Effects of variable grid fees on distribution grids with optimized bidirectional battery electric vehicles

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Introduction

The ongoing electrification of the mobility and heating sector, which is a good possibility to reduce greenhouse gas emissions, leads to new flexible components in the energy system [1]. Especially, electric vehicles (EVs) with relatively high charging powers and large battery capacities can help to integrate renewables into the system [2]. Therefore, the EVs, with their high parking time of more than 23 hours per day [3], can be used as a storage if they are not only charged but also discharged, which is called bidirectional charging. Often the integration into the grid or energy system is also referred to as vehicle-to-grid (V2G) [4]. With bidirectional charging many different use cases, e.g., PV optimization, trading as well as grid services are possible [5]. The different use cases in addition to electrification also place new demands at the electricity grids, especially the low voltage grid, where most of the EVs are connected via charging stations at home or work [6].
To motivate customers to use or provide the flexibility of their EVs, this must be financially or at least environmentally profitable for them, if not mandatory. One possibility is to charge the own PV energy, whose production costs are below the price of electricity consumed from the grid. The electricity price in Germany can be divided generally in three main parts. First the procurement price, which reflects the producers' generation costs and is around 26 %. Secondly, the grid fees, which are incurred for the use of the public electricity grids and depend on both the grid level and the grid operator. On average the grid fees in the low voltage grid were 7.17 ct/kWh respectively 22 %. Thirdly, the taxes, levies and surcharges that are added represent 52 % [7]. Beside the procurement costs, the grid fees are one of the main cost components, and therefore analysed more in detail in this paper.
The grid fees today for typical consumers like private households are charged per kilowatt hour regardless of the current grid load. Thus, there is currently no incentive for customers to behave in a grid-serving manner. In the future, variable grid fees could help with the integration of new consumers as well as renewable energies. Different options for variable grid fees are discussed in literature [8], which can be summed up in three categories: time-based variable, congestion-oriented or dynamic fees linked to the electricity price. The following methodology focuses on congestion-oriented variable grid fees.

Keywords: bidirectional charging, electric vehicle, grid integration, distribution grid, flexibility, energy system analysis, variable grid fees

Methodology

The grid impacts of cost optimised EVs and storage units with variable grid fees were analysed using the distribution grid and energy system model GridSim. The model developed at FfE enables detailed simulations of low and medium voltage grids based on a load flow calculation [9], [10], [11]. An overview of the methodology combining the required input like low voltage grids, future scenarios, parameters, and use cases, the different function used inside the GridSim model as well as the output is shown in Figure 1Figure 1.
The analysis was carried out for 1206 real low-voltage **grids** from Bavaria (Germany) prepared in an upstream process representing a wide range of different characteristics e.g., to transformer size, line lengths and grid connection points (GCP). Additionally, today's load data was linked on a building level (same as GCP) including measured consumption for households, commercials and power-to-heat systems (PtH), like heat pumps (HP) and electric storage heaters (ESH), as well as with the known installed capacity of PV systems (PV). For customers with recording power metering, measured load profiles were used. [12]
To analyse the future grid load, regionalised **scenarios** for EV, PtH, PV and stationary battery storage (SBS) for the year 2040, which are based on today's grid allocation and had been developed according to the methodology published in [12], were used. Based on this scenario on average a building has 1.1 EV, 0.45 HP, 0.24 PV and 0.1 SBS within the analysed grids.

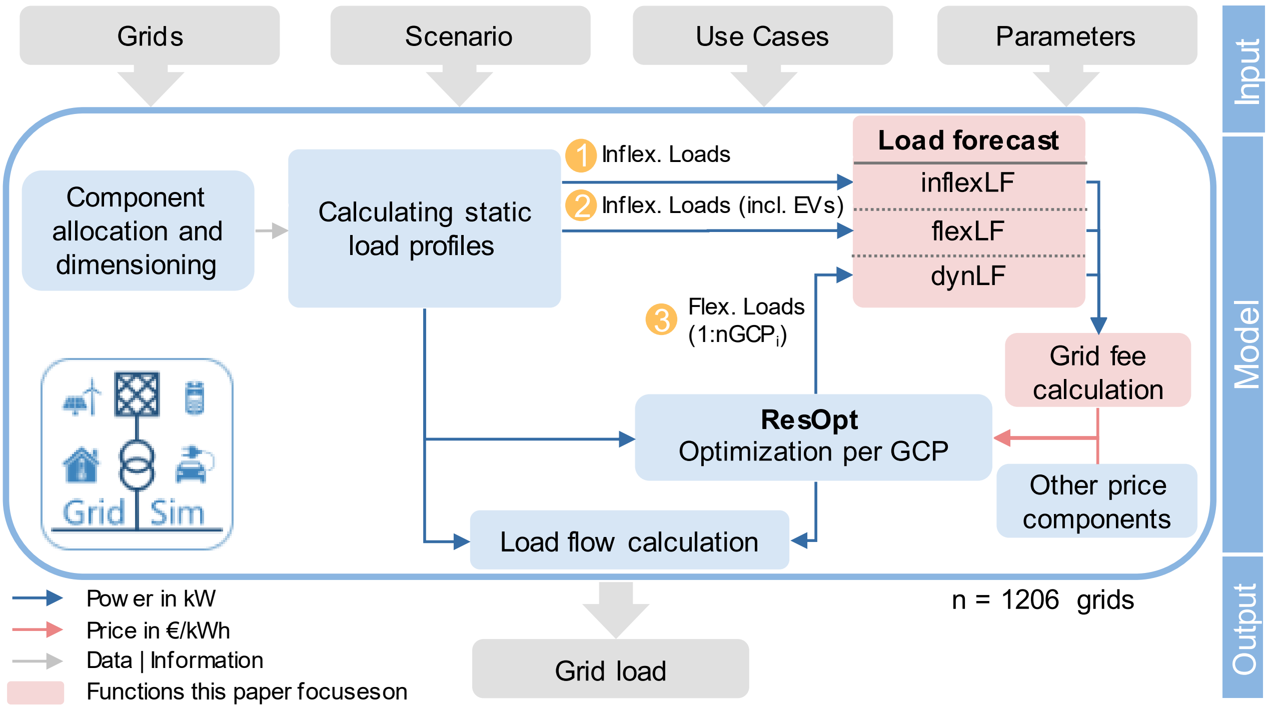

Figure 1 – Overview of the simulation model and the extensions for variable grid fees (red)

Based on energy system analysis and in discussions with experts, a mixed scenario regarding the usage of smart and bidirectional charging and the share of different use cases the following scenario was developed. 30 % of the GCP participate in **use cases** with bidirectional EVs and are therefore assumed to be flexible. At 17 % of the GCP (19 % of EV), a PV system and EV or SBS are present and self-consumption is increased (V2H). For V2H, consumers pay a fix price for electricity (24.38 ct/kWh) including the typical levies and taxes but without a fix grid fee of 5.05 ct/kWh and receive the EEG remuneration for electricity fed back into the grid (8 ct/kWh). The prices refer to the German electricity price design. The EVs and SBSs at the other 13 % of the GCP (17 % of EV) are given the opportunity for arbitrage transactions based on variable spot market prices for 2040 (described in [13]), so the EVs and SBSs can be charged and discharged back into the grid (V2G). In the case of V2G the EVs are considered like stationary grid storages in terms of taxes and levies (2.1 ct/kWh), which was described further in [14]. In addition, the grid fees are also compensated when feeding back electricity to incentivise grid-serving discharging in the V2G case. Just the 13 % GCP participating in V2G are subject to variable grid fees. Consumers of all other GCP behave in a demand-led manner or participate in V2H.

General **parameters** as well as parameters for dimensioning the components such as power and battery capacities are as documented in [14]. The most important parameters of the EVs are the charging and discharging power of 11 kW with charge and discharge efficiencies of 94 % (for 2040) and a battery capacity, which ranges from 38 kWh (26.6 % of the EV) to 60 kWh (40.6 %) and up to 100 kWh (31.8 %) due to different car classes [15]. Further on a simulation in 15-minute time steps for the weather and structure year 2012 was parameterised.

After defining grids, scenario, use cases and parameters a simulation is caried out for each grid, beginning with the **allocation and dimensioning of the components** and **calculating static load** profiles in the next step for households, commercials, EV, PtH and PV. In this case, SBS are only charged by the PV surplus. The methods these load profiles base on are described in detail in [14]. Additionally, further changes have been made to reproduce a more realistic electrical behaviour for EVs and PV systems.

Firstly, a state of charge (SOC) dependent plug-in probability model for EVs at home like described in [16] was implemented. In [17], the model has been extended to include a next trip consideration to ensure that mobility needs can be met. This module is only used for the demand-led charging strategies and therefore, the expectation value is set to 50 % in a normal distribution, with a standard deviation of 0.1 what leads to a realistic plug-in behaviour at SOCs around 50 % or lower. Furthermore, in the future scenario, all EV wallboxes and inverters of PV systems perform a voltage-dependent reactive power control (Q(V)) based on a defined characteristic curve. According to the technical connection specifications of the DIN VDE AR-N-4105 [18], grid operators can already demand Q(V) for newly installed PV inverters in low-voltage grids. For the simulation of the year 2040, it was assumed that Q(V) regulation will be standard for all PV and wallbox inverters.

The calculated static load profiles (Inflex. loads) based on a demand-led consumption pattern serve as input for the optimisation model ResOpt, secondly for the load flow calculation for GCPs without flexibilities and thirdly for the load forecast as well as the following grid fee calculation.

The cost optimisation is implemented within the **optimisation model ResOpt** as part of GridSim and used to determine the load profiles of flexible consumers like EVs and SBS by a linear optimisation at building level (GCP) [10], [11]. Therefore, three main price components are considered. Firstly, the price for the energy, which can either be fix or variable over time. Secondly, fees, levies and surcharges, which are added to the price, and thirdly, the grid fee, which is the focus of this paper.

To analyse the effects of load- congestion-oriented grid fees two modules were developed and integrated in the simulation model. One to predict the grid load (**Load forecast**) and a second to calculate the variable grid fee (**Grid fee calculation**). The **load forecast** module allows three different methods with increasing complexity to forecast the transformer load. The first method (inflexLF) is oriented on today's possibilities of grid operators to predict the transformer load based on historic measurements. Therefore, the residual load consisting of inflexible profiles as households, commercials, PtH and PV is calculated. The flexible components, like EVs are neglected in this case since they are not known yet. In the second method (flexLF) the EVs are also considered. Therefore, the load profiles for all EVs are calculated in a demand-led manner, assuming that grid fees were constant and no other use case is performed by the EVs. So, if only some EVs are reacting to the variable grid fees or the fees are only seldom differing from the fix ones, this should be a good solution since the predicted load then does not deviate far from the actual load. The third method (dynLF) predicts the current grid load more precisely since the forecast considers the optimised GCP with flexible EVs and SBS one after another. Therefore, first all GCP loads without flexibilities and with fixed fees are calculated for the load forecast. Based on the load forecast the grid fees are calculated and after that the first GCP with flexible EV or SBS is optimized. This process is then done for every remaining GCP with flexibilities. So, in this case the forecast for the last GCP is almost perfect since all other load profiles are known. This method could be described as a reservation system, with live pricing and after a GCP was optimized respectively made his reservation the prices for all others are calculated based on this information. Finally, within this method different GCP have different grid fees.

The **calculation of the grid fees** is based on the forecasted load of the transformer. If the transformer is not in a critical utilisation, the grid fee is the same as the fix one. If the load is above a threshold, the grid fee is increased for the first time. If the nominal power is reached the grid fee is increased for a second time. So, the aim is to reduce load of the cost optimized flexibilities by higher grid fees. On the other side, if the generation is too high, the grid fee is reduced in the same manner to trigger additional load.

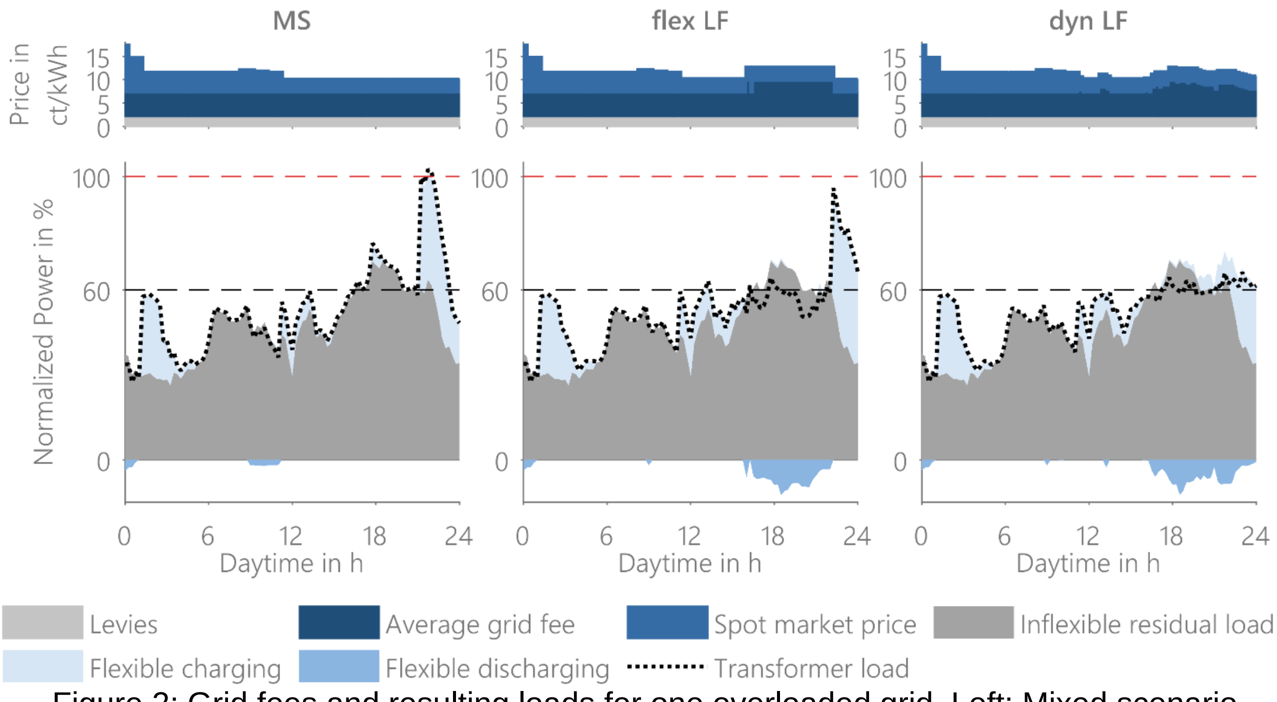

Figure 2: Grid fees and resulting loads for one overloaded grid. Left: Mixed scenario without variable grid fees, middle: variable grid fees with flexLF, right: variable grid fees with dynLF

Figure 2 shows the methods for an exemplary grid. On the left side the grid fees are fix, in the middle the flexLF and on the right side the dynLF method is shown. On top the resulting prices for the flexible components are shown. Below that, die different load types are displayed. The inflexible residual load here includes PV generation, household and HP load, as well as the load of EV and SBS, which do not react to variable grid fees. On the left side, the transformer is slightly overloaded in the evening hours due to low prices and high availability of EVs, that need to be charged. With the variable grid fees (middle), in this case the threshold is set to 60 %, the grid fee rises from 5.05 to 7.58 ct/kWh if the load

forecast estimates a transformer load above 60 %. This is shown between 5 and 9 pm. As reaction to the higher prices the EVs and SBSs are discharged. After the price falls to the normal level, the EVs are charged in times with lower inflexible load and therefore, no transformer overload occurs. In the scenario with the dynamic load forecast (right side), the average grid fee is smoother since the effect of the flexible loads is considered. This leads to a more constant gird utilisation around the threshold of 60 %.
Finally, the residual load is calculated based on the static and flexible load profiles at each GCP for each simulation timestep and the **load flow calculation** carried out by OpenDSS based on the Newton-Raphson method. As a result, voltages and currents in the grids are known and the grid status for different scenarios can be analysed.

Results

The different steps in the process of this case study are shown in Figure 3. Initially the 1206 grids were simulated based on the developed mixed scenario for 2040. As a result, 489 grids were overloaded, meaning that at least in one time step the nominal load for a transformer or cable was above 100 % or the voltage at any GCP was outside of the allowed range of ± 6 % of the nominal voltage [19]. In a comparative simulation, this time completely without EV, it was found that already in 300 of the 489 grids overloads occur only due to the inflexible loads, mainly due to HP. Since it is assumed that only 17 % of EV react to variable grid fees overloads within these grids cannot be solved through flexibility, so the sample was reduced to 189 grids.

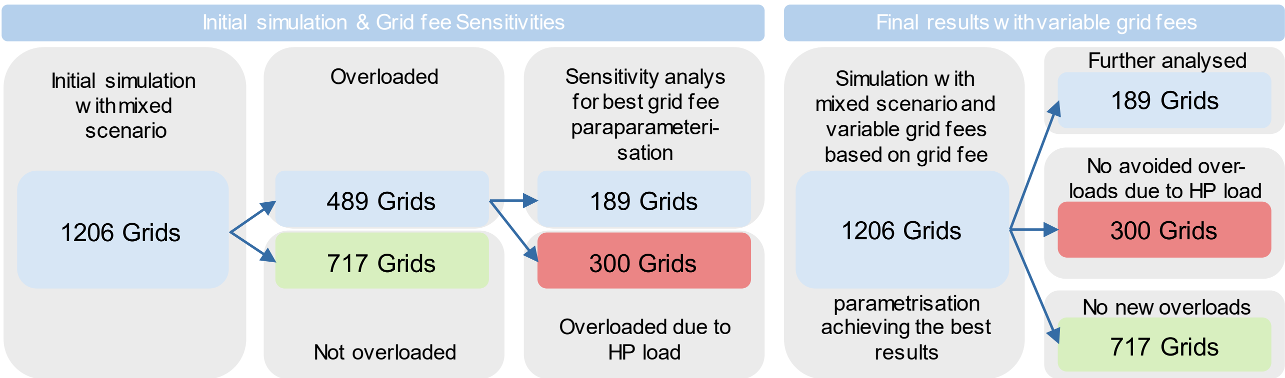

Figure 3 - Overview of the different sample sizes used in the process of the analysis

Based on these 189 grids parameters for the grid fee calculation were examined for sensitivity regarding grid relief to find the parameter combination with the best effect on grid relief. To analyse the effects of variable grid fees within the whole grid sample another simulation of the mixed scenario including the best parametrisation for variable grid fees was carried out to compare it with the simulation results of the mixed scenario without variable grid fees.
In the beginning the three possible load forecast methods inflexLF, flexLF and dynLF were analysed. The results can be seen in Figure 4 (A) showing the share of overloaded grids with the mixed scenario without variable grid fees as reference, where 100 % of the grid sample (189 grids) are overloaded. In 4 % of the grids the variable grid fee based on a load forecast consisting of inflexible, static loads lead to grid relief due to flexible EV and SBS. If the static EV load is considered in the load forecast (flexLF), the share of overloaded grids is reduced slightly to 93 %. The load forecast method dynLF leads to the most relieved grids due to the best estimation of the grid situation, because the local grid operator can estimate the grid load based on the reservations the costumers have to make for the load of their GCP. But even with a precise load forecast, 81 % of the grids remain overloaded.

To further analyse the cause, two parameters relevant to grid fee calculation were varied (B). Firstly, the grid fee spread (GF spread), meaning the level at which the grid charges increase when the transformer limits are exceeded and secondly, the transformer limits (utilisation limit) themselves. Within the varying load forecast a grid fee spread of 50 % and a utilisation limit of 60 % were chosen. Within the parameter sensitivities simulations were carried out with a grid fee spread of 15 % as well as 100 %, based on the best load forecast method (dynLF).

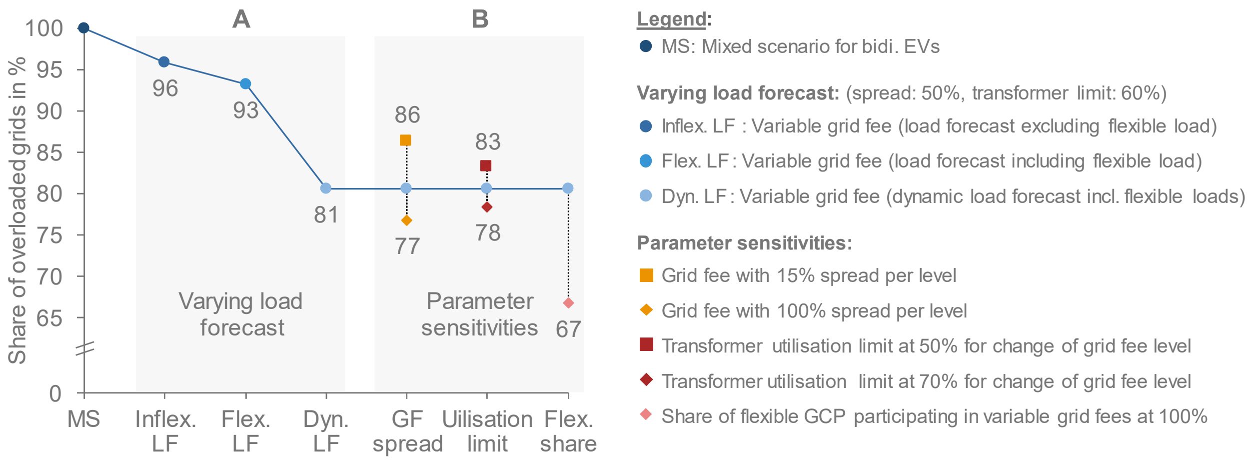

Figure 4 - Impact of different load forecast methods on the share of overloaded grids based on the mixed scenario **(A)** and analysis of three parameter sensitivities (spread per grid fee level, transformer utilisation limit and share of flexible GCP) based on the dynamic load forecast method **(B)**

The lower spread which results in a maximum of 6.6 ct/kWh is oriented to the costs of in total 30 % that fall back on operational management in the grids according to [20]. The 50 % spread leading to a maximum fee of 10.1 ct/kWh is roughly based on the currently common reductions of grid fees in Germany according to §14 a EnWG, which are offered if an electrical device can be switched of for a certain period [21]. A rising spread leads to slightly less overloaded grids and vice versa, with 77 % of overloaded grids remaining with a 100 % spread and a maximum of 15.15 ct/kWh.
Further on, a rising of the transformer utilisation level from 60 % to 70 % leads to 3 % less overloaded grids compared to the reference with dynamic load forecast. The fact that a higher transformer limit results in fewer overloads can be explained as follows. With a "later" increase of the grid charge level, there is an increased grid charge at fewer timesteps and thus more margin for an increase of the grid charge at the critical timesteps.
The results of the sensitivity analysis regarding parameters relevant for the grid fee calculation show, that the best results on grid relief can be achieved by the dynamic load forecast in combination with a grid feed spread of 100 % and a transformer utilisation level of 70 %. To further understand why most overloads nevertheless occur, the share of flexible GCP (Flex. share) was increased to 100 % in a final sensitivity, so all EV and SBS participate in variable grid fees. This reduces the share of overloaded grids to 67 %. Since this sensitivity is assumed to be unrealistic, as all GCP would have to have the necessary infrastructure to participate in variable grid fees, this approach was not pursued further. At the same time, however, it can be excluded that the overloads cannot be resolved due to too few GCP participating.
With these parameters relevant for the grid fee calculation (Spread: 100 %, Utilisation limit: 70 %) the mixed scenario with variable grid fees for the whole sample of 1206 grids was simulated again to check possible negative effects of the variable grid fees on not overloaded grids on the one hand and to analyse the 300 overloaded grids due to HP for

possible relief on the other hand. The result showed that neither previously not overloaded grids were overloaded nor that the grids overloaded by HP could be relieved. For this reason, the further evaluations refer to the sample of 189 grids.

Possible reasons for a high share of overloaded grids could still be voltage violations and line overloads, which are not considered in the grid fee calculation. For this reason, the mixed scenario is compared against the results of the mixed scenario with variable grid fees shown in Figure 5 and grouped by the reason of overload. As reference 100 % of the grids in the mixed scenario are overloaded due to line overloads, transformer overloads or voltage violations, with 66.1 % caused by load based overloaded transformers and 59.3 % caused by lower voltage violations. Line overloads just occur in 8.5 % of the grids in the mixed scenario and upper voltage violations as well as feed-based transformer overloads do not lead significantly to overloaded grids. A decrease of overloaded grids down to 76.2 % can be shown in the mixed scenario with variable grid fees. The best effect of the grid relief due to variable grid fees can be seen for the load-based transformer overloads decreasing down to 37.6 % compared to 66.1 %. The grid relief for voltage violations and overloaded lines is smaller, which can be explained by the fact that the grid fees are calculated based on the load forecast of the transformer.

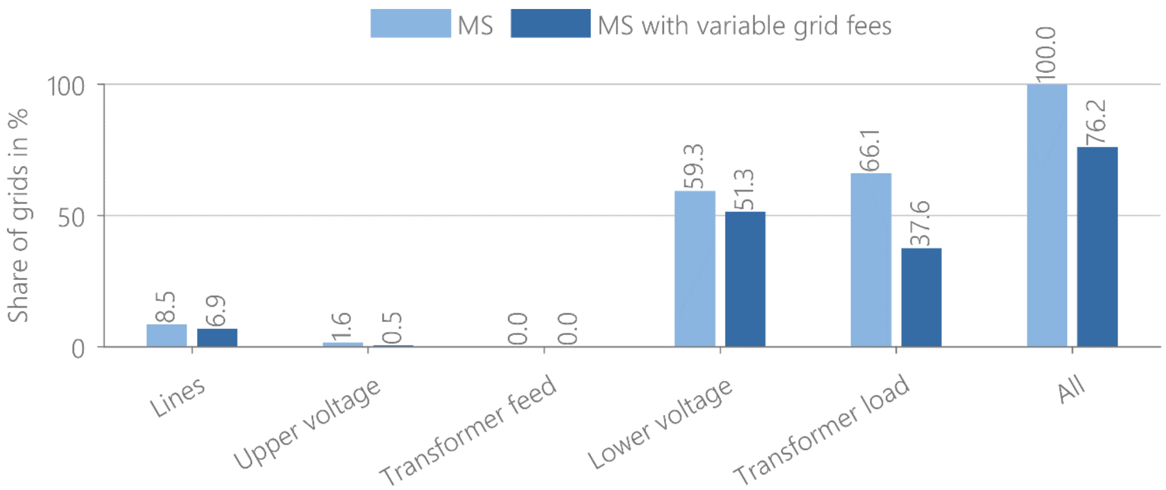

Figure 5 – Share of overloaded grids (189 grids in total) grouped by overload reason of the mixed scenario with and without variable grid fees and dynamic load forecast

To take a closer look at the effects in the grids that are not relieved, Figure 6 compares the hours with transformer overload for the 125 grids with overloaded transformers in the mixed scenario with and without variable grid fees. The figure is capped at a duration of 80 h as the first four transformers have higher overload durations in the mixed scenario (276 h, 119.5 h, 101.5 h, 95 h). In total, 56 transformers could be relieved by the variable grid fees with dynamic load forecasting and the duration of transformer overload could be reduced by 82 % on average. This shows that the variable grid fees also relieve the overloaded transformers to a certain extent.

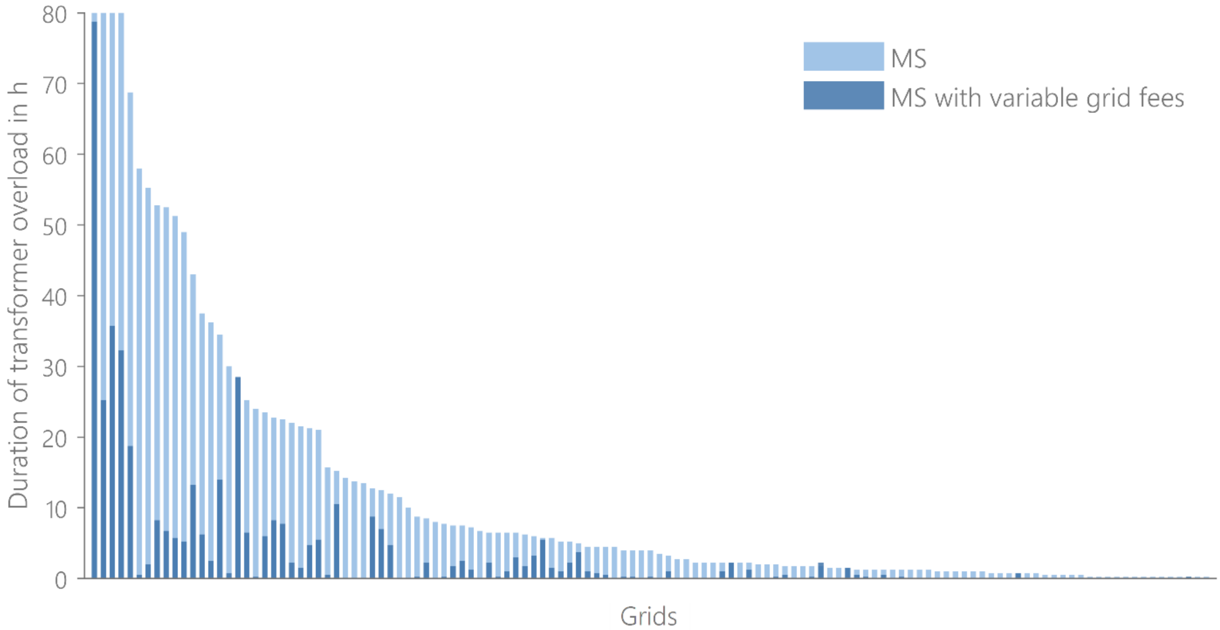

Figure 6: Duration of transformer overlaod with and without variable grid fees and dynamic load forecast

To analyse the financial impact on the grid operator and the customers, the grid fees for each GCP were calculated. From a grid operator's perspective, the relevant average grid fee weighted based on the amount of energy received from the grid is 4.86 ct/kWh across all 189 grids and varies between 3.2 ct/kWh to 5.63 ct/kWh. In return the grid operator can also transmit more energy through the grids due to the grid-serving consumer behavior. Whether the lower specific grid fees have a negative impact on the revenues of the grid operator cannot be answered due to the lack of a grid expansion analysis and the associated costs. At the same time, the median of customers with variable grid fees pays 3.39 ct/kWh whereas customers without variable grid fees pay 5.05 ct/kWh. The lower specific grid fees for flexible customers are due to the customers' ability to obtain energy at times of low load and feed it back at times of high load to remunerate the grid fee by the grid operator. This leads to lower grid fees especially when PV systems are available.

Conclusions

The simulation of the mixed scenario without variable grid fees showed that a total of 489 of the 1206 grids are overloaded and of these, 300 grids are overloaded by the inflexible additional HP load, which cannot be finally solved by the flexibility of grid serving EVs and SBSs. The sensitivity analyses for the remaining 189 grids have shown that using a dynamic load forecast, both a higher spread and a higher load limit led to more grid load reductions. In the combination of dynamic load forecasting, a spread of 100 % and 70 % utilisation, the share of overloaded grids is reduced to 76 % in the mixed scenario with variable grid fees. However, when the entire sample was simulated again, none of the 300 grids overloaded mainly by HPs could be relieved, even with the most effective parameters for grid fee calculation and load forecast. At the same time, the use of variable grid fees did not result in any new overloads in grids that were not previously overloaded. In the case of transformer overloads (125 of 189 grids), the hours with transformer overloads could be reduced by 82 % on average.
The fact that most grids cannot be completely relieved is due to several effects. On the one hand, in grids with high and long-lasting overloads, grid fees are high for several days at a time and thus lose their grid-serving incentive compared to the spot market price. Furthermore, the grid fee spreads can also be completely overlaid by the spot market

spread, so that they are no longer significant. But even if many EVs and SBS are not traded simultaneously on the spot market (V2G) but react primarily to variable grid fees, the flexibility is not sufficient to completely relieve most of the grids. This is also since line overloads and voltage violations contribute to the share of overloaded grids but are not included in the calculation for the variable grid fees, as it is assumed that, from the grid operator's point of view, only a forecast of the transformer load is possible for the time being.
Since the focus of this work is on grid overloads caused by loads due to the chosen scenario further research regarding the effects in grids with overloads caused by distributed generation units, like PV plants, is necessary. Furthermore, in future not only EVs and SBS could react on price signals, but also HPs, leading to a higher flexibility. The design of variable grid fees also leaves further options for examinations. For example, more than three price levels can be selected, or voltage and line problems can be considered based on better grid condition forecasts. Also, the question, how cost-optimised consumers can contribute to avoiding grid expansion by using a grid-supporting price signal as variable grid fees needs to be further investigated.

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