

Impact of electric vehicles: Will German households pay less for electricity?

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ABSTRACT

High energy efficiencies imply that electric mobility is regarded as an important technological option to reduce greenhouse gas emissions from the transport sector. However, electric vehicles (EVs) also have impacts on electricity grids and electricity generation. Hence, this paper explores how private EVs affect residential electricity prices in Germany. We examine effects of EVs on electricity generation, the contribution of controlled charging and impacts on distribution grid grids. We show that in 2030, private EVs can reduce the electricity prices for households since at distribution grid level, the additional electricity demand increases the overall utilisation of the grid and lowers specific costs. Because the additional load of EVs leads to an increased usage of power plants with higher variable costs, there is the opposite effect on electricity generation costs, although limited by controlled charging. Overall, the effect of rising electricity generation costs is usually over-compensated by falling specific grid charges.

1. Introduction

At present, significant growth rates for electric vehicles (EVs) are being recorded worldwide [1]. As a consequence, renewable electricity (RE), especially wind and photovoltaic (PV), can be used to meet mobility requirements, while simultaneously reducing greenhouse gas emissions and the dependency on import of energy carriers [2–4]. At the same time, pure battery EVs (BEVs) are now able to meet today's mobility demands since vehicles with larger batteries are sold [5].

An additional net electricity demand¹ of around 12 TWh can be calculated for 2030 given a market penetration of approx. 4 million EVs² in Germany; the country's total net electricity demand in 2016 was about 525 TWh [6]. The substitution of conventional fuels (petrol and diesel) by electrical power and the resulting increasing demand for electricity give rise to questions about the impacts of e-mobility on the electricity system as a whole. The additional demand for electricity must be met by the installed generation capacity in order to maintain the security of supply. At the same time, it can be assumed that there are also relevant local effects due to EV charging, in particular at distribution grid level.

In this study, we combine different energy system models in order to quantify the aspects mentioned and make a holistic assessment of the impacts of private EVs on the electricity system. The electricity price for households is used as an indicator of the cost effects. We thereby examine the following specific questions:

Demand-side:

- How is the load due to charging EVs distributed with hourly resolution and considering different charging powers?

Supply-side:

- What impacts do EVs have on the hourly electricity demand and therefore on electricity generation costs?
- To what extent does controlled charging lead to a reduction of the electricity generation costs?

Distribution grid:

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¹ Electricity production without self-consumption from power plant, including grid losses and charging losses (in addition to consumption while driving).

² Both BEVs and plug-in hybrid electric vehicles (PHEVs).

- What influence does charging EVs have on investments in grid expansion in distribution grids and on the resulting grid charge?

We link four models to chart the influence of EVs on the electricity price for households in Germany: The market diffusion model *ALADIN* simulates the future diffusion of EVs and their charging behaviour. Its output then enters the simulation model *eLOAD*, which projects the system load of relevant drivers for 2030. *eLOAD* can also simulate the use of controlled charging of EVs. In the next step, the total hourly electricity demand (system load) is transferred to the electricity market model *MiPU*, which determines the minimum-cost power plant dispatch. In parallel, the *FLEX-GOLD* model calculates the load in a low-voltage grid and determines grid investments. In the final step, household electricity prices are calculated based on the models' results for the assumed scenarios with regard to charging power and local EV penetration rates.

This paper is structured as follows: In the next section, we discuss the existing literature. We then describe the applied method and the models used. Section 4 contains the framework conditions, i.e., a market diffusion scenario for EVs, the assumed charging behaviour of users of EVs, and the assumed influence of different charging powers on mobility. Based on the developed case study, we simulate the possible effects of EVs on electricity generation prices and grid charges in Section 5. We examine two scenarios with controlled and uncontrolled charging, each with three different cases of charging powers of the EVs. Then, we analyse the impacts on the overall electricity price for households. We draw conclusions in the final section.

2. Background

The literature on integrating EVs into the electricity system relevant for this paper can be divided into three different streams: The interaction of EVs with volatile RE and the resulting charging strategies, impacts on the electricity supply side and greenhouse gas emissions, as well as local electricity grid effects.

In the first stream, controlled charging of EVs, in more general terms (i.e., for the whole demand side) also referred to as demand response (DR) [7], and its implications on the electricity system is investigated: Dallinger et al. [8] examine the interactions between volatile RE and the charging process of EVs for Germany and California (also for 2030). They simulated different charging strategies – variable time-of-use tariffs and dynamic real-time pricing tariffs – to analyse what advantages these have for integrating RE. It was shown that uncontrolled charging of EVs results in a load peak in the evening, while controlled charging and real-time pricing, in particular, reduce this peak and integrate additional RE by shifting the charging process to hours with negative residual load³ [8]. Jochem et al. [9] calculate the effects of EVs in Germany, above all against the backdrop of greenhouse gas emissions. They analyse four different metrics to quantify the CO₂ emissions of EVs, which includes calculating an hourly electricity merit order curve. The authors conclude that it is possible for EVs to cut CO₂ emissions, but that, in addition to the calculation approach used, the country's supply portfolio and the possibility for controlled charging have a strong influence on the results [9]. Lund and Kempton [10] describe similar results with regard to reducing CO₂ emissions in a scenario based on the Danish energy system. As well as the already mentioned charging strategies, they additionally take into account charging at night and the vehicle-to-grid concept, where electricity is fed back into the grid from the vehicle battery. The latter was identified as the most favourable option for integrating RE alongside real-time pricing (referred to as "intelligent charging" in this study) [10]. However, some studies (e.g. Refs. [11–13]) also take a critical view of vehicle-to-grid concepts

³ Residual load in this context as well as in the context of our paper is defined as total hourly electricity demand minus electricity generation from volatile RE.

because of the associated high battery degradation.

While the cited studies mainly focus on the systemic benefits of EVs in general, and on controlling the charging process in particular, other studies are already developing economic approaches to incentivise charging behaviour that is beneficial to the system as a whole, for instance by participating in system services (e.g. Refs. [14,15]).

A large number of studies have already considered the consequences of a high penetration of the electricity market by EVs. While EVs are only used within a power plant deployment model as a medium to address further issues, e.g., CO₂ emissions, in Refs. [8–10], others explicitly address future impacts of EVs on power plant dispatch and electricity prices in Germany [13,16,17], Denmark [18] as well as Sweden, Norway, Denmark and Germany [11].

Taljegard et al. [11], who combine a generation capacity investment model with a power plant dispatch model, demonstrate that particularly for a high share of EVs, system costs due to investments in generation technologies increase. The simulations by Hanemann and Bruckner [13] show that the additional demand due to EVs leads to increased demand peaks and correspondingly to an increase in the marginal costs of electricity generation. Controlled charging dampens this effect. By shifting the load to hours with a low electricity price, technologies with low variable costs, especially lignite-powered plants, achieve higher full-load hours in the analysed studies [9,11,13,17]. This results in lower prices than in the uncontrolled case.

While the influence of EVs on prices is consistent in the studies we found, it must be noted that the impact of controlled charging on CO₂ emissions seems less clear and less comparable. According to Göransson et al. [18], controlled charging reduces CO₂ emissions, while Schill and Gerbaulet [17] report increasing emissions (due to an increased use of lignite). Jochem et al. [9] observe no effect at all (case "annual average mix"). The resulting differences are most likely induced by the respective framework scenario (e.g., Göransson et al. look at Denmark, Jochem et al. and Schill and Gerbaulet at Germany) or the features and parameterisation of the models: Schill and Gerbaulet [17] and Jochem et al. [9] both use existing but different scenarios for capacity expansion, i.e., the structure of the electricity system cannot be adapted to the new conditions due to the diffusion of EVs and do not consider cross-border flows. However, Jochem et al. [9] uses a power flow model, i.e. the electricity grid is modelled in high detail, while other aspects such as ramping of power plants are not considered. Hanemann et al. [16] demonstrate that depending on the underlying CO₂ price and resulting fuel switches, effects of controlled charging on emissions can be either positive or negative. Additionally, all papers possess slight differences regarding the diffusion of EVs and the modelling of controlled charging and the consideration of flexibility options.

The implications of EVs for electricity grids, especially low-voltage grids, are unclear as well. This is probably due to the heterogeneity of low-voltage grids in terms of age and settlement structure. One study on the impacts of the diffusion of PHEV in Ontario, Canada, calculated that penetration up to 10.5% has hardly any effect on the stability of the power grids [19]. Meanwhile, in a case study for a generic distribution grid in Great Britain, Papadopoulos et al. [20] arrive at the result that sporadic overloads occur at transformers at this level of penetration, but that voltage range deviations are only present to a large extent if the local stock of vehicles has higher shares of EVs.

Other studies have analysed the influence EVs might have on grid expansion in Germany. These studies generally vary in their methodological approach and distribution grid configuration or supply region and the market penetration rates of EVs. Nobis [21] concludes that no problems should occur at local grid transformers if charging powers at home are limited to 3.7 kW, even with 100% market penetration of EVs. Lower levels of market penetration permit a much higher charging power. The study emphasises the positive role of reactive power control for integrating EVs into electricity grids.

Liu [22] concludes that the configuration of the German medium-voltage grids and their subordinate low-voltage grids is

generally sufficient in small towns. As a result, EVs cause hardly any technical problems here. If the grids in larger towns or rural areas have weak points, grid reinforcement measures should be deployed. If an overload occurs at a local transformer, its annual lifetime consumption increases significantly. This can, according to Liu [22], only be eliminated if the batteries of EVs can be charged in a controlled manner.

Friedl et al. [23] point out that controlling the charging of EVs means that hardly any grid investments are needed up to 2030 in Germany, even when assuming higher market penetration rates of EVs.

While it can be assumed that the impacts of EVs on electricity grids depend heavily on the local framework conditions, the positive effect of controlled charging to avoid grid congestion seems very clear-cut (see Refs. [20,24]).

Various studies deal specifically with the demand for additional grid investments that may be caused by charging EVs. Robinius et al. [25] quantify the investments in all grid levels at around 17.5 billion EUR for Germany if 50% of passenger cars were electrified (approx. 20 million vehicles).⁴ A study by Oliver Wyman [23] calculates the investments required only for the distribution grids for the same rate of electrification at 11 billion EUR with uncontrolled charging of the vehicles. A recent study by McKinsey [26] also highlights the possible high investments in distribution grids due to EVs.

Overall, studies cover many aspects with regard to the impact of the diffusion of EVs into the electricity system. Yet, they have in common that they focus solely on one electricity cost component at a time. To the best of our knowledge, so far, there has been no analysis of what impacts EVs might have on the retail electricity price as a whole. This requires a holistic analysis of the market diffusion of EVs, the resulting impacts on the merit order of the electricity market and the local implications for low-voltage grids. In this paper, we address this research gap for Germany. We use the development of the German residential electricity price as an indicator for this analysis.

In order to illustrate the individual influencing variables, Fig. 1 shows the cost components of the German residential electricity price for the year 2018. They consist of procurement costs, network charges, concession fee, renewable surcharge, taxes and other surcharges. In this paper, we analyse implications of EVs on network charges and procurement costs, which are, apart from the renewable surcharge, the largest components of the household electricity price. Under the current

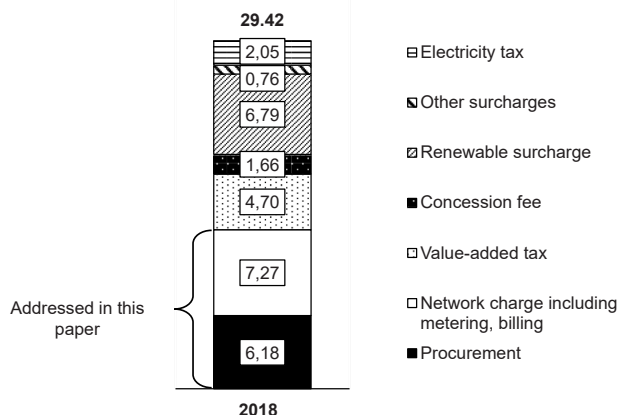


Fig. 1. Average electricity price for a household in EUR ct/kWh in Germany in 2018 – electricity price for a household with an annual consumption of 3,500 kWh (data from Ref. [27]).

regulations in Germany, all relevant price components are largely variable, i.e., they are calculated based on the kilowatt-hours of electricity consumed. As indicated above, EVs can significantly affect the demand for electricity, and this implies that EVs can exert a strong influence on the different electricity price components. In addition, the load profile of EVs is not distributed evenly throughout the day. This raises the question of how this will affect the electricity generation structure.

While using kilowatt-hours to calculate the procurement of electricity largely corresponds to the real cost structure, this is only the case to a limited extent for the other electricity price components. For example, more than 90% of grid costs are fixed costs. These costs are paid by grid users via the so-called specific grid charge,⁵ which is billed to consumers through the amount of electricity drawn from the grid. Improved utilisation of the electricity grids due to EVs could lead to a reduction of the specific charges and therefore to a reduction of electricity prices and in turn to economic benefits for electricity consumers.

3. Methodology

3.1. Market diffusion and charging behaviour

The market diffusion model *ALADIN* [28] is used to simulate the EV market diffusion and charging behaviour. *ALADIN* does not use empirical data for charging profiles because, at present, there are not enough representative data available for future charging behaviour with different infrastructure options (at home, at work, public). Instead, *ALADIN* simulates the future diffusion of EVs and their charging behaviour based on driving patterns of conventional vehicles [29,30]. A detailed description of the model is found in Refs. [31,32] and left out in this paper as we focus on the impact of EVs on the distribution grid and power generation.

3.2. Modelling the influence of electric vehicles on the system load and spot market prices

A comprehensive assessment of the effects of EVs on the electricity system requires analysing their influence on the distribution grid. Beyond local effects, the evaluation must also include the consequences at national level. This concerns the impacts on the structure of total electricity demand and the system load as well as the generation structure and the costs for electricity.

To analyse the effects of EVs at national level, the demand for electricity is modelled with hourly resolution and projected to the year 2030. The first step assumes an uncontrolled load of EVs. In a second step, the charging of EVs is controlled. This approach is able to identify and analyse the impacts on the system load. In parallel, effects on the electricity supply side are quantified by modelling the electricity generation needed to cover the load with and without EVs (for both uncontrolled and controlled charging).

The simulation model *eLOAD* is applied to the process steps listed and coupled with the fundamental model *MiPU*. *eLOAD* (“Energy Load Curve Adjustment Tool”) consists of a projection module and a DR/controlled charging module. In the former, the historical system load is disaggregated on the basis of a technology-specific process load curve database with an hourly resolution, and the process load curves are scaled individually using annual, process-specific demand projections for 2030. The process load curves for 2030 are subsequently re-aggregated to obtain the system load. This approach implicitly takes into account technological change with structural impacts on the system

⁵ Network charges for “load-profiled”, larger grid users in Germany (>500 kW) comprise a capacity price and a price per kWh according to the German regulation [27]. Users with a lower consumption (e.g., households at the low-voltage level) instead have to pay a price per kWh and a fixed basic rate instead of a power price.

⁴ For BEVs with a battery capacity of 75 kWh.

load. A detailed description of the model is found in Refs. [33,34].

In the DR module of *eLOAD*, there is the possibility to assume that the load of suitable processes, in our case privately used EVs, is flexible and suitable to optimise its use for controlled charging. *eLOAD*'s DR module has already been presented in Gnann et al. [34]. However, for the sake of consistency but particularly to present the linkage between DR modelling using *eLOAD* and electricity generation modelling with *MiPU*, we consider it necessary to briefly describe this part of the methodology as well.

The total load of EVs is allocated in a mixed-integer cost minimisation. Equation (1) shows the objective function for one optimisation interval, in which the costs for the electricity demand $P_{ls,i,j}^{EV}$ of EVs are aggregated and minimised:

$$\text{Min} \sum_{i=h_{\min}}^{h_{\max}} \sum_{j=h_{\min}}^{h_{\max}} P_{ls,i,j}^{EV} \cdot (p_j - p_i), \quad i \neq j, \quad i, j \in [h_{\min}, h_{\max}] \quad (1)$$

Here, the flexible load $P_{ls,i,j}^{EV}$ (MW), shifted from hour i to hour j depends mainly on the price signal p_j . To calculate implications of DR ex-post and to promote as much load flexibility as possible, we assume that for EVs, load shifting is not associated with additional costs (e.g., activation costs for each load shift or costs due to a consumption increase). We use the residual load, which is calculated endogenously within *eLOAD*, as DR signal p . We further assume that the electricity demand has to be supplied on each day, i.e., loads cannot be shifted from one day to the next. This means, as we use the yearly structure of 2012, that we have 366 optimisation intervals of 24 hours. As long as the vehicles' electricity demand is supplied on time for the next trip, it is assumed that the charging load of each vehicle can be controlled for the entire time interval in which the EV is connected to the grid.

There are no costs associated with shifting loads. However, load adjustments are restricted by load bounds, defined in Equation (2) and ensuring that the sum of hourly load (original load in an hour, P_i^{EV} , and load shifted to this hour, $P_{ls,i,j}^{EV}$ minus load shifted away from hour i , $P_{ls,i,j}^{EV}$) stays between the minimum and maximum load P_{\min}^{EV} and P_{\max}^{EV} (MW), respectively.

$$P_{\min}^{EV} \leq P_i^{EV} + \sum_{i=h_{\min}}^{h_{\max}} P_{ls,i,j}^{EV} - \sum_{i=h_{\min}}^{h_{\max}} P_{ls,i,j}^{EV} \leq P_{\max}^{EV}, \quad \forall i \quad (2)$$

Load shifting capacity also depends on the vehicles' storage and the fact that EVs are mobile, which means that three states - connected, mobile and disconnected - and the corresponding vehicle shares for each hour ($vs h_{conn,h}$, $vs h_{mob,h}$, $vs h_{disconn,h}$) are distinguished in order to determine the realistic load shifting potential available.

The available storage capacity for EVs is restricted by the total storage capacity SFL_{\max} (MWh) and the minimum storage fill level SFL_{\min} multiplied by the share of vehicles in the connected state.

Charging is only possible for vehicles in the connected state. Thus, the storage capacity available for load shifting (see Equation (3)) depends on charging (planned (P_h^{EV}), and due to load shifting away from ($P_{ls,h,j}^{EV}$) or to an hour ($P_{ls,j,h}^{EV}$)) and additionally on the energy withdrawn from the aggregated available storage (or fed in) if vehicles change from a connected to a mobile state $vex_{conn-mob,h}$ (vehicle exchange vex in MWh). Their storage fill level is then no longer included.

$$\begin{aligned} & SFL_{\min} \cdot vs h_{conn,h} \\ & \leq \sum_{h=h_{\min}}^i P_h^{EV} - \sum_{h=h_{\min}}^i \sum_{j=h_{\min}}^i P_{ls,h,j}^{EV} + \sum_{h=h_{\min}}^i \sum_{j=h_{\min}}^{h_{\max}} P_{ls,j,h}^{EV} \\ & - \sum_{h=h_{\min}}^i vex_{conn-mob,h} \leq SFL_{\max} \cdot vs h_{conn,i}, \quad \forall i \end{aligned} \quad (3)$$

Analogous to Equation (3), (4) and (6) restrict the storage fill level for mobile and disconnected vehicles. In each optimisation interval (24 h), the storage fill level (in the mobile case (Equation (5)) has to be equal

to the electricity exchange resulting from the transfer of vehicles from mobile to disconnected $vex_{mob-disconn,h}$ and the discharge load per hour $P_{dis,h}^{EV}$.

$$\begin{aligned} SFL_{\min} \cdot vs h_{mob,h} & \leq \sum_{h=h_{\min}}^i vex_{conn-mob,h} - \sum_{h=h_{\min}}^i vex_{mob-disconn,h} - \sum_{h=h_{\min}}^i P_{dis,h}^{EV} \\ & \leq SFL_{\max} \cdot vs h_{mob,h} \end{aligned} \quad (4)$$

$$\sum_{h=h_{\min}}^{h_{\max}} vex_{conn-mob,h} - \sum_{h=h_{\min}}^{h_{\max}} vex_{mob-disconn,h} - \sum_{h=h_{\min}}^{h_{\max}} P_{dis,h} = 0 \quad (5)$$

$$\begin{aligned} SFL_{\min} (1 - vs h_{conn,h} - vs h_{mob,h}) & \leq \sum_{h=h_{\min}}^i vex_{mob-disconn,h} \\ & \leq SFL_{\max} (1 - vs h_{conn,h} - vs h_{mob,h}) \end{aligned} \quad (6)$$

For disconnected vehicles, the energy in storage at the beginning of an optimisation interval again has to be equal to the beginning. Thus, disconnected vehicles are constrained by:

$$\sum_{h=h_{\min}}^{h_{\max}} vex_{mob-disconn,h} = 0 \quad (7)$$

The restrictions Equations (8), (9) and (10) ensure that the available storage capacity is considered for all exchanges between storage groups:

$$- SFL_{\max} \cdot vs h_{conn,h} \leq vex_{conn-mob,h} \leq SFL_{\max} \cdot vs h_{conn,h} \quad (8)$$

$$- SFL_{\max} \cdot vs h_{mob,h} \leq vex_{mob-disconn,h} \leq SFL_{\max} \cdot vs h_{mob,h} \quad (9)$$

$$- SFL_{\max} (1 - vs h_{conn,h} - vs h_{mob,h}) \leq vex_{mob-disconn,h} \quad (10)$$

This formulation results in a load shifting potential for EVs that takes technical restrictions into account. It generates an adjusted system load, which serves as input for the models *MiPU* and *FLEX-GOLD*.

The fundamental model *MiPU* (Minimal Cost Allocation of Power Units) calculates a merit order within the system boundaries of Germany with hourly resolution. The hourly demand for electricity modelled with *eLOAD* is used as input with and without controlled charging of EVs. This is covered by the available generation technologies, whereby the power plant-specific marginal costs $C_{k,h}^{var}$ of power plant k are calculated for the respective power plant capacity (P_k). The calculation considers the costs for fuel ($p_{k,h}^{fuel}$) and CO₂ allowances ($p_h^{CO_2}$), the type and age of the power plant ($\eta_k(t_{in}, k)$) as well as ramp-up times, ramp-up costs ($C_{k,h}^{st}$) and downtimes (see Equation (11)).

$$C_{k,h}^{var} = \frac{1}{\eta_k} \cdot P_{k,h} \left(p_{k,h}^{fuel} + p_h^{CO_2} \cdot e_k^{CO_2} \right) + C_{k,h}^{st}, \quad \forall k, \forall i \quad (11)$$

The demand and the electricity feed-in from PV and wind power are determined exogenously. The price-setting power plant, i.e., the plant with the lowest running costs, is then determined for every hour. This is done by calculating the minimum power plant capacity needed to cover the demand (D), which is transferred from *eLOAD*, minus feed-in from RE (P_{RES}) (see Equation (12)):

$$\sum_{k=1}^K P_k \cdot on_{k,h} \geq D - P_{RES}, \quad \forall h \quad (12)$$

Taking default probabilities into consideration, the binary variable $on_{k,h}$ is used to determine whether a power plant is deployable for the hour h in question. The hourly price on the spot market therefore corresponds to the marginal costs of the most expensive power plant needed to cover the load in an hour.

3.3. Simulation of the effects on electricity distribution grids and grid charges

Empirical surveys of today's charging behaviour and studies of potential future charging show that the majority of EVs in Germany – 80%–90% - are charged at home (e.g. Refs. [35,36]). This raises the question of what effects EVs have on the low-voltage grid (distribution grid).

The investments resulting from grid expansion are passed on to final consumers in the distribution grid through the specific grid charges. The specific grid charges account for about 23% of the electricity price for households and therefore strongly influence this price (see Fig. 1). The effects of EVs on the low-voltage grid are analysed using the *FLEX-GOLD* (Flexible Grid and Stakeholders) model. *FLEX-GOLD* conducts load flow calculations of electrical low-voltage grids on a quarter-hourly basis. In order to be able to model the load on the distribution grid in 2030 as realistically as possible, a simulation is carried out of household load profiles, the driving and charging behaviour of EVs and the electricity feed-in from decentralised PV, which, alongside EVs, will determine the grid load in the future. This model also implements an algorithm to depict the grid investments needed if grid overloads occur, for example, due to charging EVs. In line with [37], a distinction is made between voltage-related and thermal overloads. Voltage-related overloads are defined as a voltage deviation at a grid node of more than $\pm 4\%$ of the nominal voltage. If there is a voltage-related overload, an additional cable from the local grid transformer to approximately⁶ the last third of the overloaded line is installed endogenously. A thermal overload occurs if the electrical power exceeds the nominal power of equipment operated in the grid. In case of a thermal overload, a new cable is added from the local grid transformer to approximately⁶ the middle of the overloaded line. The algorithm in detail is publicly accessible (see Ref. [38]).

The weighted average costs of capital (WACC) are determined for the economic assessment of grid investments. These apply a mixed interest rate from the return on equity of the distribution grid operator and the return on borrowed capital. The capital costs are distributed over the lifetime of the used equipment using the annuity method. Changes in the grid charges can then be calculated from this.

4. Case study and framework

The analysis is conducted for Germany. The year 2030 is selected for the calculations because the transformation of the energy system and the diffusion of EVs and other sector coupling technologies are already well advanced by then.

We use a set of two cases each containing three different alternatives in terms of charging power in this analysis (see Table 1): Case A (i.e., A.1 - A.3), where charging of EVs takes place in an uncontrolled manner and Case B (i.e., B.1 - B.3) in which EV charging is controlled by a DR signal described in Section 3.2. For both cases, we focus on EVs with charging possibilities at home and at work, which only differ by the available

Table 1
Description of cases for uncontrolled and controlled charging and charging power.

Case		controlled charging	charging power
A	1	no	3.7 kW
	2	no	11 kW
	3	no	22 kW
B	1	yes	3.7 kW
	2	yes	11 kW
	3	yes	22 kW

⁶ Cables are only being added between existing nodes of the grid.

charging power. The charging powers under consideration are 3.7 kW (Cases A.1 & B.1), 11 kW (Cases A.2 & B.2) and 22 kW (Cases A.3 & B.3). In addition, only privately owned passenger cars are considered when simulating controlled charging of EVs, i.e., fleet vehicles are not taken into account. However, fleet vehicles are included in the projection of the system load. We refer to Ref. [34] for more information on the additional possibility of public charging points as well as other market diffusion parameters.

4.1. Assumptions for simulating controlled charging and modelling power plant deployment

The annual demand of specific processes used to model electricity demand and generation as well as the feed-in from RE, the power plants used, and fuel and CO₂ prices are taken from Ref. [39]. Table 2 gives an overview on key assumptions for different electricity generation technologies and the price for CO₂ certificates. Electricity imports are not considered. See Ref. [40] for the electricity demand in the year 2012, which is used for the projection of the system load.

Furthermore, all scenarios assume that the full load of private EVs is flexible. However, restrictions arise on the one hand due to where the EVs are located and, on the other hand, due to the battery size and charging limits for the charging process. We assume that on average 15 kWh per EV are usable for load shifting, which is equivalent to half of the usable battery capacity of BEVs (90% of 40 kWh) and PHEVs (80% of 10 kWh). We assume that only half of the potential battery capacity is used to still be able to perform all trips per user (cf. [34]). Charging limits are case-specific (see Table 1). The electricity demand caused by EV charging is taken from the market diffusion results (Section 5.1). For reasons of consistency, this demand is assumed to be equal for all cases.

For EVs, charging at home and at work is permitted. Conversely, this means that, within the framework of simulating controlled charging, the electricity demand of EVs can be shifted if these are at home or at the workplace as long as the demand for the next trip is covered.

4.2. Assumptions for electric vehicles in a suburban low-voltage grid

In the following, the assumptions for household, PV and EV profiles and scenarios are presented and the test grid used is described.

We assume a suburban area with detached houses and an average of 2.5 persons per household. The annual electricity consumption is 5,000 kWh per household [43].

For PV penetration, we assume that 500 MW of PV rooftop capacity will be installed annually in Germany until 2030 [44]. Calculated for the analysed grid, this corresponds to 60 kW_p installed PV capacity. It is spread across ten PV systems, each with an installed capacity of 6 kW_p [44]. The capacity of each PV system is limited to 70% of the maximum system to comply with the current German Renewable Energy Sources Act [45].

In Section 3.1 we model the national penetration of EVs, which is used as input parameter for the calculation of the electricity procurement costs. Nonetheless, independently of the national penetration of

Table 2
Technology-specific capacity, fuel and carbon prices. Source: [41,42].

	Installed capacity in GW	Fuel costs
Lignite	9.3	3.7 EUR/MWh _{th}
Hard coal	13.5	14.7 EUR/MWh _{th}
Open cycle gas turbine	5.7	39.6 EUR/MWh _{th}
Combined cycle gas turbine	11.7	39.6 EUR/MWh _{th}
Biomass	8.3	–
Wind onshore	38.3	–
Wind offshore	15	–
PV	52	–
Others (RE + conventional)	7.1	–
CO ₂ certificates	–	15.0 EUR/t

EVs in 2030, it is possible that charging of EVs (i.e. ownership of EVs) is very concentrated on individual areas and in consequence on individual grid lines. For this reason, we vary the penetration of EVs in the low-voltage grid in order to depict different penetration scenarios in addition to the cases described in Table 1. We define penetration as the proportion of EVs in the analysed grid. We explore scenarios where EVs (including BEVs and PHEVs) account for 5%, 10%, 20% and 30% of all vehicles.⁷

The number of EVs present in the grid plays a large role when planning and designing electrical distribution grids. If there is a low number of EVs, simultaneous charging and therefore a high simultaneity of charging processes must be expected. If the number of EVs in the grid increases, diversification effects occur, which reduce the simultaneity factor [46]. The maximum simultaneity factors assumed here are between 30% and 75% depending on charging power and penetration (see Fig. 2). The maximum simultaneity is also influenced by the charging power, because different capacities lead to different charging times for the same daily mileage. We also assume that each EV is plugged in once per day at home in the evening after the last trip of the day.⁸ To determine the time of charging, the hourly cumulated load profiles of all EVs in Germany from the *eLOAD* model are first converted to quarter-hourly profiles using a spline interpolation. They are then used to determine a probability distribution for whether an EV is currently charging. Based on this distribution and taking into account the maximum simultaneity factors, the charging times of the EVs are determined. The duration of charging depends on the daily distance driven.

Since a large number of EVs is mainly charged at home in the evening after the last trip of the day on weekdays, there is a high correlation between the households' load peak (19:15) and the maximum load of EVs.

In Case B, we analyse controlled charging of EVs. Under controlled charging, the households' peak load (19:15) and the maximum power consumption of EVs no longer occur in the same time range as in the non-optimised Case A. We assume, in the optimised Case B, the charging load of the EVs is shifted in time but being kept at the same charging point.

The analysis is conducted based on a suburban low-voltage grid in 2030. This type of grid is selected as typical because studies of today's users of EVs or those interested in buying one show that they tend to live in small towns or rural surroundings [47–49]. Grid structural data from Germany are used for the grid parameters [50]. Each cable is roughly 28

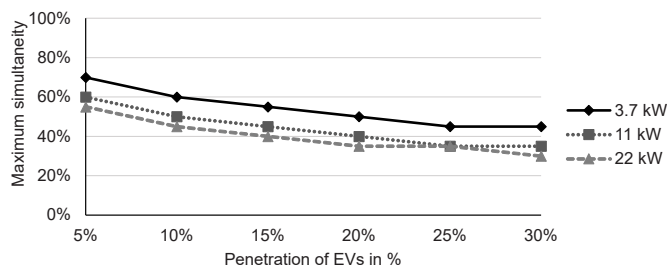


Fig. 2. Maximum simultaneity for different charging powers and EV penetration (mean value derived from Refs. [21,46]).

⁷ The national penetration rate for EVs in 2030 is approx. 10% (see Section 5.1). Local penetration naturally differs from the average national penetration. Therefore, this represents a range of possible local penetration rates for the near future.

⁸ The simulations assume that charging at the workplace is done in a different low-voltage network. For the load flow calculations, we only consider charging at home.

m long. This corresponds to the average length of low-voltage cables and lines in regions with average population density in Germany [44]. The grid is supplied by a 630 kVA local transformer and consists of four lines, each with 25 nodes. The main grid parameters are summarised in Fig. 3.

Every grid node supplies one household (detached house) with electricity. The PV systems and the EVs are assigned stochastically to the nodes. The nodes are connected with each other with NAYY-J cables with a conductor cross-section of 150 mm².

For the case examined, it is assumed that the distribution grid operator uses 40% equity capital for the investment with an interest rate of 6.91% (before tax) [51]. The remaining borrowed capital has an interest rate of 2.72% (in accordance with the German Electricity Grid Fee Regulation Ordinance [52]). With the mixed interest rate, the capital costs are spread over 40 years, since this is the minimum regulatory depreciation period for these cables (see Ref. [52]).

5. Results

5.1. Market diffusion and charging behaviour

The three analysed charging powers in Case A lead to approx. four million EVs in 2030, which corresponds to about 10% of the stock of all passenger cars. These vehicles require 11.6 TWh of electricity in 2030. In addition, this results in a very similar load profile for all analysed charging powers, which is illustrated in Fig. 4. The different capacities have hardly any influence on the market diffusion or load profile in the quarter-hourly analysis intervals.

Fig. 4 shows the load profile of several vehicles over the course of a week, which is assumed to be representative for a typical vehicle. The black areas show charging at home, the grey ones charging (of privately owned EVs) at work. Charging at home shows a peak in the early evening hours on weekdays, when many cars are charged after work. Charging at work reduces the evening peak on weekdays but creates an additional peak in the morning hours once the vehicles have reached the workplace. At the weekend, the load curve is flatter and spread over the day. We use the aggregated load profile described here as a typical load profile for EVs in the further analyses. The average annual electricity demand of an EV resulting from our model is 2.9 MWh.

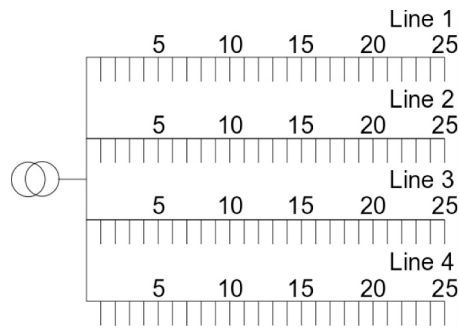
The further analyses also clearly show that increasing the charging power does not have any significant influence on the use of a BEV or PHEV. Several thousand driving profiles of vehicles that form the basis of the *ALADIN* model are examined with regard to the technical feasibility of a BEV and with regard to a PHEV's potential share of electric-only driving [29,30]. It is apparent from Fig. 5 that increasing the charging power neither leads to a clear increase in the proportion of vehicles that could be replaced by a BEV nor to an increase in the average share of electric-only driving in PHEVs. Hence, low charging powers are sufficient for everyday mobility needs from a techno-economical perspective.

So-called long-distance transport events are rare and require much higher charging powers (fast charging above 50 kW) [53]. These were not examined in this analysis because they are likely to occur in medium-voltage grids [54].

5.2. Effects of electric vehicles on the system load

An annual electricity demand of 446.4 TWh is assumed for 2030 [39]. Compared to today, this means a slight decrease in total electricity demand due to efficiency increases, especially for lighting in households and the trade, commerce and services sector. As a result, the hourly load decreases slightly, especially between 08:00 and 20:00. As seen in Fig. 4, the electricity demand for charging EVs is spread mainly across the period from 06:00 to 22:00. This effect has a corresponding influence on the structure of the system load as shown in Fig. 6.

Even when considering charging performed at work, there is an additional increase in the peak load in the evening due to the high



Grid parameter	Value	Unit
Transformer capacity	630	kVA
Total length of cables	2820	m
Conductor cross-section	150	mm ²
Cable length/household (hh)	28	m/hh
Grid lines	4	
Grid nodes	100	
Households	100	
PV systems	10	
EVs	variable	

Fig. 3. Topology of the suburban grid and the grid parameters used.

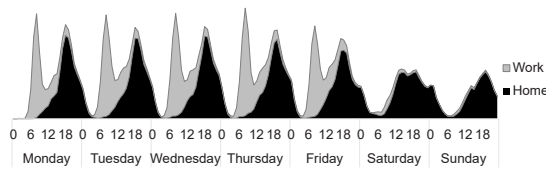


Fig. 4. Simulated load profile of private EVs in 2030 given charging possibilities at home and at work (here 3.7 kW (Case A.1)).

5.3. Controlled charging of electric vehicles

The previous section shows that, already in 2030, EVs represent a perceptible share of total electricity demand. Since, at the same time, EVs also have prolonged downtimes, during which charging power could be shifted, they are suitable for the application of controlled charging. Controlled charging in this paper is modelled in a way that creates an incentive for shifting charging to times of low residual load. Fig. 7 shows the aggregated result of optimising the load for Cases B.1 - B.3 (3.7 kW, 11 kW and 22 kW). It illustrates the change in the load of private EVs due to controlled charging. A negative load change results in the morning and from noon to 22:00. Thus, load is shifted away from these hours. Charging takes place instead especially at night between 23:00 and 05:00. This applies to all load levels of Case B.

Comparing Cases B.1 - B.3 shows that, the higher the applied charging power, the more pronounced the change between hours and the more this is concentrated on a smaller number of hours. This is due to the shorter charging duration at a higher charging power. Fig. 8 shows the systemic effects of the modified aggregated charging profile: Residual load peaks can be significantly reduced – by a maximum of more than 2 GW.

Controlled charging shifts some parts of the electricity demand into times when the residual load is low or there is even a surplus of RE generation, i.e., a negative residual load. This helps to integrate RE into the system, since they do not have to be dumped due to a surplus of supply in the market.⁹ In addition to this, Figs. 7 and 8 indicate differences resulting from the assumed charging power: Since the flexibility of EVs increases at higher charging power while still complying with the other technical restrictions, phases in which there is a high incentive for load shifting can be better exploited. This leads to higher change rates in the load profile of EVs and thus to higher maximum loads, but can be beneficial from a system perspective, because it smooths the residual

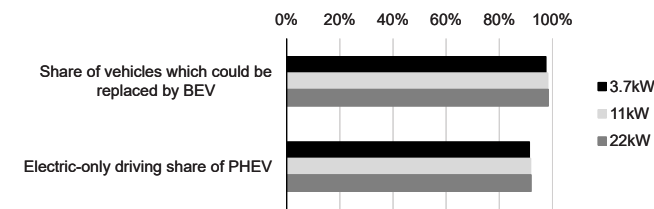


Fig. 5. Influence of charging power on the use of BEV and PHEV from a technical perspective with assumptions for 2030.

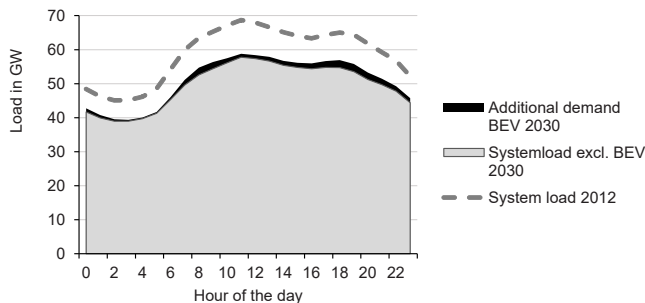


Fig. 6. Germany's average system load for 2012 (line) and 2030 (area) on an average day. For 2030 the black area shows the load of private EVs (Case A.1).

proportion of vehicles that are plugged in to charge directly after the last trip of the day. This peak is only slightly lower than the midday load peak. Overall, therefore, EVs alter the shape of the system load compared to today and shift it to hours around midday and in the evening. On average, the system load in 2030 (in Case A) increases by 1.3 GW due to private EVs. The different charging powers analysed in Cases A.1 - A.3 result in negligible differences from the hourly system load perspective.

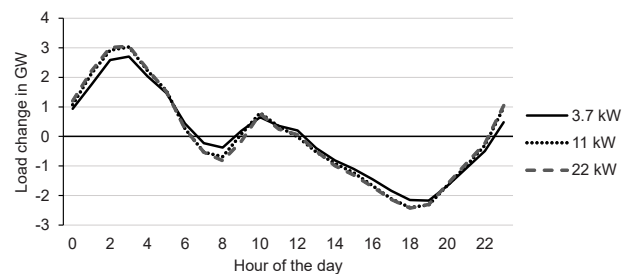


Fig. 7. Average change in the load of private EVs after controlled charging optimisation and considering charging power in 2030.

⁹ In the context of the German Network Development Plan, this - in contrast to grid related curtailment of RE - is called dumped energy [55].

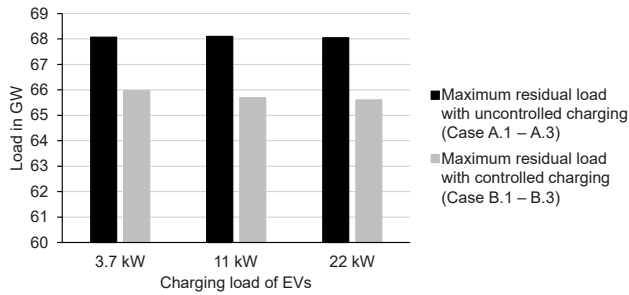


Fig. 8. Comparison of the maximum residual load of Case A and B for all charging powers considered in 2030.

load and thus reduces residual load peaks.

5.4. Effects of electric vehicles on electricity generation costs

In Section 5.3, we looked at the effects of EV diffusion on the structure of energy demand. Now, we turn our attention to the perspective of electricity generation.

The diffusion of private EVs – as already demonstrated – initially increases electricity demand by 2.7% by 2030 for the simulated market penetration. This additional energy demand requires additional electricity generation. Again, we point out that the national penetration of EVs used to calculate demand and the associated analyses of electricity generation is about 10% of the stock of passenger cars and is not varied.

Table 3 shows the change of the marginal generation costs of the model *MiPU*: For the Cases A.1–3 the average marginal costs of electricity generation increase by around 6% (volume weighted) due to the additional generation needed. If controlled charging is applied (Cases B.1–3), we only observe an increase of the average marginal costs of 3.8%. Overall, the cost increases in all cases also imply that the diffusion of private EVs also has an effect on all electricity consumers.

It is also relevant in this context that, although the marginal costs of electricity generation increase to a similar overall extent in the cases, there are slight differences concerning the increase. The largest increase takes place in Cases A.2 and B.2. The higher charging power (22 kW) in Cases A.3 and B.3 causes the aggregated load profile of all EVs to change so that it is slightly cheaper to purchase electricity.

We conclude that the increase in the marginal costs of electricity generation has a disproportionate impact relative to the additional demand in all cases. This is due to the fact that the uncontrolled load of EVs is not spread equally across the day, but increases disproportionately at certain times, especially around midday and in the evening. As a consequence, power plants with higher marginal costs are increasingly deployed, e.g., gas-powered plants (see Table 4). This circumstance leads to correspondingly high average generation costs. Overall, the additional demand of EVs leads to a higher use of all conventional power plants as shown in Table 4.

While varying the charging power of EVs between 3.7 kW, 11 kW and

Table 3

Change of average volume-weighted marginal electricity generation costs due to the diffusion of EVs before (Case A) and after controlled charging (Case B).

Case	Average generation costs in EUR/MWh	Change in % (reference: no EVs)
A 1	65.8	+6.0%
A 2	65.9	+6.1%
A 3	65.8	+6.0%
B 1	64.4	+3.8%
B 2	64.5	+3.8%
B 3	64.5	+3.8%
Without EVs	62.1	–

Table 4

Impacts of EVs and controlled charging (3.7 kW) of private EVs on electricity generation.

	Lignite	Coal	Gas
Increase in electricity generation due to the additional demand of EVs without controlled charging (Case A.1)	3.2%	6.5%	15.2%
Increase in electricity generation due to the additional demand of EVs with controlled charging (Case B.1)	5.7%	5.1%	7.0%
Net effect of controlled charging of private EVs: Case B.1 compared to Case A.1	2.5%	–1.3%	–7.2%

22 kW without DR (Case A.1–3) results in only minor effects on electricity generation costs, controlling their charging, (Case B.1–3) does lead to a noticeable change in the electricity generation structure as highlighted in Table 4.

Load shifting from the afternoon and evening into night-time or early morning hours results in a stabilisation of the system load. Consequently, power plants with higher marginal costs are deployed less frequently, which means a reduction in the electricity generated by gas (–1,830 GWh) and coal-powered plants (–926 GWh) and a higher capacity utilisation of lignite-powered plants (+1,455 GWh). In line with the results described by Hanemann and Bruckner [13], uncontrolled charging increases the marginal costs of electricity generation, especially in peak load hours. When controlled charging (Case B) is applied, the diffusion of EVs increases the marginal costs above all during low-price hours, but overall to a lower extent than is the case for uncontrolled charging (Case A). Our results show that not only average generation costs but also CO₂ emissions decrease due to controlled charging. CO₂ emission savings are particularly high for gas-fired (–10.8%) and hard coal power plants (–3.5%). Despite the increased use of lignite power plants as a result of DR, we observe a slight decrease of CO₂ emissions for this plant type (–0.4%), since more efficient plants are used and ramping is reduced.

5.5. Influence of electric vehicles on grid charges

In the following, the influence of EVs on grid investments is described first. This is followed by an evaluation of the influence of the additional electricity demand caused by EVs on the refinancing of the existing grid infrastructure.

For Case A.1, no investments in the low-voltage grid are required. With higher charging powers (Cases A.2 & A.3), investments of 61,000–65,000 EUR are required for the analysed grid region for all the examined rates of local EV penetration (see Fig. 9). This means investments ranging from 1,800 EUR (EV penetration rate of 30%) to 10,900 EUR (EV penetration rate of 5%) are needed per EV present in the grid. Our results show that rates of local penetration higher than 5% do not increase the need for grid expansion. This is due to the rising diversification effects of a larger number of EVs in the grid and the associated drop in simultaneity. In Cases B.1–3, there is no need for grid expansion and therefore for investments in the analysed distribution grid (see Fig. 9).

For the example low-voltage grid selected here, it can be stated that a low charging power (3.7 kW) or controlled charging can avoid investments in the grid.

Investments in the low-voltage grid resulting from grid expansion are largely passed on to the final consumers in a distribution grid via the price charged per kilowatt-hour, which is determined based on their annual electricity consumption (specific grid charges). In spite of possible higher investments in the distribution grids, however, increased grid utilisation actually lowers the grid charges, because these are then distributed across a larger amount of power withdrawn from the grid.

For the defined cases examined here, an additional electricity demand of 13.8 MWh per year occurs in the grid due to EVs if 5% of all

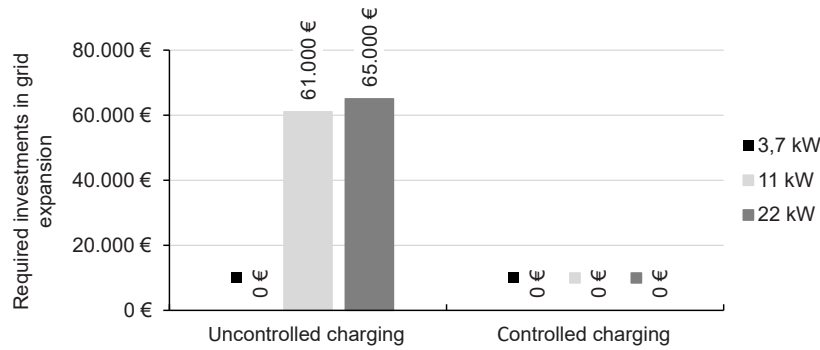


Fig. 9. Required investments in 2030 for the grid shown in Fig. 3 depending on the charging power (valid for all examined rates of local EV penetration).

vehicles are electric. If 20% of all vehicles are EVs, the demand for electricity increases by 50.5 MWh per year. At a very high degree of penetration (30% EVs), 77.8 MWh per year are needed additionally from the grid. Since a high share of the grid costs are fixed costs and only a very small share is variable, increased utilisation of the grids leads to decreasing specific grid charges.

Fig. 10 illustrates the change in the specific grid charges for the analysed scenarios that results from the combination of higher grid utilisation and the required grid expansion due to EVs. There is no need for grid expansion at a charging power of 3.7 kW in the analysed grid. For Case A.1, we observe decreasing specific grid charges for all the levels of EV penetration examined. The reductions range from 3% for a penetration rate of 5% EVs up to 14% for a penetration rate of 30% EVs. The same figures are found for Case B with optimised charging times, because there is no need for grid expansion here either – for all the cases and penetration rates analysed. In Case A.2, grid charges increase by 1% for a 5% EV penetration. This increase can also be observed for an even higher charging power of 22 kW (Case A.3). If the proportion of EVs rises to 10%, the specific grid charges decrease by 2% and 1%, respectively, for Cases A.2 and A.3 compared to the reference value. For the higher rates of penetration considered, the grid charges decrease with an increasing share of EVs in the grid by up to 11% (Case A.2), because the improved grid utilisation then outweighs the required grid investments.

Assuming that current regulations apply, we can therefore conclude for the analysed scenarios that the specific grid charges will decrease significantly in almost all cases due to EVs. Due to the declining grid charges, all households without EVs will also pay a lower amount for electricity overall. Although households with EVs require significantly larger amounts of electricity with a corresponding impact on their electricity bill, they also benefit from lower electricity prices.

The results of our study confirm the results of other current studies concerning the need for grid expansion (e.g. Refs. [21–23]). In addition to the results of these studies, our analysis also considers the effects on grid charges resulting from EVs. As well as the cost-increasing effects of necessary investments, specific cost reductions may also result if grid

utilisation is increased. As far as the authors are aware, this effect has hardly been investigated so far.

5.6. Synthesis of results: the effects of electric vehicles on household electricity prices

This study explored several effects considering the charging behaviour resulting from the given charging power. On the grid side, we additionally analyse to what extent the diffusion of EVs determines how the grid charges develop, taking into account the proportion of EVs within the described grid area. With regard to electricity generation costs, we analyse how the additional electrical load due to EVs influences the hourly electricity generation costs. Both aspects, the generation costs and the expenditure for grid expansion, were quantified for both controlled and uncontrolled charging. To compare the effects, the change in the electricity price is calculated in cents per kilowatt-hour for household customers (€/ct/kWh)¹⁰. Whereas electricity generation costs increase in all scenarios due to the additional electricity required for EVs, the diffusion of EVs results in locally decreasing grid charges even at a low level of local penetration (>=5%). The overall increase in electricity generation costs, illustrated in detail in Section 5.4, is lower than the change in the grid charge if the share of EVs is more than 10% (see

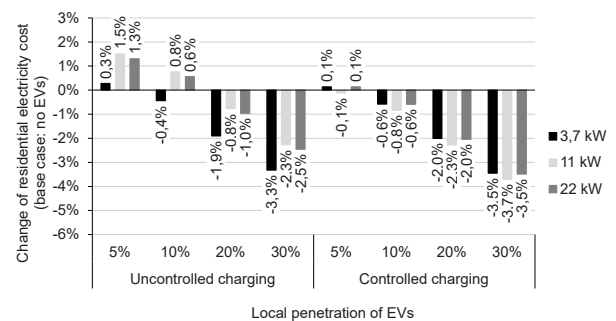


Fig. 11. Overall change in the electricity price for households, for uncontrolled and controlled charging in 2030.

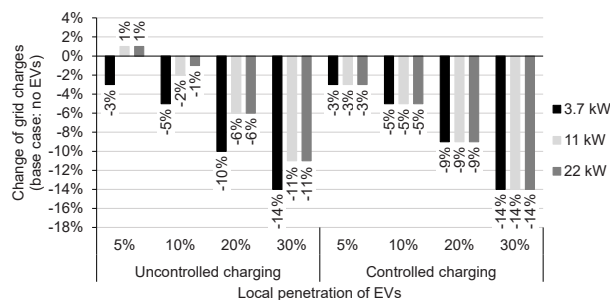


Fig. 10. Influence of additional electricity demand due to EVs on the grid charge in a suburban grid in 2030.

¹⁰ This includes the other electricity price components alongside the electricity generation costs and network charge. The basic assumption is that electricity is procured exclusively on the spot market, i.e., at the electricity generation cost calculated. We apply a renewable energy surcharge of 6 ct/kWh. 1.86 ct/kWh is assumed for the distribution costs and profit from electricity generation. This corresponds to the average sales costs assumed for household customers for 2010–2013 [56]. All other price components and the electricity tax are taken from Ref. [57] and assumed to be constant.

Fig. 11. This means that rising electricity generation costs are already overcompensated by falling grid charges at a low local diffusion of EVs. As a result, a household without an EV spends up to 3.7% less on electricity than is the case without EVs in the grid. A relative increase in the electricity price is only expected if there is a low local number of EVs.

Overall, it becomes clear that the penetration rate of EVs represents a significant factor for how the electricity price develops. In this context, we emphasise that the total (national) annual electricity demand of EVs remains constant in all the scenarios. The penetration rate is only varied locally in the distribution grid considered. **Fig. 11** also shows that the reduction of the household electricity price (at a penetration of $\geq 20\%$) is the lowest in Case A.2 (uncontrolled charging) and is the highest in Case B.2 (controlled charging). This effect, which was already addressed in section 5.4, is due to the charging profile of the EVs in the respective cases.

We emphasise that the charging control of EVs was conducted at national level with the objective of smoothing the national residual load, and that incentive or congestion signals from the analysed distribution grid were not considered. Nevertheless, the results show that controlled charging leads to EVs behaving in a way that benefits the overall system.

6. Discussion and conclusions

This study analysed the influence of electric vehicles (EVs) on two important electricity price components, the grid charge for the low-voltage grid and electricity procurement costs, for the price households pay for electricity.

Our study integrates a number of variations: We examined diffusion of EVs, generation costs and grid impacts for an EV charging power of 3.7 kW, 11 kW and 22 kW, with and without controlled charging and varied the local EV penetration in the distribution grid from 5% to 30%. In our view, the high amount of dimensions we chose enhance the robustness of our results. Yet, the four models applied several approximations: The existing scenario we used for the analysis of implications of EVs on the electricity generation costs was designed with a CO₂-reduction pathway of 80% until the year 2050. A more ambitious target would have gone along with more ambitious shares of renewables, leading to lower marginal electricity generation costs but also a higher volatility of generation and thus impacts on the local grid level as well. Political instruments, such as an accelerated coal-phase-out, would also affect the results, since it would improve the market position of gas-fired power plants - reducing CO₂ emissions but supposedly resulting in higher average generation costs. Additionally, as we focussed on the analysis of EVs, controlled charging of EVs was the only source of flexibility considered here. Considering other flexibilities, such as further demand flexibility options, storage, but also the integration of Germany's neighbours (i.e. cross-border electricity transport capacity) into the electricity market model could lead to lower generation costs, decreased CO₂ emissions and decreased volatility and thus could facilitate the integration of EVs into the electricity system. In this respect, studies examining higher shares of RES but also deeper levels of decarbonisation of the demand side and additional sources of flexibility could complement our findings.

Similarly, a much more comprehensive analysis could be conducted that considers all the effects of electric mobility. For example, this would include calculating the effects due to the decline in the demand for petrol and diesel and including the associated losses in tax revenue. This would also include considering the decrease in export expenditures for crude oil and the additional gains in value added and tax revenues from the additional electricity production in Germany. The effects due to changed value creation in automobile production would also have to be considered. Such an overall comprehensive analysis is complex and was beyond the scope of this study. It should be noted, however, that an analysis of comprehensive studies does not reveal a uniform picture and that the effects are strongly determined by the different assumptions. Having pointed that out, the several studies conclude that electric

mobility could have positive economic effects on Germany (e.g. Ref. [58]).

With reference to the calculations for the electricity distribution grid, our results show that relevant additional grid investments due to EVs only occur for the analysed supply area if high charging power (11 kW and over) and uncontrolled charging coincide. If charging EVs is controlled, no additional grid investments are needed in the cases examined up to a local penetration of 30% EVs. This finding confirms the results of other studies. However, it must be pointed out that the distribution grids in Germany vary widely in configuration and design, and charging EVs may also result in higher grid investments in individual cases. In addition, local EV penetrations of over 30% could occur in individual cases. The simultaneity of EV charging decreases with higher EV penetrations [21]. Nevertheless, violations of the grid restrictions may occur. Here, too, the effects are strongly dependent on the grid area under consideration. Further investigations into the influence of controlled charging at higher EV penetrations could provide insights here. Also, the future development of battery price and capacity can have large effects on EV market diffusion, but also on the shiftable loads. Higher capacities would allow more users to perform all their driving with a battery electric vehicle and also increase the potentials for load shifting. If the battery price development is not of the same magnitude, this could, however, also have negative effects on market diffusion, since investments would rise and battery electric vehicles could become less attractive. Future studies could analyse this aspect.

As far as the authors are aware, this study is the first to analyse the effect of EVs on both electricity generation and on the grid charge. The latter constitutes the biggest part of the electricity price for German households. Higher electricity sales due to EVs mean much better capacity utilisation of the electricity grid. On the basis of current grid regulations, this can significantly reduce the average specific household electricity price (in contrast to the effect on the cost of electricity generation).

If the two effects are taken together, the cost-reducing effects of the grid charge are usually larger and, in sum and depending on the assumed case, the specific electricity price for German households can be reduced by up to 4% in the most favourable case. This might be considered not very relevant, but in the context of the public discussion, in which there are frequent warnings about the possibly high grid investments required by EVs, our study can contribute to a more objective debate.

It can be concluded that controlled charging of EVs should be promoted and incentivised by the regulatory framework. Limiting the charging power can also make sense with a higher market penetration of EVs. In this context, it should also be considered whether the higher grid investments caused by a high charging power (22 kW and above) of households with EVs should be shared across all consumers. Alternatively, it could be discussed whether these costs should be borne solely by the users of the EVs or those with high charging power. However, such considerations should also include possible trade-offs with impacts on the market diffusion of EVs.

Future studies should also include the effects of EVs on the electricity transmission grids and the possible impacts of EVs on the renewable energy surcharge. Complementary studies of distribution grids are also suggested, because such grids are very heterogeneous and the effects of EVs can vary greatly. Furthermore, future research could also consider the influence of possible changes in how the grid charge is configured. A further issue that was not explored here concerns the effects of using public fast charging points on the electrical transmission and distribution grids.

Credit author statement

Matthias Kühnbach: Conceptualization, Methodology, Software, Formal analysis, Visualization, Data curation, Writing - original draft, review & editing. Judith Stute: Conceptualization, Methodology, Software, Formal analysis, Visualization, Data curation, Writing - original

draft, review & editing. Till Gnann: Conceptualization, Methodology, Software, Formal analysis, Visualization, Data curation, Writing - original draft, review & editing, Funding acquisition. Martin Wietschel: Conceptualization, Writing - review & editing, Funding acquisition, Supervision. Simon Marwitz: Conceptualization, Methodology, Software, Writing - review & editing. Marian Klobasa: Writing - review & editing, Funding acquisition, Supervision.

Declaration of competing interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

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