of the municipalities and regions present in the calibration dataset, the entire area of the municipality is not represented. The dashed line in Figure 7 shows the smallest area in km^2 of a municipality in Sweden, which means that for groups with fewer grid cells than this, the entire municipality is definitely not included in the calibration dataset. In Figure 7, it is clear that the average deviation in a group nears zero as the number of grid cells included in the grouping increases. This indicates that the model is more-accurate for larger geographic areas. All regions that include more than 350 grid cells have an average deviation that is lower than ±10%. Since 241 out of 290 municipalities have an area of 350 km^2 or more, most municipalities are represented sufficiently well for the studies to be performed if the calibration dataset is representative.

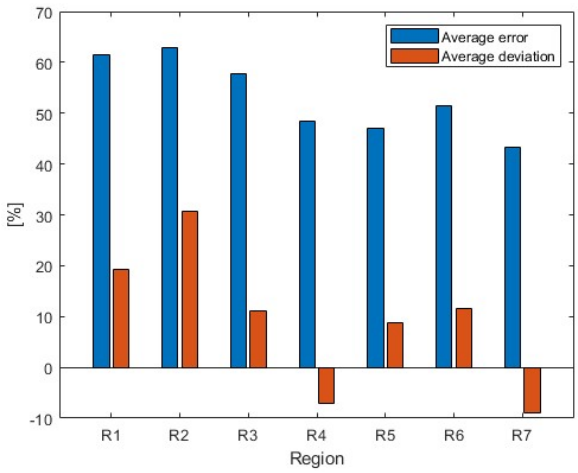

Figure 6. *Error values (blue) and deviation values (red) of the transformer capacity averaged over all grid cells in the geographic grouping R1 to R7 (see Table 6 in* ***Paper II****). Definitions of 'error' and 'deviation' are provided in* ***Paper II****. Region names have been anonymized to prevent the identification of sensitive data received from grid operators. Source:* ***Paper II****.*

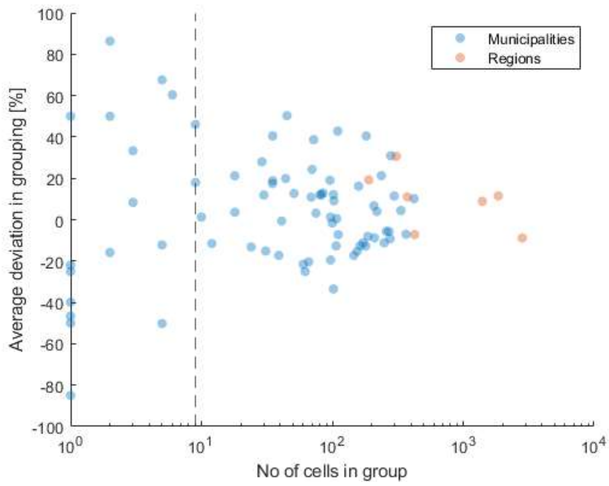

Figure 7. *Deviation values of the transformer capacity averaged over the grid cells in the municipalities (blue) and regions (orange) (y-axis) and the number of grid cells in the municipality or region (x-axis). The x-axis is logarithmic with a base of 10. A vertical dashed line is shown for nine grid cells, as the smallest municipality in Sweden has an area of approximately 9 km^2. Source:* ***Paper II****.*

The use of a synthetic grid representation allows for estimations of the hosting capacities in those cases where detailed information on the state of the grid is not publicly available. However, where possible, more-accurate results will naturally be achieved with real grid capacities. This means that a model such as REGAL can provide initial indications as to where and when problems will occur in the grid when adding, for example, EV charging (as is done in this work), although the model will seldom make predictions that are accurate for a small geographic area (such as 1 km^2). As can be seen in the validation exercise, the model can make accurate predictions of transformer capacities when assessing the average deviation from real-world data for a larger area, such as a region. For a given population density, some grid cells will have a larger transformer capacity in the REGAL model than is evident from the data provided by the grid operators, and some grid cells will have a smaller capacity. When the transformer capacity in the model is smaller than in reality the average number of timesteps with violations will be overestimated, whereas, in a grid cell with a larger transformer capacity, the average number of timesteps with violations will be underestimated. As the dimensioning of transformers has been calibrated to have a close-to-zero deviation, while ensuring that the errors are as small as possible on the grid cell level, this issue will to some degree cancel itself out, yielding correct average estimates for larger groups of grid cells.

Compared to previous studies (e.g., Schachler et al. [54] and Zhu et al. [47]), the work presented in this thesis is a clear improvement based on the extensive results obtained for the model validation, which increases the transparency levels of the strengths and weaknesses of the model and, thereby, the transparency related to which types of questions it can answer. In relation to studies of smaller areas with real grid capacities, the synthetic grid representation of a large geographic region increases the likelihood that the general conclusions will be correct but reduces the accuracy levels for specific areas. Therefore, the work included in this thesis is useful for drawing general conclusions about, for example, differences between charging strategies, and making an analysis from a societal perspective rather than answering specific questions about future loads in a grid cell.

4.3 The impacts of different charging strategies on the LV grid at different EV fleet shares

Figures 8 and 9 show how the power system violations increase as the share of the passenger vehicles that are electrified increases for the three different charging strategies (with each symbol corresponding to one model run). Figure 8 shows the share of grid cells for which, statistically, there is on average one or more violation in a year. The figure shows a non-linear increase with EV fleet share. Figure 9 shows the average number of timesteps with a violation per grid cell, whereby the violations are averaged across all grid cells and iterations, with different randomized additions of household and EV load profiles. Figure 8 and 9 show thermal and voltage violations together. As can be seen in both figures, there is a strong increase in the number of power system violations when there is an increase in the share of EVs in the passenger vehicle fleet, regardless of the charging strategy applied. As expected, the direct charging strategy has the highest average number of violations, as well as the largest share of grid cells with violations among the three charging strategies. For the average number of timesteps with violations (Figure 9), the increase in violations with EV share initially progresses slowly, and becomes more rapid as the fleet share increases. The behavior evident in Figure 8, with the increase in the share of grid cells with violations being non-linear, is related to the different levels of excess capacity in the transformers. While the increase in the share of grid cells with violations is small in Figure 8, although the number of violations increases in Figure 9, the increase in number of violations occurs in grid cells that already have violations. This is seen between fleet shares of 50% and 100% in the direct charging strategy and between fleet shares of 75% and 100% in the cost-minimized charging strategy, where the number of violations increases in Figure 9, while the increase in the share of grid cells with violations is much smaller in Figure 8. In some grid cells, no power system violations occur even with large EV fleet shares.

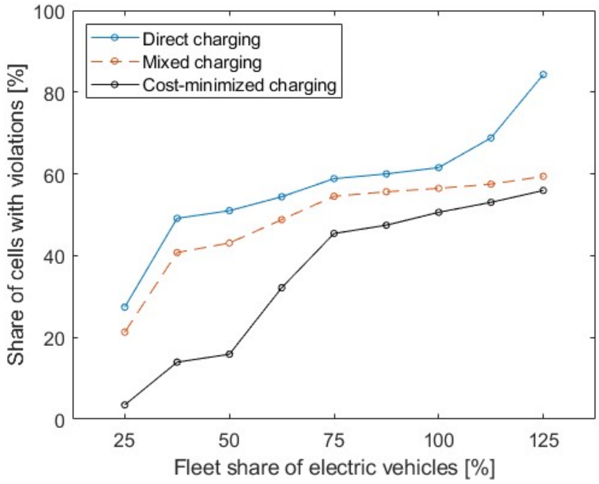

Figure 8. *The shares of grid cells with power system violations for the three charging strategies for the different shares of EVs investigated in this work. Both thermal and voltage violations are considered. Source:* ***Paper III****.*

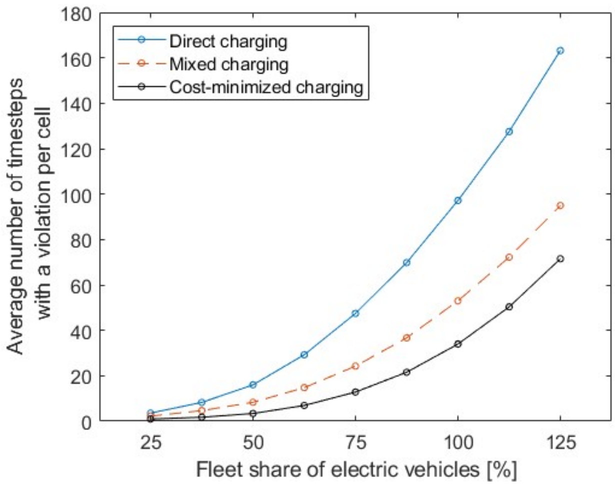

Figure 9. *The number of timesteps with a power system violation per grid cell averaged over the number of iterations for the three charging strategies and the different fleet shares of EVs. Both thermal and voltage violations are considered. Source:* ***Paper III****.*

The violations that occur as the EV fleet share increases are not evenly distributed across the modeled grid cells. Even with a high level of EV penetration, some grid cells have no power system violations, while in other grid cells violations occur already at a low EV fleet share. As an example, Figure 10 shows the share of grid cells that manifest a number of timesteps with thermal violations in the transformer above a certain value when adding EV charging, averaged across all the iterations. The number on the *x*-axis corresponds to the number of timesteps during a year in which a thermal violation in the transformer occurs, averaged over all the iterations. As can be seen, most of the thermal violations in the transformers occur in the groups with a high population density (i.e., city and urban grid cells), for all three charging strategies. The value obtained for all the grid cells together is similar to that for the group of rural grid cells, as the number of grid cells in the rural group is much higher than in the other groups. For the direct charging strategy (Figure 10a), the majority of the city and urban grid cells have a number of timesteps with >100 violations/year (corresponding to a total of 16 hours and 40 minutes), and more than one-third of the urban grid cells and a majority of the city grid cells have a number of timesteps with >100 violations/year (corresponding to a total of 6 days, 22 hours and 40 minutes). For the cost-minimized charging strategy (Figure 10b), a lower number of timesteps with thermal violations is achieved, as compared to the direct charging strategy. The mixed charging strategy has shares of grid cells with violations that are intermediate to the values seen for the other two charging strategies.

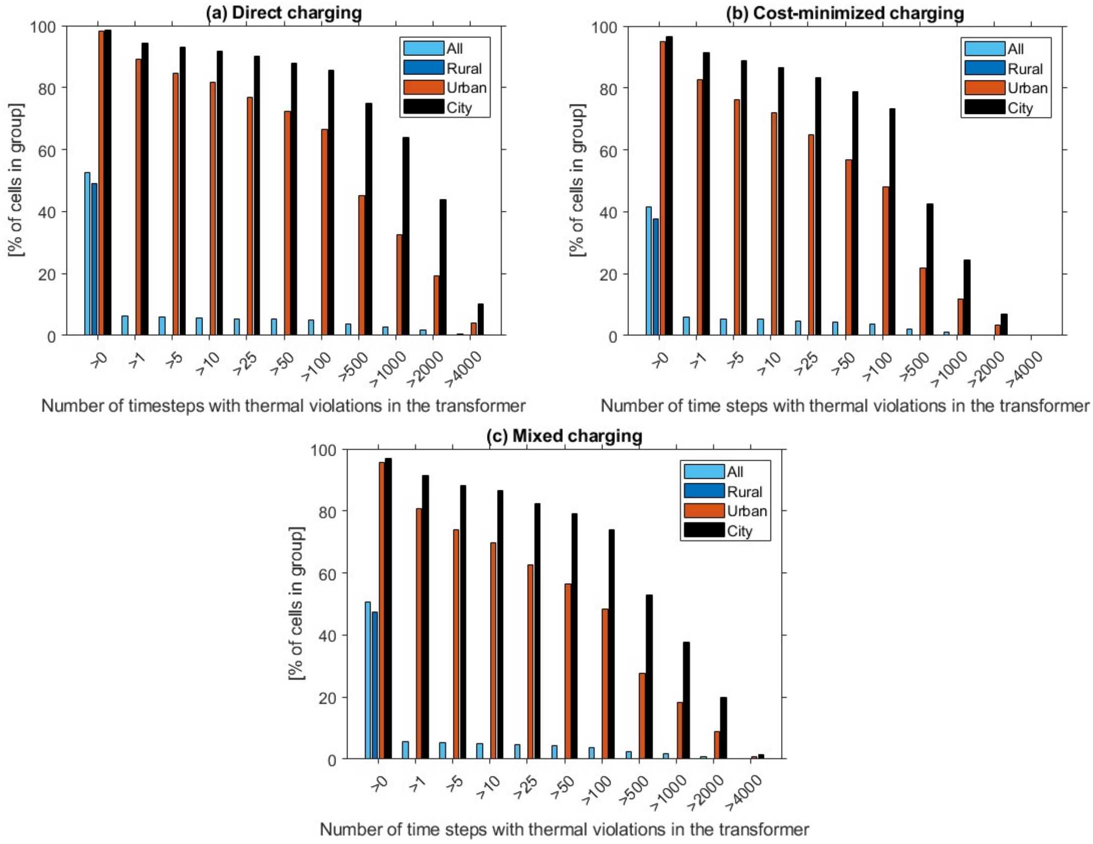

*Figure 10. Shares of grid cells with thermal violations in the transformer above a certain value when adding EV charging (with 100% of the current vehicle fleet electrified) for the (a) Direct charging, (b) Cost-minimized charging, and (c) Mixed charging strategies. The results are shown for rural, urban, and city areas, as well as for all grid cells. The results shown are the average values across all iterations. Source: **Paper III**.*

The results obtained from the model show that the number of power system violations within a grid cell when adding EV charging to the synthetic representation of LV grids varies substantially across different grid cells. As expected, there is a steep increase in the number of violations with increasing EV fleet share. However, even with a high level of EV penetration, some grid cells experience no power system violations, while in other grid cells violations occur already at a low EV fleet share. The non-linear shape of the increase in both fleet share and number of violations is not as expected. The shape of Figure 8 shows an early increase in the share of grid cells with violations, which later flattens out only to increase again. Furthermore, we know from the validation and model formulation in **Paper II** that there is a lower percentual margin of transformer capacity in urban and city grid cells. Moreover, we know from Figure 10 that transformer violations are much more common in urban and grid cells. This could be an indication that the city and urban grid cells are beginning to achieve violations at low EV fleet shares. However, since the urban and city cells account for a very small share of the total number of grid cells, this is not the full picture.

To investigate what happens at low EV fleet shares, some additional results (not included in the appended papers) for lower EV fleet shares are shown for the direct charging strategy. In similarity to Figure 10, Figure 11 shows the share of grid cells that manifest a number of timesteps with thermal violations in the transformer above a certain value when adding EV charging, averaged across all the iterations, but with different EV fleet shares (25%, 50%, 75% or 100%). It shows that thermal violations appear in a substantial number of the urban and city grid cells with an EV fleet share as low as 25%, albeit for fewer timesteps than with higher fleet shares. Figure 12 shows the shares of grid cells that achieve different numbers of voltage violations with EV fleet shares of 25%, 50%, 75%, and 100 %. Considering Figure 11 and Figure 12 together, it can be concluded that violations appear early in all types of grid cells. For thermal violations, they occur mainly in urban and city grid cells, while rural grid cells are more affected by voltage violations. However, for both types of violations, the number of timesteps in which issues occur is much lower with a smaller fleet share of EVs. Regarding the results for all grid cells together in Figure 11 and Figure 12, it is clear that most of the grid cells with violations for small fleet shares in Figure 8 stem from voltage violations in rural grid cells, although the grid cells in which thermal violations occur have a higher number of timesteps in which these violations occur. This means that despite the share of grid cells in which violations occur being mostly affected by voltage violations, the average number of timesteps with violations (shown as a function of EV fleet share in Figure 9) is also affected by the thermal violations, as the grid cells with thermal violations have a higher number of timesteps in which they appear.

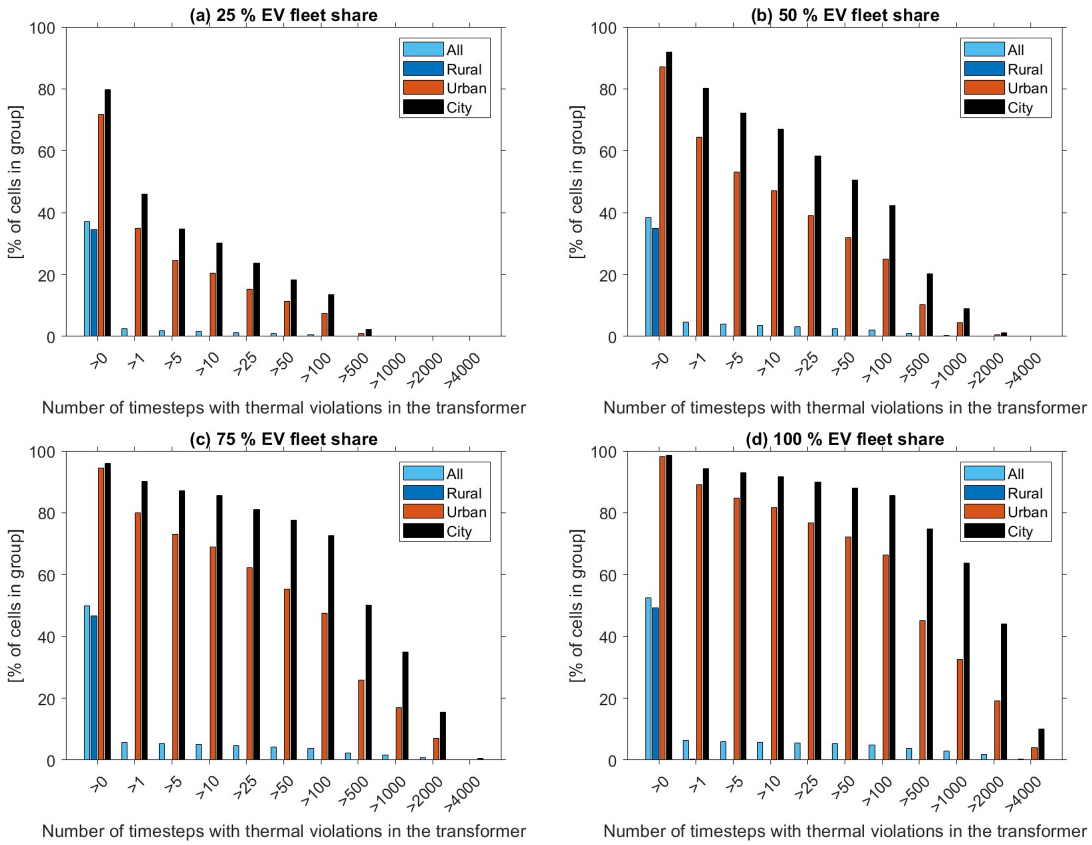

Figure 11. Shares of grid cells with thermal violations in the transformer above a certain value when adding EV charging at four different EV fleet shares: (a) 25%, (b) 50%, (c) 75%, or (c) 100% of the current vehicle fleet electrified for the Direct charging strategy. (a), (b) and (c) are new results, not included in previous papers. The results are shown for rural, urban, and city areas, as well as for all grid cells. The results shown are the average values across all iterations. Results for the 25%, 50%, and 75% EV fleet shares are new results generated for this introductory essay, while the results for 100% EV fleet share are from ***Paper III****.*

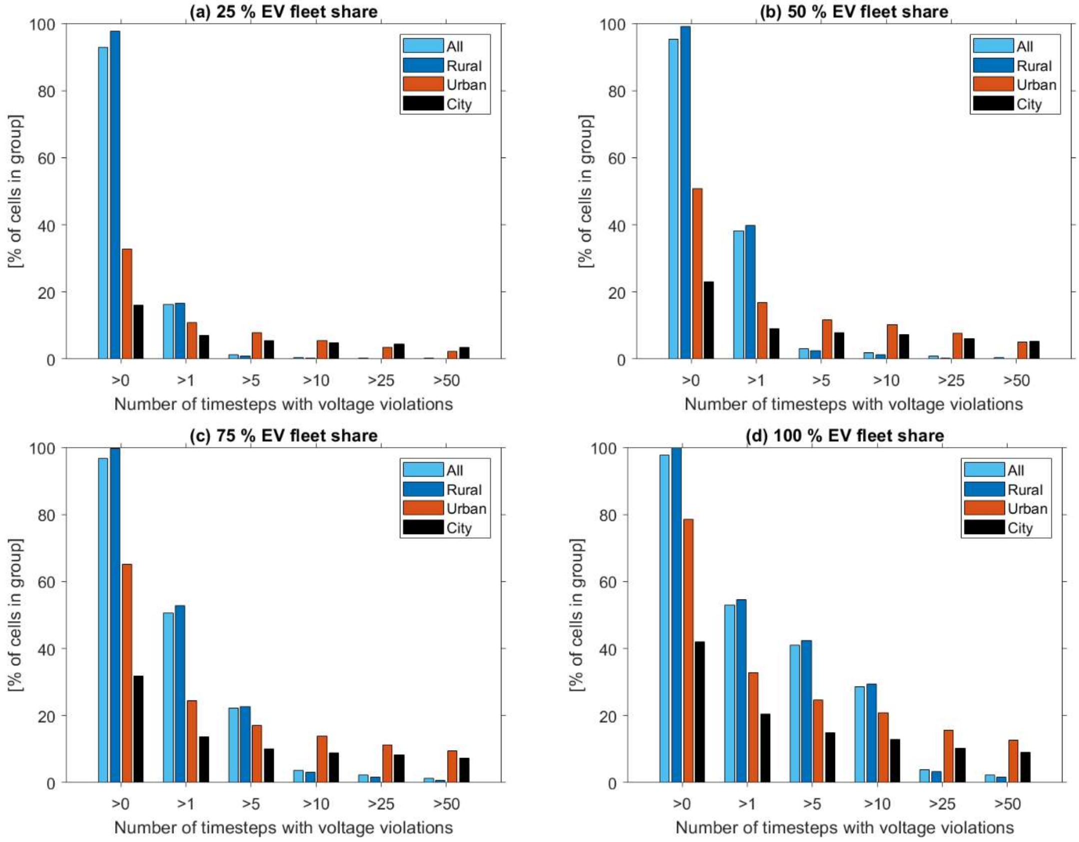

Figure 12. *Shares of grid cells with voltage violations in the transformer above a certain value when adding EV charging at four different EV fleet shares: (a) 25%, (b) 50%, (c) 75%, and (c) 100% of the current vehicle fleet electrified for the Direct charging strategy. Panels (a), (b) and (c) represent new results that are not included in the appended papers. The results are shown for rural, urban, and city areas, as well as for all grid cells. The results shown are the average values across all iterations. The results for the 25%, 50%, and 75% EV fleet shares are new results derived for this introductory essay, while the results for 100% EV fleet share are presented in* ***Paper III****.*

4.4 Limitations of the REGAL model

The REGAL model only considers residential loads, which is a weakness of the model. Nonetheless, this was deemed sufficient to answer the studied question, as home charging is by definition introduced in homes. However, dimensioning the grid exclusively for residential loads means that the model does not take into account the spare transformer capacity linked to commercial or industrial needs. Typically, larger industrial applications will be connected at a higher voltage level, so they are not relevant to consider for an LV grid, even though commercial loads are present in many LV grids. Excluding these industrial loads may overestimate or underestimate the grid capacity, depending on the coincidence of EV charging and the loads not included in the model.

The modeling in this work considers household loads and EV loads separately. As the charging profiles do not consider the size of the fuse installed in a home, they do not take into consideration that a smart home charger can monitor the overall load in the home and alter the charging power to reduce the total home peak load. As houses typically have a fixed fuse size and there are EV chargers that can take this into account, the present work may have overestimated the maximum power levels of individual households when adding the EV load. Thus, integrating the household and EV loads into the modeling would improve the accuracy of the results, albeit at the expense of dramatically increased computational time.

EVs are assumed to be used at the locations where passenger vehicles are currently registered as operating in traffic. This might not be an accurate assumption, as there might be households today that possess more passenger vehicles than are used regularly, meaning that not all passenger vehicles in the household would need to be charged at the same frequency as a vehicle that is used by a household with fewer vehicles per driver. Furthermore, vehicles may be charged in residential buildings at which the owner of the vehicle is not registered to live, such as a vacation home. It is also possible that in the future a large proportion of the population in some areas will choose not to own or use a vehicle to the same extent as today (for example, in cities with increasing populations).

The EVs in this modeling study all have the same battery size, same electricity consumption per kilometer-driven, and the same maximum power of their home charger. However, in reality, this is not the case, as there exists a multitude of capacities for these features. These assumptions could affect the results in several ways. For example, having a larger battery size can increase flexibility with regards to when charging occurs, while a higher maximum power of charging may increase the load peaks from EV charging. Furthermore, the charging patterns are based on ICE vehicles, for which the driving patterns and other behavioral factors could differ. Therefore, one way to improve this study would be to use the vehicle logs of actual EVs, which could be selected to be representative with regards to vehicle properties, but also with regards to the socioeconomic characteristics of the vehicle owner. Using a linear optimization model to generate the EV load profiles for the cost-minimized charging strategy raises additional issues. First, the model assumes perfect foresight for all decisions, meaning that all the marginal electricity prices for the entire model scope are already known when deciding when the EVs are charged. In contrast, real-life EV owners might know only the day-ahead electricity spot price. This limited foresight might cause EV owners to prioritize charging earlier than in the model, as future prices are unknown. Second, the model will shift charging times based on any difference in electricity price, meaning that price differences that are too small to influence real behavior might have significant consequences in the model. Third, the charging profiles are generated using a model that has different geographic and temporal resolutions than the model applied in this study. The temporal resolution when generating the charging profiles has an hourly resolution and the geographic resolution is electricity price areas. When implementing the profiles in the REGAL model, it is assumed that charging is performed at a constant rate for all 10-minute timesteps within an hour. This might not be the case, which means that the charging profiles generated in this work might be smoother than real-life charging profiles, thereby decreasing the possible peaks in electricity demand for charging. This could underestimate the number of violations occurring in the distribution grid.

Further results in relation to the amplitude of exceedances of grid capacity and when in time they occur are described in **Paper III**. The work presented in **Paper III** explores in greater details the frequency and amplitude of the exceedances of grid capacity (compared to, for example, Zaferanlouei et al. [60] and Veldman et al. [50]). Thus, information other than that exceedances happen at certain levels of EVs in the vehicle fleet is available. This is a better starting point from which to explore the measures that could be taken to alleviate these issues.

4.5 General remarks

Electrification as a strategy to reduce environmental burden involves moving from a fuel-driven system to a material-driven system. The idea is that the trade-off between the increase in material use and the decrease in fuel use reduces pressures on ecological systems. However, there are many driving forces and multiple usage patterns, as well as several assumptions that influence the estimations of environmental pressures, as well as their eventual impacts. While these are not evaluated in this work, their existence and the need for further analysis are important to bear in mind and appreciate before drawing conclusions as to which system *should* be developed or which technologies are most-suitable overall.

Furthermore, a large share of the transport demand has a small or no value in its own right. Rather, the transportation demand arises from services to supply other needs, such as to connect a person with a demand for work (creating a commuting behavior to and from work). In that example, the demand is related to enabling the person to work, not for them to drive a car between their home and work locations. This demand could be fulfilled in numerous ways, where from an energy point of view, the most-effective strategy might be to work from home if possible or otherwise to travel collectively. This relationship between the needed service and traffic volume has not been explored in this thesis, although it should be noted that switching to more-efficient forms of travel is beneficial from both the electricity and resource points of view, as compared with maintaining a large passenger vehicle fleet and high goods volumes if the desired services can be achieved without them.

5 Main findings

Three hydrogen supply systems were evaluated using a cost optimization model in **Paper I**, to gain insights into the cost of supplying hydrogen to the transport sector. The costs of hydrogen delivery are in the range of 2.2–6.7 €/kgH_2 in Sweden. The lowest cost for hydrogen delivery is achieved with the decentralized grid-connected supply system (Dec-Gc). From the comparison of decentralized and centralized grid-connected hydrogen supply systems (Cen-Gc and Dec-Gc), it can be concluded that, given the assumptions presented in **Paper I**, a centralized production system (Cen-Gc) is approximately 30%–40% more expensive than a decentralized grid-connected system (Dec-Gc) in Sweden. Although slightly lower costs for hydrogen production and storage are achieved in the Cen-Gc system, the additional cost for hydrogen transport to the refueling station results in a higher total cost. Thus, the higher cost for hydrogen transport offsets the advantage of having access to large-scale hydrogen storage. If there is an existing system for hydrogen transport (such as an existing system of hydrogen pipelines) that is used for other purposes, it might be more cost-effective to use that system. For the centralized system (Cen-Gc), an increase in electricity price variations between hours strengthens the business case for investments in larger and cheaper hydrogen storage solutions, which can enable shifts in hydrogen production to periods with low electricity prices. For future cases, the hydrogen production costs are 23%–42% lower than when assuming today's prices for the different hydrogen supply systems, for Swedish conditions. This is due to a combination of assumptions related to decreased investment costs (e.g., investment costs for electrolyzers) and lower costs for purchased electricity.

In **Paper II**, the REGAL model is presented and validated against a large dataset of real-world transformer capacities and electricity demands. Thus, open data describing the population and distribution of dwellings in Sweden can be used to estimate the electricity grid capacities for the LV grid. Different calibration values are explored and the levels of accuracy of estimations of grid capacities are calibrated using proprietary real-world data from distribution system operators (DSOs). Thus, for a region that includes many grid cells, an average deviation from the real-world data of ±10% is achieved. For an average grid cell, an error of 44.5% is seen, which means that the model is not suitable for analyses of an area of 1 km^2. However, the level of accuracy is deemed sufficient for initial estimations of hosting capacity for larger geographic areas, such as a region or a country.

The work in **Paper III** of this thesis shows that there is an increase in the number of power system violations in an LV grid that has an increased share of EVs in the vehicle fleet. Initially, the increase in the number of violations with increased fleet share proceeds slowly, though the larger the share of EVs in the vehicle fleet, the greater the increase in the number of violations for each additional vehicle. The number of timesteps with violations varies significantly across different geographic regions in Sweden. Even with a high level of EV penetration, some grid cells have no violations, while in other grid cells violations are recorded already at small EV fleet shares. Most violations are seen in areas that have a high population density, especially for violations that involve the thermal capacity of the transformers being exceeded. The choice of charging strategy, i.e., direct, cost-minimized or mixed charging, affects both how often and to what extent the operational limits of the grid are exceeded. On average, direct charging of EVs yields the highest frequency and largest amplitude of violations. However, the highest loading of a transformer and the largest voltage drop in a grid cell are achieved with a charging strategy that minimizes the costs for charging, as these increase the coincidence of EV charging.

6 Future work

The integration of electricity and transportation systems is a broad topic, with many issues to be explored in future research studies. Some aspects of future research that have been identified during this work are presented below.

For hydrogen supply systems, the next step in this work could be to study sector coupling with industrial applications of hydrogen, to investigate the extents to which production and storage units could be shared. In addition, one could look at what supply systems for multiple refueling stations might look like and how optimization is impacted by studying different scopes, such as comparing the implementation optimization of one or several refueling stations or of a country or a continent. If adopting a larger geographic scope, it would be beneficial to consider also the locations of refueling stations in relation to each other and to road networks.

For direct electrification, the modeled charging strategies in this work have focused on unidirectional charging. However, since a car battery has the potential to work as a storage unit for electricity, and as more and more vehicles are equipped to enable V2G, it seems likely that bidirectional charging will be an option in the future. This could both improve and exacerbate the problems observed for the LV grid depending on when the charging and discharging of the vehicle battery occur. The different types of signals upon which V2G is performed are therefore interesting to study, alongside the issues that might arise for the LV grid.

Strong focus has been placed on quantifying the issues that are likely to occur in the LV grid. A natural continuation of this work would, therefore, be to explore how these issues could be alleviated. After identification of the specific measures that are technically possible for the alleviation of such issues, further work could examine the cost-efficiency and resource-efficiency of the different measures, as well as which actors have the possibility to implement these measures. In addition, other technologies, , such as stationary batteries and solar PV, are likely to be introduced into residential LV grids. It would be beneficial to include such technologies in the model, to see how interactions between the different technologies affect the issues that are likely to occur and the possible alleviation methods.

When assessing the infrastructure development that is needed to enable the electrification of transport, the resource-efficiencies and environmental burdens of different solutions warrant study. As ICE cars are progressively phased out, the environmental burden is shifted towards material use, increasing the role and importance of estimated embodied emissions, something that has not yet been addressed in this context.

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